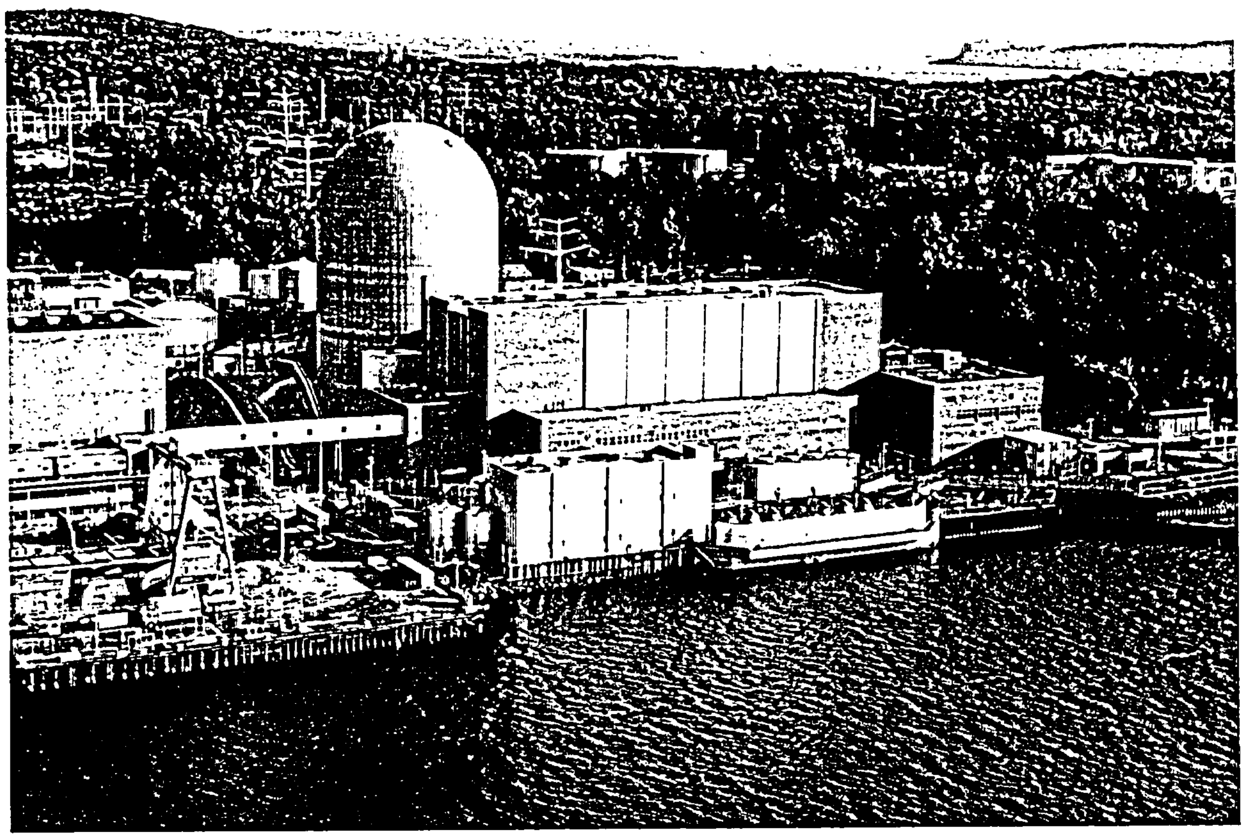
Entergy Nuclear Operations, Incorporated

Indian Point Nuclear Generating Unit No. 3



Stretch Power Uprate
License Amendment Request Package

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 734 6700

Fred Dacimo
Site Vice President
Administration

June 3, 2004

Re: Indian Point Unit No. 3
Docket No. 50-286
NL-04-069

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

SUBJECT: **Proposed Changes to Technical Specifications: Stretch Power Uprate (4.85%) and Adoption of TSTF-339**

References:
1. Technical Specification Task Force Traveler TSTF-339, Rev 2; "Relocate Technical Specification Parameters to the COLR", dated June 13, 2000.
2. NRC Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications", dated January 31, 2002.
3. Westinghouse WCAP –10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," dated January 1993.
4. NRC Review Standard (RS)-001, "Draft Review Standard for Extended Power Uprates".
5. Entergy letter to NRC, NL-04-068, "Proposed Changes to Technical Specifications Regarding Adoption of Alternate Source Term", dated June 2, 2004

Dear Sir:

Pursuant to 10 CFR 50.90, Entergy Nuclear Operations, Inc, (Entergy) hereby requests an amendment to the Operating License for Indian Point Nuclear Generating Unit No. 3 (IP3), to increase the maximum authorized reactor core power level from 3067.4 MWt to 3216 MWt.

The proposed nominal increase of 4.85% in rated thermal power is based on analyses contained in Attachment III (WCAP-16212-P). Six copies of the proprietary version and two copies of the nonproprietary version of the WCAP are being provided.

This amendment request also proposes to adopt TSTF-339 (Reference 1) regarding relocation of certain cycle-specific parameters from the Technical Specifications to the Core Operating Limits Report. The values for some of these parameters are changing as a result of the proposed power increase. The methodology used and the resulting new parameter values are described in Attachment III. In addition, Entergy is proposing changes to several Reactor Protection System and Engineered Safeguards Features System allowable values that are not affected by the proposed power increase. These allowable value changes are described in Attachment I.
The proposed changes regarding a power increase, adoption of TSTF-339, and several allowable values, have been evaluated in accordance with 10 CFR 50.91 (a)(1) using the criteria of 10 CFR 50.92 (c) and Entergy has determined that this proposed change involves no significant hazards considerations (Attachment I). The proposed change to the Facility Operating License and changes to the current Technical Specification and Bases pages are provided in Attachment II.

In accordance with 10CFR50.91, a copy of this application and the associated attachments are being submitted to the designated New York State official.

The evaluation of the proposed increase in rated thermal power has been performed following the guidance of References 2 and 3. Although Reference 4 addresses power uprate requests greater than that being requested for IP3, Entergy has reviewed the guidance of Reference 4 to identify additional information that is being provided in selected areas to support NRC evaluation and approval of this request. Safety analyses that assess hypothetical accident dose consequences at the proposed higher power level use the alternate source term (AST) methodology in accordance with 10 CFR 50.67. Therefore, NRC approval of Entergy's proposed adoption of AST (Reference 5) is required to support the proposed power increase.

Also provided, as Enclosure A, is Westinghouse authorization letter dated June 1, 2004 (CAW-04-1841), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice. As Attachment III contains information proprietary to Westinghouse Electric Company, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information that is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390 of the Commission's regulations. The non-proprietary version of the WCAP is provided as Enclosure B.

Correspondence with respect to the copyright on proprietary aspects of the items listed above or the supporting affidavit should reference CAW-04-1841 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P. O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Entergy requests approval of the proposed amendment by March 2005 to support implementation activities and operation at the new power level following completion of the 3R13 Spring 2005 refueling outage. There are no new commitments identified in this submittal. If you have any questions or require additional information, please contact Mr. Kevin Kingsley at 914-734-6695.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 6/3/2004.

Sincerely,

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachments:
I. Analysis of Proposed Technical Specification Changes
II. Proposed Technical Specification and Bases Changes (markup)
III. Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report, WCAP-16212-P, dated June 1, 2004

cc: Mr. Patrick D. Milano, Senior Project Manager
Project Directorate I,
Division of Reactor Projects I/II
U.S. Nuclear Regulatory Commission
Mail Stop O 8 C2
Washington, DC 20555

Mr. Hubert J. Miller (w/o prop. encl)
Regional Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Resident Inspector's Office (w/o prop. encl)
Indian Point Unit 3
U.S. Nuclear Regulatory Commission
P.O. Box 337
Buchanan, NY 10511

Mr. Peter R. Smith (w/o prop. encl)
President, NYSERDA
17 Columbia Circle
Albany, NY 12203

Mr. Paul Eddy (w/o prop. encl)
New York State Dept. of Public Service
3 Empire State Plaza
Albany, NY 12223

ATTACHMENT I TO NL-04-069

ANALYSIS OF PROPOSED TECHNICAL SPECIFICATION CHANGES REGARDING INCREASE OF LICENSED THERMAL POWER, ADOPTION OF TSTF-339, AND ALLOWABLE VALUE CHANGES

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

1.0 DESCRIPTION

This is a request to amend Operating License DPR-64, Docket No. 50-286 for Indian Point Nuclear Generating Unit No. 3 (IP3) for the following items:

- Proposed increase in rated thermal power from 3067.4 MWt to 3216; an increase of approximately 4.85%,
- adopt TSTF-339 regarding relocation of technical specification parameters to the Core Operating Limits Report (COLR), and
- revision of allowable values specified for certain reactor protection system (RPS) and Engineered Safeguards Features (ESF) functions.

The proposed increase in rated thermal power has been evaluated using the guidance contained in References 1, and 2. The analyses and evaluations performed to support operation at the higher power level are described in Attachment III (WCAP 16212-P). Although the proposed power increase for IP3 is classified as a Stretch Power Uprate (SPU), Entergy also reviewed the guidance contained in Reference 3 for Extended Power Uprates (EPU). Relevant information based on this guidance, as well as NRC review comments on similar license amendment requests has been incorporated in Attachment III.

The technical specifications for IP3 currently contain the values for several parameters that are subject to change as a result of cycle-specific core reload analyses. TSTF-339 (Reference 4) addresses the relocation of these values to a COLR. This approach reduces the administrative burden associated with implementing these cycle-specific changes by using a change process governed by 10 CFR 50.59 instead of 10 CFR 50.92. New values for parameters being relocated to the COLR that are being changed as a result of the proposed power increase are described in Attachment III.

This license amendment request includes changes to several allowable values specified for RPS and ESF functions. Three of the four changes proposed for RPS functions are being made as a result of analysis assumption changes for SPU analyses. The remaining RPS function and the three proposed changes for ESF functions are not required for operation at SPU conditions. However, as part of the SPU project, Entergy evaluated the existing RPS and ESF allowable values and identified other specific functions where changes are desirable as described in the following section. In all cases where a new allowable value is proposed, the revised value incorporates sufficient conservatism to be consistent with an analysis methodology based on ISA-RP67.04 Method 2. This approach does not represent a proposed change in the current licensing basis methodology used for establishing allowable values for IP3.

2.0 PROPOSED CHANGES

Facility Operating License:

Page 3; change Rated Thermal Power from 3067.4 MWt to 3216 MWt.

Technical Specifications:

1. Rated Thermal Power (RTP), Tech Spec Section 1.1

   Current value of 3067.4 MWt is being changed to 3216 MWt consistent with the analysis and evaluation in Attachment III. There are no Bases for this Tech Spec section.

2. Reactor Core Safety Limits, Tech Spec Section 2.1.1

   TSTF-339 is being adopted for this specification. Changes consist of:

   - Relocating updated Figure 2.1-1 (Reactor Core Safety Limits) to the COLR,
   - Adding new requirements 2.1.1.1 and 2.1.1.2 for DNB and peak fuel centerline temperature limits, respectively; and
   - Related Bases changes as specified in TSTF-339.

   The Reactor Core Safety Limits curve has been updated to reflect the proposed stretch uprate conditions. This new curve, being relocated to the COLR, is shown in Figure 6.3-1, Section 6.3 of WCAP-16212-P, provided in Attachment III.

3. Changes in Allowable Values in Table 3.3.1-1 (RPS Instrumentation)

   - **Function 2.a** Power range neutron flux (high):
     Change allowable value from $\leq$ 109% RTP to = 111%.

   This change is not required by the proposed increased in rated thermal power. The current safety analysis limit (SAL), 118%, is not being changed for power uprate. The current allowable value (109%) is more conservative than needed to ensure protection of the associated SAL, and is a nominal value based on original plant design specifications. The proposed new allowable value (111%) is justified by the site-specific instrument loop uncertainties and use of this value provides additional margin for as-found surveillance testing of this instrument channel. The proposed new value also includes conservatism consistent with a calculation method using ISA-RP67.04 Method 2. The additional conservatism applied for this value does not adversely affect the operating margin to the trip setpoint for this function. There are no Bases changes required for this function.

- **Function 7a** Pressurizer Pressure - Low:
  Change allowable value from $\geq$ 1790 psia to = 1900 psia

The SAL associated with this function is being increased from 1714.7 psia to 1850 psia to provide margin for the hot zero power main steam line break safety analysis at SPU conditions (Section 6.3.11 of WCAP-16212-P). The current allowable value (1790 psia) is being increased (1900 psia) to accommodate the increase in the SAL and to add additional conservatism consistent with a calculation method using ISA-RP67.04 Method 2. There are no Bases changes required for this function.

- **Function 5, Note 1** Overtemperature delta -T:
  Change allowable value as described below and adopt TSTF-339:

This function provides DNB protection for non-LOCA transients. The SAL (K1 max) associated with this function is being increased from 1.40 to 1.42 (Section 6.10 of WCAP-16212-P) to increase the channel uncertainty margin. The corresponding allowable value (K1) is being decreased from 1.285 to 1.26. In terms of delta-T span, this corresponds to a decrease from 5.8% to 2.8%. Although the SAL for this function is being increased, the allowable value is being decreased to ensure that the proposed new allowable value includes sufficient conservatism to be consistent with a calculation method using ISA-RP67.04 Method 2. Applying this additional conservatism does reduce the existing allowable value margin for this function.

Note 1 is also being revised to reflect adoption of TSTF-339, which relocates parameters to the COLR and expresses the SAL in terms of delta-T span. The allowable value equation used for this function reflects the current licensing basis for IP3.

- **Function 6, Note 2:** Overpower delta -T:
  Change allowable value as described below and adopt TSTF-339:

This function provides fuel centerline temperature protection for non-LOCA transients. The SAL (K4 max) associated with this function is being increased from 1.162 to 1.164 (Section 6.10 of WCAP-16212-P) to increase the channel uncertainty margin. The corresponding allowable value (K4) is being decreased from 1.154 to 1.10. In terms of delta-T span, this corresponds to a decrease from 3.7% to 1.8%. Although the SAL for this function is being increased, the allowable value is being decreased to ensure that the proposed new allowable value includes sufficient conservatism to be consistent with a calculation method using ISA-RP67.04 Method 2. Applying this additional conservatism does reduce the existing allowable value margin for this function.

Note 2 is also being revised to reflect adoption of TSTF-339, which relocates parameters to the COLR and expresses the SAL in terms of delta-T span.

The allowable value equation used for this function reflects the current licensing basis for IP3.

There are no Bases changes associated with the above proposed changes to RPS allowable values.

4. Changes in Allowable Values in Table 3.3.2-1 (ESFAS Instrumentation)

- **Function 1.d** Pressurizer Pressure – Low
  Change the allowable value from ≥ 1690 psig to ≥ 1710 psig.

This change is not required by the proposed increased in rated thermal power. The SAL is being reduced slightly from 1650 psia to 1648.7 psia to ensure consistency among the various safety analyses that credit this trip function. The existing margin to the current allowable value is preserved. However, the existing allowable value is slightly below the bottom of the instrument span (1700 psig) for this channel. Although this is acceptable, because the trip setpoint implemented for this function is on span, Entergy is proposing a new allowable value that will be above the bottom of the instrument span. Sufficient additional conservatism is also being provided for this new allowable value to be consistent with a calculation method based on ISA-RP67.04 Method 2.

- **Function 1.f** High Steam Flow - Safety Injection, Coincident with Tavg Low:
  Change the allowable value from ≥ 538°F to ≥ 540.5°F.

This change is not required by the proposed increase in rated thermal power. The SAL associated with this function remains at 535°F. The proposed new allowable value will be above the bottom of the instrument span (540°F) for this channel, and sufficient additional conservatism is being provided for this allowable value to be consistent with a calculation method using ISA-RP67.04 Method 2.

- **Function 4.d** High Steam Flow - Steam Line Isolation, Coincident with Tavg – low:
  Change the allowable value from ≥ 538°F to ≥ 540.5°F.

The same description as provided for Function 1.f applies here.

There are no Bases changes associated with the above proposed changes to ESFAS allowable values.

5. RCS DNB Limits, Tech Spec Section 3.4.1

The current Tech Spec limit for Reactor Coolant System (RCS) total flow rate of 375,600 gpm is a limit established as the Minimum Measured Flow (MMF). Consistent with TSTF-339, Entergy will replace this existing Tech Spec MMF value with a corresponding value of Thermal Design Flow (TDF). TDF must be lower than the MMF by at least the total instrument channel uncertainty on flow measurement and indication. The MMF will be relocated from Tech Specs to the COLR, and the MMF value will be lowered from 375,600 gpm to 364,700 gpm. This increases margin between the MMF used in various safety analyses (that statistically combine uncertainties) and actual flows being measured at IP3. Also, the value of the TDF used in various safety analyses is being increased from 323,600 gpm to 354,400 gpm (Table 7.2-1 of WCAP-16212-P). The increase in TDF eliminates excess margin between current MMF and TDF values (16% between 375,600 gpm and 323,600 gpm). However, the 2.9% margin between the revised MMF (364,700 gpm) and TDF (354,400 gpm) properly represents the calculated instrument channel uncertainty associated with flow indication. The SPU flow measurement uncertainty was calculated using the existing methodology described in WCAP-11397-P-A, "Revised Thermal Design Procedure", and remains at the current value of 2.9%.

In addition to the above changes regarding RCS total flow rate, the adoption of TSTF-339, also relocates the limiting values for pressurizer pressure and RCS average loop temperature to the COLR.

These proposed changes modify LCO 3.4.1 and the related Surveillances. There are no changes required for the Applicability or Actions. The associated Bases changes from TSTF-339 are also being adopted.

6. Pressurizer (water level), Tech Spec Section 3.4.9

The safety analysis initial condition assumption for pressurizer water level is being increased from 58.3% to 59.3% to bound the upper limit of T_{avg} (572°F) used in the safety analyses. Tech Spec Section 3.4.9 is also being revised to specify the limit for indicated level instead of actual level. The proposed Tech Spec limit of 54.3% includes an allowance of 5% for instrument uncertainty. This value is an input assumption uncertainty, not a statistically analyzed uncertainty. An allowance of 5% is supported by historical data from the drift monitoring program. These proposed changes modify LCO 3.4.9.a and the related Surveillance. There are no changes required for the Applicability or Actions. Related changes are also proposed for Bases Section 3.4.9.

7. Main Steam Safety Valves, Tech Spec Section 3.7.1

The proposed changes reflect new limits corresponding to the slightly higher steam flow at SPU conditions. Related changes are also proposed for Bases Section 3.7.1.

8. Containment Leakage Rate Testing Program, Tech Spec Section 5.5.15

The current peak accident containment pressure for the design basis loss of coolant accident is 38.77 psig. This section is being revised to reflect the new value of 42.0 psig for the LOCA analysis at SPU conditions (Section 6.5 of WCAP 16212-P). Also, this section is being revised to identify the containment design pressure, consistent with TSTF-52, for a plant using Option B of 10 CFR

50 Appendix J. This tech spec section currently identifies the accident pressure result for a steam line break and also specifies a minimum pressure for containment leakage testing. Both of these parameters are being deleted. The relevant accident pressure for this program is based on LOCA, not steam line break, and test pressure requirement is identified in ANSI / ANS-56.8, which is referenced in Regulatory Guide 1.163. There are no Bases for this Tech Spec section.

9. Core Operating Limits Report (COLR), Tech Spec Section 5.6.5

Section 5.6.5.a is being revised as a result of adopting TSTF-339 for the relocation of parameters to the COLR. NUREG-1431 requires that this section must reference individual specifications that address core operating limits. Three additional specifications must be added to the existing list in this section:

- Technical Specification 2.1, Safety Limits (SL)
- Technical Specification 3.3.1, Reactor Protection System Instrumentation;
- Technical Specification 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

These additional specifications are being added as a result of the above proposed changes 2, 3 (for Functions 5 and 6), and 5, respectively.

Section 5.6.5.b is being revised to identify three additional references that describe analytical methods used to determine core operating limits. WCAP-11397-P-A is being added as reference 3.b, WCAP-8745-P-A is being added as reference 3.c, and WCAP-10054-P-A, Addendum 2, Revision 1, is being added as reference 3.e. The addition of references 3.b and 3.c support the adoption of TSTF-339. The addition of reference 3.e is appropriate to ensure a complete list of references. This reference applies to current analyses and SPU analyses.

There are no Bases for this Tech Spec section.

3.0 BACKGROUND

A. Stretch Power Uprate:

The Indian Point Nuclear Generating Unit No. 3 (IP3) nuclear steam supply system was designed to be capable of operation at 3216 MWt and was originally licensed (AEC Safety Evaluation Report dated September 21, 1973) for a core thermal power rating of 3025 MWt. IP3 is currently licensed for a core thermal power rating of 3067.4 MWt, based on the 1.4% measurement uncertainty recapture (MUR) power uprate approved by the NRC in License Amendment 213, issued November 26, 2002. The MUR approach allows use of improved calorimetric instrumentation for operation based on a measurement uncertainty of 0.6% instead of the 2% uncertainty assumption originally required by 10 CFR 50, Appendix K.

This amendment request proposes to increase the licensed core thermal power to 3216 MWt (nominal 4.85% increase) based on new analyses and evaluations for operation at the higher power level as described in WCAP-16212-P (Attachment III). Applicable guidance from References 1, 2, and 3 was used for this project, which is classified as a Stretch Power Uprate (SPU), based on uprate categories defined by NRC. The safety analyses with respect to 10 CFR 50, Appendix K limits have been performed based on a measurement uncertainty of 2% (3216 MWt plus 2%). Therefore, the administrative controls (required actions and completion times) established in Amendment 213 for inoperable calorimetric instrumentation (Leading Edge Flow Meters) will no longer be required for operation at the proposed new power level.

Entergy plans to implement the proposed stretch power increase in phases because of plant modifications on balance-of-plant (BOP) equipment. Phase I modifications, involving the high-pressure turbine and the moisture separator reheaters, will be accomplished during the Spring 2005 refueling outage. During Phase I, Entergy plans to initially operate at a power level less than 4 percent above the current power level until Phase II secondary side plant modifications or evaluations have been completed to support power operations up to 3216 MWt. The timing for Phase II modifications, involving the low-pressure turbines and cooling for the iso-phase bus ducts will be based on economic considerations. These remaining modifications are not limitations on the validity of the safety analyses for the proposed new core thermal power of 3216 MWt. Additional information regarding plant modifications is provided in Section 1.5 of WCAP 16212-P.

B. Adoption of TSTF-339

The IP3 Technical Specifications currently contain cycle-specific parameters that are subject to change as a result of updated analysis performed to support core reloads. Based on references 4, 5, and 6, Entergy propose to relocate the cycle-specific values for these parameters to the Core Operating Limits Report (COLR). Future changes to these values can be implemented in accordance with 10 CFR 50.59 change control processes and the administrative controls established for core reload designs. Requirements will be retained in the Technical Specifications for limiting values required to assure that safety limits are met. Technical Specifications also will identify the NRC approved analysis methods that must be used to establish new values for the affected COLR parameters.

C. Revision of selected RPS and ESF Allowable Values

As a result of changes in safety analysis limit assumptions for three RPS trip functions, changes are needed to the corresponding tech spec allowable values for these functions. Since these allowable values are being revised, Entergy is proposing to modify four other allowable values (one RPS and three ESF) for reasons described in Section 2.0, even though these other allowable value changes are not the result of the proposed power increase.

4.0 TECHNICAL ANALYSIS

The technical analysis for the proposed increase in rated thermal power is based on applicable guidance provided in Reference 1, 2, and 3. Refer to Attachment III, WCAP 16212-P for detailed discussion of the technical analyses completed.

There is no technical analysis needed for the proposed adoption of TSTF-339. This is an administrative change, consisting of the relocation of cycle-specific parameters from the technical specifications to the Core Operating Limits Report. The existing technical analysis methodologies for calculating the values of the affected relocated parameters are not being changed. Consistent with TSTF-339, safety limit parameters and the NRC-approved methodologies for calculating cycle-specific values that satisfy the safety limits are retained in the Technical Specifications.

The methodology used to establish Tech Spec allowable values for RPS and ESF instrument channels is the same as that used to support allowable values established in prior license amendments (Reference 7). The methodology used by Entergy for IP3 conforms to Regulatory Guide 1.105, Revision 2 (Instrument Setpoints for Safety-Related Systems) and ISA-RP67.04, Part II, Draft 9. For purposes of this amendment request, Entergy has incorporated additional conservatism in the proposed new allowable values to bound an analysis method based on Method 2 of ISA-RP67.04.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

Entergy Nuclear Operations, Inc. (Entergy) has evaluated the safety significance of the proposed increase in rated thermal power, adoption of TSTF-339, and proposed changes to several allowable values for Reactor Protection System (RPS) and Engineered Safety Feature (ESF) system functions according to the criteria of 10 CFR 50.92, "Issuance of Amendment," Entergy has determined that the subject change does not involve a Significant Hazards Consideration 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 evaluations and analyses associated with this proposed change to core power level have demonstrated that all applicable acceptance criteria for plant systems, components, and analyses (including the Final Safety Analysis Report Chapter 14 safety analyses) will continue to be met for the proposed increase in licensed core thermal power for Indian Point 3 (IP3). The subject increase in core thermal power will not result in conditions that could adversely affect the integrity (material, design, and construction standards) or the operational performance of any potentially affected system, component or analysis. Therefore, the probability of an accident previously evaluated is not affected by this change. The subject increase in core thermal power will not adversely affect the ability of any safety-related system to meet its intended safety function. Further, the radiological dose evaluations in support of this power uprate effort show all acceptance criteria are met.

The relocation of cycle-specific core operating limits from the Technical Specifications to the Core Operating Limits Report (COLR), in accordance with TSTF-339, has no influence or impact on the probability or consequences of a Design Basis Accident. Adherence to the COLR and accepted methodologies for establishing COLR parameters continues to be controlled by the plant Technical Specifications. Relocation of cycle-specific values to the COLR while maintaining the limiting requirements in the Technical Specifications reduces administrative burden associated with processing license amendments for routine core reload designs.

RPS and ESF allowable values established in plant technical specifications represent acceptance criteria used by plant personnel in assessing the operability of instrumentation channels. Allowable values are not accident initiators and have no role in the probability of occurrence of an accident. Safety analyses for design basis accidents use certain assumptions (Safety Analysis Limits) regarding the actuation of RPS and ESF protective functions. The proposed allowable values are developed using a methodology that assures the accident analysis assumptions are valid and the consequences of previously analyzed accidents continue to meet established limits.

Therefore, the proposed changes described in this license amendment request do not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

Response: No

The analyses and evaluations performed for the proposed increase in power show that all applicable acceptance criteria for plant systems, components, and analyses (including FSAR Chapter 14 safety analyses) will continue to be met for the proposed power increase in IP3 licensed core thermal power. The subject increase in core thermal power will not result in conditions that could adversely affect the integrity (material, design, and construction standards) or operational performance of any potentially affected system, component, or analyses. The subject increase in core thermal power will not adversely affect the ability of any safety-related system to meet its safety function. Furthermore, the conditions and changes associated with the subject increase in core thermal power will neither cause initiation of any accident, nor create any new credible limiting single failure. The power uprate does not result in changing the status of events previously deemed to be non-credible being made credible. Additionally, no new operating modes are proposed for the plant as a result of this requested change.

The relocation of cycle-specific core operating limits from the Technical Specifications to the Core Operating Limits Report (COLR), in accordance with TSTF-339, does not involve any changes to plant equipment or the way is which the plant is operated. There are no new accident initiators or causal mechanisms being introduced by this proposed change. Relocation of cycle-specific values to the COLR while maintaining the limiting requirements in the Technical Specifications reduces administrative burden associated with processing license amendments for routine core reload designs.

RPS and ESF allowable values established in plant technical specifications represent acceptance criteria used by plant personnel in assessing the operability of instrumentation channels. Revising allowable values does not involve installation of new equipment, modification to existing equipment, or a change in plant operation that could create a new or different accident scenario.

Therefore, the proposed changes described in this license amendment request will not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Response: No

The analyses and evaluations associated with the proposed increase in power show that all applicable acceptance criteria for plant systems, components, and analyses (including FSAR Chapter 14 safety analyses) will continue to be met for this proposed increase in IP3 licensed core thermal power. The subject increase in core thermal power will not result in conditions that could adversely affect the integrity (material, design, and construction standards) or operational performance of any potentially affected system, component, or analysis. The subject power uprate will not adversely affect the ability of any safety-related system to meet its intended safety function.

Adoption of TSTF-339 allows relocation of cycle-specific parameters to the COLR, while maintaining limiting requirements in the Technical Specifications. Approved methodologies for calculating cycle-specific parameters are maintained in the Technical Specifications, and changes to the COLR are subject to the requirements and controls of 10 CFR 50.59. This assures that required margins to safety limits are maintained.

The proposed new allowable values are developed using established methodologies and incorporate additional conservatism that assures the validity of analysis limits assumed in the evaluation of hypothetical accidents.

Therefore, the proposed changes described in this license amendment request will not involve a significant reduction in the margin of safety.

5.6 Applicable Regulatory Requirements / Criteria

The proposed increase in rated thermal power and related changes to the plant Technical Specifications has been evaluated in accordance with NRC guidance provided in Regulatory Issue Summary 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002 (Reference 1). The analyses and evaluations completed to support the proposed increased in core thermal power demonstrate that acceptance criteria including those established by regulatory requirements continue to be met.

The affect of the new maximum power level on structures, systems, and components of the nuclear steam supply system and the balance-of-plant was evaluated to assure that applicable regulatory requirements and criteria are met. A description of the analyses and evaluations performed is provided in the Stretch Power Uprate Licensing Amendment Report (WCAP 16212-P) provided with this application for amendment. Table 1-2 of that report provides summary level information and shows that current design or licensing basis acceptance criteria continue to be met for operation at the uprated conditions.

The proposed relocation of various cycle-specific parameters from the technical specifications to the Core Operating Limits Report is based on TSTF-339, which has been approved by the NRC. Also, this proposed change conforms to Generic Letter 88-16 (Removal of Cycle-Specific Parameters Limits from Technical Specifications). Future changes to the COLR parameters are subject to the requirements of 10 CFR 50.59.

This license amendment request also contains proposed changes to allowable values for certain reactor protection system and engineered safety feature system instrument channels. These proposed changes are in accordance with 10 CFR 50.36 regarding limiting safety system settings. The methodology used by Entergy to establish allowable values conforms to Regulatory Guide 1.105.

Entergy has determined that the proposed change does not require any exemptions or relief from regulatory requirements, other than those technical specification changes requested in this submittal. Additionally, this change does not affect conformance with any General Design Criteria differently than described in the FSAR.

5.7 Environmental Considerations

The proposed changes in this license amendment, including the related changes to the plant technical specifications do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed 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.

6.0 PRECEDENCE

The NRC has previously approved similar applications regarding an increase in rated thermal power for Palo Verde 2 and Kewaunee, and numerous MUR applications including Indian Point 2 and Indian Point 3. Recent NRC approvals for adoption of TSTF-339 include Millstone and Catawba.

7.0 REFERENCES

1. NRC Regulatory Issue Summary 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002.

2. Westinghouse WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," dated January 1983.

3. NRC Review Standard (RS)-001, "Review Standard for Extended Power Uprates", Revision 0, December 2003.

4. Technical Specification Task Force Traveler TSTF-339, Rev 2; "Relocate Technical Specification Parameters to the COLR", dated June 13, 2000.

5. NRC Generic Letter 88-16, "Removal of Cycle-Specific Parameters from Technical Specifications," dated October 4, 1988.

6. Westinghouse WCAP-14483-A, "Generic Methodology for Expanding Core Operating Limits Report," dated January 1999.

7. NRC Safety Evaluation Report dated February 27, 2001 for IP3 License Amendment 205, Conversion to Improved Standard Technical Specifications.

ATTACHMENT II TO NL-04-069

MARKUP OF TECHNICAL SPECIFICATION AND BASES PAGES

FOR PROPOSED CHANGES REGARDING

INCREASE OF LICENSED THERMAL POWER,

ADOPTION OF TSTF-339, AND ALLOWABLE VALUE CHANGES

- Facility Operating License, page 3
- Technical Specification pages:

Page 1.1-5	Page 3.4.1-1
Page 2.0-1	Page 3.4.1-2
Page 2.0-2	Page 3.4.9-1
Page 3.3.1-13	Page 3.4.9-2
Page 3.3.1-15	Page 3.7.1-3
Page 3.3.1-19	Page 5.0-31
Page 3.3.1-20	Page 5.0-34
Page 3.3.2-8	Page 5.0-35
Page 3.3.2-11	

LEGEND FOR MARKUP NOTATIONS:

S = change required for proposed stretch uprate

T = change per TSTF-339 (Relocate Parameters to COLR)

X = other proposed changes not required for stretch uprate

- Technical Specification Bases pages: (for information only)

Pages B 2.1.1-2, -3, and -5
Pages B 3.4.1-1 to -3 and -5
Pages B 3.4.9-2 to -3
Page B 3.7.1-3 and -4

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

FROM IP3
FACILITY OPERATING LICENSE

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

(1) Maximum Power Level

ENO is authorized to operate the facility at steady state reactor core Power levels not in excess of 3067.4 megawatts thermal (100% of rated power) — Amdt. 213, 11-26-2002

3216 (S)

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 220 are hereby incorporated in the License. ENO shall operate the facility in accordance with the Technical Specifications.

(3) (DELETED)

(4) (DELETED)

D. (DELETED) — Amdt. 46, 2-16-83

E. (DELETED) — Amdt. 37, 5-14-81

F. This amended license is also subject to appropriate conditions by the New York State Department of Environmental Conservation in its letter of May 2, 1975, to Consolidated Edison Company of New York, Inc., granting a Section 401 certification under the Federal Water Pollution Control Act Amendments of 1972.

G. ENO shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Indian Point 3 Nuclear Power Plant Physical Security Plan," with revisions submitted through December 14, 1987; "Indian Point 3 Nuclear Power Plant — Amdt. 81, 6-6-88

1.1 Definitions

MODE (continued)

vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

OPERABLE-OPERABILITY

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

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in FSAR Chapter 13, Initial Tests and Operations;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

QUADRANT POWER TILT RATIO (QPTR)

QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3067.4 MWt.

3216

S

(continued)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Vessel inlet temperature, and pressurizer pressure shall not exceed the SLs limits specified in ~~Figure 2.1-1.~~ T

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, 5, and in MODE 6 when the reactor vessel head is on, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, 5, or 6, restore compliance within 5 minutes.

TSTF 339; Insert 1:

The COLR; and the following SLs shall not be exceeded: T

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained ≥ 1.17 for the WRB-1 DNB correlations.

2.1.1.2 The peak fuel centerline temperature shall be maintained < 5080°F, decreasing by 58°F per 10,000 MWD/MTU of burnup.

This curve does not provide allowable limits for normal operation.
(see LCO 3.4.1, Pressure, Temperature and Flow DNB limits, for DNB limits)

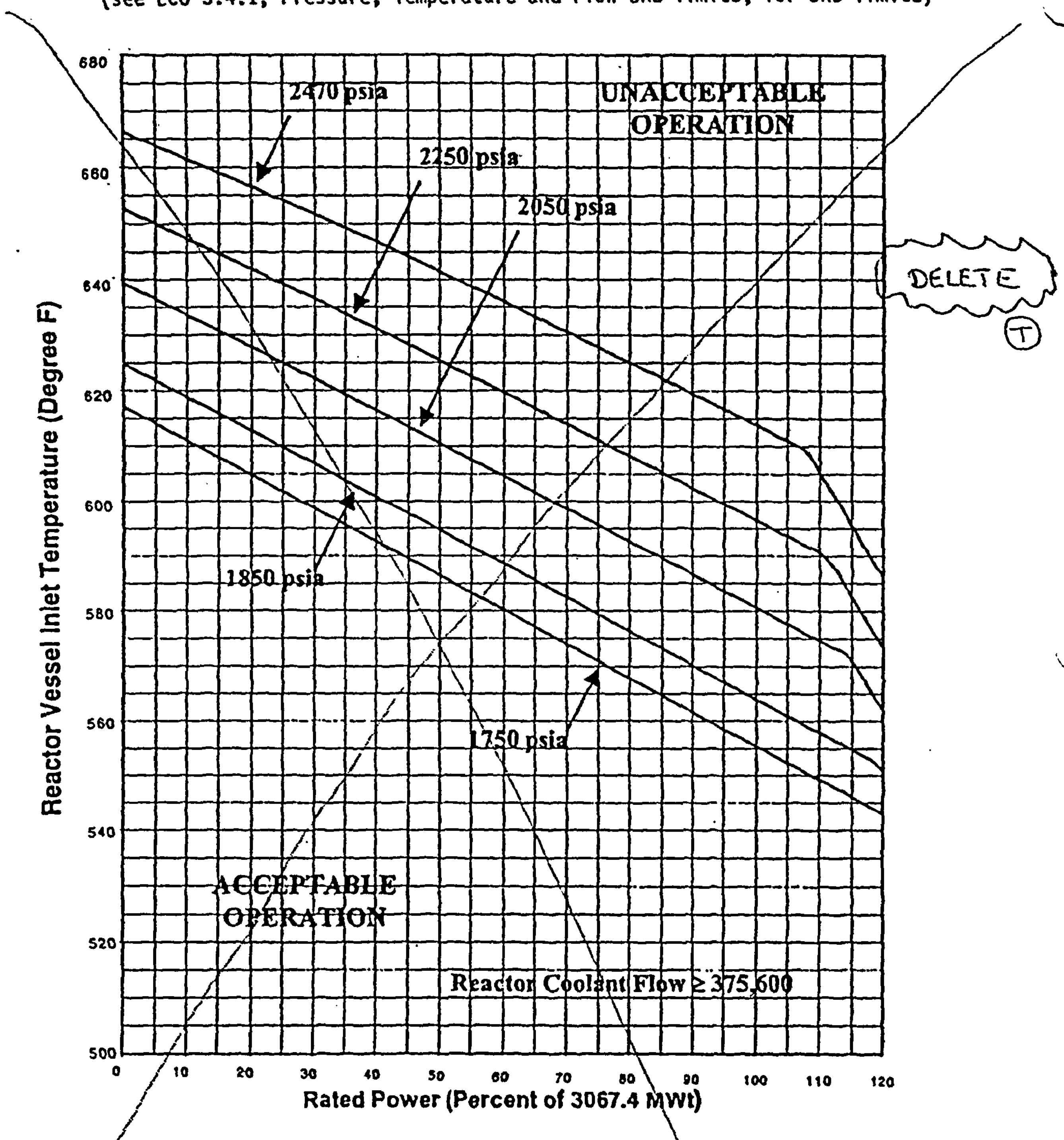


Figure 2.1-1
Rated Power (Percent of 3067.4 MWt)
100 PERCENT RATED POWER IS EQUIVALENT TO 3067.4 MWt
Pressures and temperatures do not include allowance for instrument error

Table 3.3.1-1 (page 1 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3[a], 4[a], 5[a]	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4[j]	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11	≤~~109%~~ RTP 111% X
b. Low	1[b],2	4[j]	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤25% RTP
3. Intermediate Range Neutron Flux	1[b], 2[c]	1	F	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	NA

(continued)

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(b) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(j) Only 3 channels required during Mode 2 Physics Tests, LCO 3.1.8

Table 3.3.1-1 (page 3 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Pressurizer Pressure					
a. Low	1(e)	4	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥~~1790~~ psig 1900 S
b. High	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤2400 psig
8. Pressurizer Water Level - High	1(e)	3	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤97%
9. Reactor Coolant Flow - Low	1(e)	3 per loop	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥90%

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 7 of 8)
Reactor Protection System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o [K_1 - K_2 [(1 + \tau_1 s)/(1 + \tau_2 s)] (T_{avg} - T') + K_3 (P - P') - f(\Delta I)]$$

Where: $K_1 \leq 1.285$ $K_2 = 0.0273$ $K_3 = 0.0013$

$\tau_1 \geq 25$ seconds $\tau_2 \leq 3$ seconds

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T

ΔT_o	$\leq$	Measured full power ΔT for the channel being calibrated, °F.
T_{avg}	=	Average Temperature for the channel being calibrated, °F (input from instrument racks)
s	=	Laplace transform operator, seconds^{-1}
T'	=	Measured full power T_{avg} for the channel being calibrated, °F
P	=	Pressurizer pressure, psig (input from instrument racks)
P'	=	2235 psig (i.e., nominal pressurizer pressure at rated power)

K_1 is a constant which defines the overtemperature ΔT trip margin during steady state operation if the temperature, pressure, and $f(\Delta I)$ terms are zero.

K_2 is a constant which defines the dependence of the overtemperature ΔT setpoint to T_{avg}.

K_3 is a constant which defines the dependence of the overtemperature ΔT setpoint to pressurizer pressure.

τ dynamic compensation time constants

ΔI = $q_t - q_b$, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of RTP.

$F(\Delta I)$ = 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, where q_t and q_b are defined above such that:

(a) for $q_t - q_b$ between −15.75% and +6.9%, $f(\Delta I)=0$.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +6.9%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 3.333% of RTP.

(c) or each percent that the magnitude of $q_t - q_b$ is more negative than −15.75%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 4.000% of RTP.

INSERT FOR PAGE 3.3.1-19

TSTF-339, Rev 2

Table 3.3.1-1 (page 7 of 8)
Reactor Trip System Instrumentation

Note 1: Overtemperature ΔT 2.8% (S) [Note: IP3 CLB = 5.8%]

The Overtemperature ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than ~~[3.8]%~~ of ΔT span.

CLB

$$\cancel{\Delta T \frac{(1+\tau_4 s)}{(1+\tau_5 s)}\left(\frac{1}{1+\tau_6 s}\right) \le \Delta T_0 \left\{K_1 - K_2\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[T\frac{1}{(1+\tau_6 s)} - T'\right] + K_3(P-P') - f_1(\Delta I)\right\}}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T′ is the nominal T_{avg} at RTP, ≤ ~~[588]~~ °F. [*]

P is the measured pressurizer pressure, psig
P′ is the nominal RCS operating pressure, ≤ ~~[2235]~~ psig [*]

CLB: Delete τ_3 through τ_6

$K_1 \le$ ~~[1.09]~~ [*]	$K_2 \ge$ ~~[0.0138]~~/°F [*]	$K_3 =$ ~~[0.000671]~~/psig [*]
$\tau_1 \ge$ ~~[8]~~ sec [*]	$\tau_2 \le$ ~~[3]~~ sec [*]	$\tau_3 \le$ ~~[2]~~ sec
$\tau_4 \ge$ ~~[33]~~ sec	$\tau_5 \le$ ~~[4]~~ sec	$\tau_6 \le$ ~~[2]~~ sec

$f_1(\Delta I)$ = ~~[3.5]~~{~~[23]~~ + $(q_t - q_b)$} when $q_t - q_b \le -$ ~~[23]~~% RTP
0% of RTP when $-$~~[23]~~% RTP < $q_t - q_b \le$ ~~[8]~~% RTP
~~[3.1]~~{$(q_t - q_b) -$ ~~[8]~~} when $q_t - q_b >$ ~~[8]~~% RTP

[*]

Where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

The values denoted with [*] are specified in the COLR.

$$\Delta T \le \Delta T_0 \left\{K_1 - K_2\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[T - T'\right] + K_3(P - P') - f_1(\Delta I)\right\}$$

Table 3.3.1-1 (page 8 of 8)
Reactor Protection System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \le \Delta T_o (K_4 - K_5 (dTavg/dt) - K_6(T_{avg} - T'))$$

Where:

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T

K_4 ≥ 1.154

K_5 = 0 for decreasing average temperature; and
≥ 0.175 sec/°F for increasing average temperature

K_6 = 0 for T ≤ T'; and
≥ 0.00134 for T > T'

ΔT_o ≤ measured full power ΔT for the channel being calibrated, °F

T_{avg} = measured average temperature for the channel being calibrated, °F (input from instrument racks)

T' = measured full power T_{avg} for the channel being calibrated, °F (can be set no higher than 570.3 °F)

s = Laplace transform operator, seconds

K_4 is a constant which defines the overpower ΔT trip margin during steady state operation if the temperature term is zero.

K_5 is a constant determined by dynamic considerations to compensate for piping delays from the core to the loop temperature detectors; it represents the combination of the equipment static gain setting and the time constant setting.

K_6 is a constant which defines the dependence of the overpower ΔT setpoint to T_{avg}.

dTavg/dt is the rate of change of T_{avg}

INSERT FOR PAGE 3.3.1-20

TSTF-339, Rev 2

Table 3.3.1-1 (page 8 of 8)
Reactor Trip System Instrumentation

1.8 % S [Note: IP3 CLB = 3.7%]

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than ~~[3.1%]~~ of ΔT span.

CLB

$$\Delta T \cancel{\frac{(1+\tau_1 s)}{(1+\tau_2 s)}} \cancel{\left(\frac{1}{1+\tau_3 s}\right)} \le \Delta T_0 \left\{K_4 - K_5 \cancel{\frac{\tau_7 s}{1+\tau_7 s}} \cancel{\left(\frac{1}{1+\tau_6 s}\right)} T - K_6 \left[T \cancel{\frac{1}{1+\tau_6 s}} - T''\right] - \cancel{f_2(\Delta I)}\right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T'' is the nominal T_{avg} at RTP, ≤ ~~[588]~~ °F.

$K_4 \le$ ~~[1.09]~~ *

$K_5 \ge$ ~~[0.02]~~/°F for increasing T_{avg} *
~~[0]~~/°F for decreasing T_{avg}

$K_6 \ge$ ~~[0.00128]~~/°F when T > T'' *
~~[0]~~/°F when T ≤ T''

$\tau_1 \ge$ ~~[8]~~ sec $\tau_2 \le$ ~~[3]~~ sec *
$\tau_6 \le$ ~~[2]~~ sec $\tau_7 \ge$ ~~[10]~~ sec *

$\tau_3 \le$ ~~[2]~~ sec *

$f_2(\Delta I)$ = ~~0% RTP for all ΔI~~ [*]

delete τ's not used for IP3 CLB

The values denoted with [*] are specified in the COLR.

$$\Delta T \le \Delta T_0 \left\{K_4 - K_5 \frac{\tau_7 s}{(1+\tau_7 s)} T - K_6 (T - T'') - f_2(\Delta I)\right\}$$

Table 3.3.2-1 (page 1 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure-Hi	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤4.80 psig
d. Pressurizer Pressure-Low	1,2,3[b]	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥1690 psig X 1710
e. High Differential Pressure Between Steam Lines	1,2,3	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	NA
f. High Steam Flow in Two Steam Lines	1,2[d],3[d]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}- Low	1,2[d],3[d]	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥538°F X 540.5

(continued)

(a) Not used

(b) Above the Pressurizer Pressure interlock.

(c) Less than or equal to turbine first stage pressure corresponding to 54% full steam flow below 20% load, and increasing linearly from 54% full steam flow at 20% load to 120% full steam flow at 100% load, and corresponding to 120% full steam flow above 100% load. Time delay for SI ≤6 seconds.

(d) Except when all MSIVs are closed.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation	1,2[d],3[d]	2 per steam line	F	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2[d],3[d]	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure (Hi-Hi)	1,2[d], 3[d]	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤24 psig
d. High Steam Flow in Two Steam Lines	1,2[d], 3[d]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}-Low	1,2[d], 3[d]	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥538°F 540.5 X
e. High Steam Flow in Two Steam Lines	1,2[d], 3[d]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with Steam Line Pressure-Low	1,2[d], 3[d]	1 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥500 psig

(c) Less than or equal to turbine first stage pressure corresponding to 54% full steam flow below 20% load, and increasing linearly from 54% full steam flow at 20% load to 120% full steam flow at 100% load, and corresponding to 120% full steam flow above 100% load. Time delay for SI ≤6 seconds.

(d) Except when all MSIVs are closed.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below: T

a. Pressurizer pressure ~~≥ 2205 psig~~; is greater ~~than~~ or equal to the limit specified in the COLR

b. RCS average loop temperature ~~≤ 571.5°F~~; and is less than or equal to the limit specified in the COLR T

c. RCS total flow rate ≥ ~~375,600~~ 354,400 S gpm and greater than or equal to the limit specified in the COLR. T

APPLICABILITY: MODE 1.

------------------------------NOTE------------------------------

Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limits.	2 hours
B. Required action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

greater than or equal to the limit specified in the COLR (T)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure ~~is ≥ 2205 psig~~.	12 hours
SR 3.4.1.2	Verify RCS average loop temperature is ~~≤ 571.5°F~~. less than or equal to the limit specified in the COLR (T)	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ ~~375,600~~ gpm.	12 hours
SR 3.4.1.4	-------------------NOTE------------------------ Not required to be performed until 24 hours after ≥ 90% RTP. --- Verify by precision heat balance that RCS total flow rate is ≥ ~~375,600~~ gpm.	24 months

354,400 (S)

and greater than or equal to the limit specified in the COLR (T)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with: 54.3 XS

a. ~~Actual~~ P pressurizer water level ≤ ~~58.3~~% in MODES 1 and 2 or ≤ 90% in MODE 3; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW and capable of being powered from an emergency power supply.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Pressurizer water level not within limit.	A.1	Be in MODE 3 with reactor trip breakers open.	6 hours
	AND		
	A.2	Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1	Restore required group of pressurizer heaters to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1 54.3	Verify ~~actual~~ pressurizer water level is ≤ ~~58.3~~% in MODES 1 and 2 <u>OR</u> ≤ 90% in MODE 3.	12 hours x S
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	24 months

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Applicable Neutron Flux Trip Setpoint in Percent of RATED THERMAL POWER

MINIMUM NUMBER OF MSSVs PER STEAM GENERATOR REQUIRED OPERABLE	APPLICABLE Neutron Flux Trip Setpoint (% RTP)
4	≤ ~~60~~ 57
3	≤ ~~41~~ 38
2	≤ ~~22~~ 20

S

5.5 Programs and Manuals

5.5.15 Containment Leakage Rate Testing Program (continued)

cooler unit when pressurized at ≥ 1.1 Pa. This limit protects the internal recirculation pumps from flooding during the 12-month period of post accident recirculation.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10CFR50, Appendix J.

~~The peak calculated containment internal pressure for the design basis main steam line break, Pa, is 42.40 psig. The minimum test pressure is 42.42 psig.~~

The maximum allowable primary containment leakage rate, La, at Pa, shall be 0.1% of primary containment air weight per day.

5

The calculated peak containment internal pressure for the design basis loss of coolant accident, Pa, is 42.0 psig. The containment design pressure is 47 psig.

5.6 Reporting Requirements

T

1. Specification 2.1, Safety Limits (SL);

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

2. ~~1.~~ Specification 3.1.1, Shutdown Margin;

3. ~~2.~~ Specification 3.1.3, Moderator Temperature Coefficient;

4. ~~3.~~ Specification 3.1.5, Shutdown Bank Insertion Limits;

5. ~~4.~~ Specification 3.1.6, Control Bank Insertion Limits;

6. ~~5.~~ Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z));

7. ~~6.~~ Specification 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor;

8. ~~7.~~ Specification 3.2.3, AXIAL FLUX DIFFERENCE (AFD); and

11. ~~8.~~ Specification 3.9.1, Boron Concentration.

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

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary). (Specifications 3.1.5, Shutdown Bank Insertion Limits, 3.1.6, Control Bank Insertion Limits, and 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor);

2a. WCAP-8385, "POWER DISTRIBUTION CONTROL AND LOAD FOLLOWING PROCEDURES, TOPICAL REPORT," September 1974 (W Proprietary). (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control);

2b. T. M. Anderson to K. Kneil (Chief of Core Performance Branch, NRC) January 31, 1980 -- Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package. (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control));

2c. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch

9. Specification 3.3.1, Reactor Protection System Instrumentation;

10. Specification 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits; and

T

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981. (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control));

3a. WCAP-12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1), "Code Qualification Document for Best-Estimate Loss-of-Coolant-Accident Analysis," March 1998 (Westinghouse Proprietary);

3b. ~~NOT USED~~ insert 3b T

3c. ~~NOT USED~~ insert 3 c T

insert 3e X

3d. WCAP-10054-P-A, "SMALL BREAK ECCS EVALUATION MODEL USING NOTRUMP CODE," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z));

3f. ~~3e.~~ WCAP-10079-P-A, "NOTRUMP NODAL TRANSIENT SMALL BREAK AND GENERAL NETWORK CODE," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z))); and

3g. ~~3f.~~ WCAP-12610, "VANTAGE+ Fuel Assembly Report," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor).

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided for each reload cycle to the NRC.

5.6.6 NOT USED

INSERTS FOR PAGE 3.0-35 (SECTION 5.6.5.b)

Insert 3.b:

3.b WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989 (Specification 2.1, Safety Limits (SL) and Specification 3.4.1, (RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits);

Insert 3.c:

3.c WCAP-8745-P-A, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986 (Specification 2.1, Safety Limits (SL));

Insert 3.e:

3.e WCAP-10054-P-A, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code; Safety Injection into the Broken Loop and Cosi Condensation Model," July 1997 (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z)));

BASES

BACKGROUND (continued)

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

RCS Flow, ΔI,

The Reactor Protection System (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

appropriate operation of the RPS and steam generator safety valves.

Automatic enforcement of these reactor core SLs is provided by the ~~following functions:~~

~~a. High pressurizer pressure trip;~~

~~b. Low pressurizer pressure trip;~~

~~c. Overtemperature ΔT trip;~~

~~d. Overpower ΔT trip;~~

~~e. Power Range Neutron Flux trip; and~~

~~f. Steam generator safety valves.~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the ΔT measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

figure

the COLR

The ~~curves~~ provided in ~~Figure 2.1-1~~ show s the loci of points of thermal power, Reactor Coolant System pressure and vessel inlet temperature for which the calculated DNBR is no less than the Safety Limit DNBR value or the average enthalpy at the vessel exit is less than the enthalpy of saturated liquid.

TSTF 339
INSERT 2

The calculation of these limits assumes:

1. $F_{\Delta H}^{RTP} = F_{\Delta H}^{N}$ limit at RTP specified in the COLR;

2. An equivalent average steam generator tube plugging level of ~~up to 30% in any steam generator provided the equivalent average plugging level in all steam generators is~~ less than or equal to ~~24% (Ref. 3)~~ 10%;

3. Reactor coolant system total flow rate of greater than or equal to ~~375,600~~ 364,700 gpm as measured at the plant; and,

4. A reference cosine with a peak of 1.55 for axial power shape.

The figure in the COLR

~~Figure 2.1-1~~ includes an allowance for an increase in the enthalpy rise hot channel factor at reduced power based on the expression:

(continued)

TSTF-339, INSERT 2

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and that the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

BASES

SAFETY LIMIT VIOLATIONS

If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable. The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Section 7.2.

3. ~~WCAP-10705, Safety Evaluation for Indian Point Unit 3 with Asymmetric Tube Plugging Among Steam Generators, October 1984.~~

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

INSERT A HERE

~~The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.~~

INSERT B HERE

~~The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope. RCS average loop temperature is assumed to be the highest indicated value of the Tavg indicators and this is the value that is compared to the acceptance criteria. A higher average temperature will cause the core to approach DNB limits.~~

INSERT C HERE

~~The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. RCS flow rate is determined by calculating the average flow rate for each loop and then calculating the sum of these average loop flow rates and this sum of the averages is compared to the acceptance criteria. A lower RCS flow will cause the core to approach DNB limits.~~

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

(continued)

BASES

BACKGROUND (continued)

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

TSTF INSERT X

LCO

This LCO specifies limits on the monitored process variables (i.e., pressurizer pressure, RCS average loop temperature, and RCS total flow rate, to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

TSTF INSERT Y

INSERT D HERE

~~The RCS total flow rate limit of 375,600 gpm allows a measurement uncertainty of 2.9% associated with the performance of Reactor coolant System Flow Calculation.~~

INSERT E HERE

~~The pressurizer pressure limit of 2205 psig includes the allowance for measurement uncertainty and instrument error. The limit on RCS average loop temperature provides assurance that RCS temperatures are maintained within the normal steady state envelope of operation assumed in the safety analyses performed to~~

(continued)

BASES

LCO (continued)

INSERT F HERE

~~support the Vantage + fuel reloads with asymmetric tube plugging among steam generators. A maximum full power Tcold of 547.7°F (including control deadband and measurement uncertainties) was assumed in these safety analyses. A Tavg of 578.3°F assures that a Tcold of 547.7°F is not exceeded at a measured flow of ≥ 375,600 gpm when considering asymmetric tube plugging among steam generators for DNB considerations. Therefore, the LCO limit of 571.5°F for RCS average loop temperature, which is based on meeting analysis assumptions for post LOCA containment integrity, conservatively ensures that DNBR limits are met.~~

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit

~~Another set of limits on DNB related parameters~~ is provided in SL 2.1.1, "Reactor Core SLs." ~~Those limits~~ are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

The conditions which define the DNBR limit

(continued)

INSERTS FOR
Bases 3.4.1
(page 1 of 2)

Uprate Insert A

The RCS pressure limit is consistent with operation within the nominal operational envelope and controlling to 2235 psig. Pressurizer pressure indications are averaged to provide a value for comparison to the limit. The indicated limit is based on the average of three control board readings. A lower pressure will cause the reactor core to approach DNB limits.

Insert B

The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope and controlling to a full power Tavg of 572.0 °F. RCS average loop temperature is assumed to be the highest indicated value of the Tavg indicators and this value is compared to the limit. The indicated limit is based on the average of three control board readings. A higher average temperature will cause the core to approach DNB limits.

Insert C

The RCS f low rate normally remains constant during an operational fuel cycle with all. pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analysis. For the 24-month surveillance, RCS flow rate is determined by performing a heat balance after each refueling at ≥ 90% RTP, calculating the flow rate for each RCS loop, calculating the sum of these loop flow rates, and the sum is compared to the limit. For the 12-hour surveillance, RCS flow rate is determined from the average of the loop flow indications on each RCS loop, calculating the sum of these loop flow rates, and the sum is compared to the limit. The indicated limit is based on the average of two control board readings per RCS loop. A lower RCS flow rate will cause the core to approach DNB limits.

TSTF INSERT X

The pressurizer pressure limit and RCS average temperature limit specified in the COLR are based on the analytical limits used in the safety analyses. Therefore, appropriate allowances for measurement and instrument uncertainty must be included when comparing the observed value with the analytical limits.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

TSTF INSERT Y

These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, which is based on maximum analyzed steam generator tube plugging, is retained in the TS LCO.

INSERTS FOR
Bases 3.4.1
(page 2 of 2)

Insert D

The RCS flow rate limit of 364,700 gpm allows a measurement uncertainty of 2.9% associated with the average of two control board readings per RCS loop. A thermal design flow of 354,400 gpm and a minimum measured flow of 364,700 gpm (including measurement uncertainty) are assumed in the safety analysis. The control board loop RCS flow indications are normalized to the heat balance RCS loop flow measurements after each refueling.

Insert E

The pressurizer pressure limit of 2204 psig allows for a measurement uncertainty of 24 psig associated with the average of three control board readings. A minimum value of 2180 psig (including control and measurement uncertainties) is assumed in the safety analysis.

Insert F

The RCS average loop temperature limit of 576.3 deg-F allows for a measurement uncertainty of 3.2 deg-F associated with the average of three control board readings. A maximum full power Tavg of 579.5 deg-F (including control deadband and measurement uncertainties) is assumed in the safety analysis. 579.5 deg-F in the safety analysis corresponds to a maximum Tavg control value of 572.0 deg-F.

BASES

BACKGROUND (continued)

margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480V vital buses as follows: bus 2A (DG 31) supports 485 kW of pressurizer heaters; bus 3A (DG 31) supports 555 kW of pressurizer heaters; bus 5A (DG 33) supports 485 kW of pressurizer heaters; and, bus 6A (DG 32) supports 277 kW of pressurizer heaters.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. For events that result in pressurizer insurge (e.g., loss of normal feedwater, loss of offsite power and loss of load/turbine trip), the analyses assume that the limiting value for the highest initial pressurizer level is 59.3%. This analytical limit is based on the pressurizer program level of 50.8% at a full power Tavg 572°F plus a conservative 8.5% of span. For other events, the nominal value of pressurizer level is assumed because the effect of the initial pressurizer level on the results is small. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. ~~The required pressurizer level of ≤ 50.3% is the analytical limit used as an initial condition in the accident analysis. An additional margin should be allowed for instrument error.~~

Safety analyses presented in the FSAR (Ref. 1) that are examined for pressurizer filling, the loss of normal feedwater and loss of offsite power analyses, assume ~~do not take credit for~~ pressurizer heater operation, as operation of the heaters makes the transient results more limiting by contributing to the thermal expansion of the water in the pressurizer. ~~; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.~~

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36. ~~Although the heaters are not specifically used in accident analysis, the~~ The need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

(continued)

BASES (continued)

LCO

INSERT G HERE

~~The LCO requirement for the pressurizer to be OPERABLE with water level less than or equal to 58.3%, ensures that a steam bubble exists. The required pressurizer level of ≤ 58.3% is the analytical limit used as an initial condition in the accident analysis. An additional margin of approximately 7% should be allowed for instrument error (i.e., the indicated level should not exceed 51.3%).~~

Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. Each of the 2 groups of pressurizer heaters should be powered from a different DG to ensure that the minimum required capacity of 150 kW can be energized during a loss of offsite power condition assuming the failure of a single DG. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW is sufficient to maintain pressure and is dependent on the heat losses.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an

(continued)

Insert G (page B 3.4.9-3)

The pressurizer water level limit is consistent within the nominal operational envelope and controlling to 50.8% level span at a full power Tavg of 572.0°F. The pressurizer water level must be ≤ 54.3% for the pressurizer to be OPERABLE and will ensure that a steam bubble exists. Pressurizer water level indications are averaged to provide a value for comparison to the limit. The indicated limit is based on the average of two control board readings, and allows for a measurement uncertainty of 5%.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat) in Mwt (i.e. 3230 Mwt);

Deleted: 3081.4

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

ws = Minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure, including tolerance and accumulation, as appropriate, in lb/sec. (ws = 150 + 228.61 * (4 - V) lb/sec, where V = Number of inoperable safety valves in the steam line of the most limiting steam generator).

h_{fg} = Heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm (i.e.,608.5 Btu/lbm).

N = Number of loops in plant (i.e., 4).

The calculated reactor trip setpoint is further reduced by 9% of full scale to account for instrument uncertainty and then rounded down.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

The accident analysis requires five MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 102% RTP. An MSSV will be considered inoperable if it fails to open on demand. The LCO requires that five MSSVs be OPERABLE in compliance with Reference 2. This is because operation with less than the full number of MSSVs requires limitations on allowable THERMAL POWER (to meet ASME Code requirements). These limitations are according to Table 3.7.1-1 in the accompanying LCO, and Required Action A.1.

Deleted: 100.6

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced.

(continued)

BASES

LCO (continued)

The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

The lift settings, according to Table 3.7.1-2 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB.

APPLICABILITY

In MODE 1 above ~~23%~~ 20% RTP, the number of MSSVs per steam generator required to be OPERABLE must be according to Table 3.7.1-1 in the accompanying LCO. Below ~~23%~~ 20% RTP in MODES 1, 2, and 3, only two MSSVs per steam generator are required to be OPERABLE.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1

Startup and power operation with up to three of the five MSSVs associated with each steam generator inoperable is permissible if the maximum allowed power level is below the heat removing capability of the operable MSSVs. Therefore, startup and power operation with inoperable main steam line safety valves is allowable if the neutron flux trip setpoints are restricted within the limits specified in Table 3.7.1-1. This ensures that reactor power level is limited so that the heat input from the primary side will not exceed the heat removing capability of the OPERABLE MSSVs of the most limiting steam generator.

(continued)

ATTACHMENT III TO NL-04-069

WCAP-16212-P (Proprietary)

Indian Point Nuclear Generating Unit No. 3
Stretch Power Uprate
NSSS and BOP Licensing Report

NOTE: Attachment III report is not included with packages for non-proprietary distribution. WCAP-16212-NP (Non-Proprietary) is provided in lieu of Attachment III

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

ENCLOSURES TO NL-04-069

A. Westinghouse authorization letter dated June 1, 2004 (CAW-04-1841), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice

B. WCAP-16212-NP, "Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report," dated May 2004. (Non-Proprietary)

Enclosure B is included in lieu of Attachment III for packages issued to non-proprietary distribution.

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

Westinghouse

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

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

Direct tel: (412) 374-4643
Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-04-1841

June 1, 2004

APPLICATION FOR WITHHOLDING PROPRIETARY INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-16212-P, "Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-04-1841 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Entergy Nuclear Operations.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-04-1841, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: W. Macon
E. Peyton

CAW-04-1841

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

PATRICIA L. CROWN COMMONWEALTH OF PENNSYLVANIA NOTARY PUBLIC

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 1st day
of June, 2004

Patricia L. Crown
Notary Public

Notarial Seal
Patricia L. Crown, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Feb. 7, 2005
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-16212-P, "Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report" (Proprietary) dated June 2004, being transmitted by the Entergy Nuclear Northeast letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for the Indian Point Nuclear Generating Unit No. 3 is expected to be applicable for other licensee submittals in response to certain NRC requirements for justification of Stretch Power Uprate License Amendment Request.

This information is part of that which will enable Westinghouse to:

(a) Provide information in support of plant power uprate licensing submittals.

(b) Provide plant specific calculations.

(c) Provide licensing documentation support for customer submittals.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of meeting NRC requirements for licensing documentation associated with power uprate licensing submittals.

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculations, evaluations, analyses and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

Westinghouse Non-Proprietary Class 3

WCAP-16212-NP

June 2004

Indian Point Nuclear Generating Unit No. 3

Stretch Power Uprate NSSS and BOP Licensing Report

Westinghouse Non-Proprietary Class 3

WCAP-16212-NP

Indian Point Nuclear Generating Unit No. 3

Stretch Power Uprate NSSS and BOP Licensing Report

J. R. Stukus
Westinghouse Nuclear Services

T. F. Timmons
Westinghouse Nuclear Services

T. J. Gerlowski
Westinghouse Nuclear Services

P. Cafarella
Stone and Webster Engineering Corporation

M. Scanlon
Stone and Webster Engineering Corporation

June 2004

Westinghouse Electric Company LLC
P.O. Box 355
Pittsburgh, PA 15230-0355

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LIST OF ACRONYMS

1-D	one-dimensional
2-D	two-dimensional
3-D	three-dimensional
AAC	alternate AC
ACI	American Concrete Institute
AEC	Atomic Energy Commission
AFW	auxiliary feedwater
AFWS	Auxiliary Feedwater System
AISC	American Institute of Steel Construction
ALARA	as-low-as-is-reasonably-achievable
AMSAC	ATWS mitigating system actuation circuitry
ANC	Advanced Nodal Code
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOR	Analysis of Record
AOV	air-operated valve
ART	adjusted reference temperature
ARV	atmospheric relief valve
ASD	after shutdown
ASME	American Society of Mechanical Engineers
ASSS	Alternate Safe Shutdown System
AST	alternative source term
ATWS	anticipated transient without scram
AV	allowable value
AVB	anti-vibration bar
B&PV	boiler and pressure vessel
BELBLOCA	best-estimate large-break loss-of-coolant accident
BFRV	bypass feedwater regulator valve
bhp	brake horsepower

LIST OF ACRONYMS (Cont.)

BMI	bottom-mounted instrumentation
BOC	beginning of cycle
BOL	beginning of life
BOP	balance of plant
BOT	break opening time
BRS	Boron Recycle System
Btu	British thermal unit
C&FS	Condensate and Feedwater System
CAOC	constant axial offset control
CBP	condensate booster pump
CCR	central control room
CCW	component cooling water
CCWS	Component Cooling Water System
CDF	core damage frequency
CEDE	committed effective dose equivalent
CFD	computational fluid dynamics
CFR	Code of Federal Regulations
CIV	containment isolation valve
CLH	capped latch housing
CLOF	complete-loss-of-flow
CLOF-UF	complete-loss-of-flow under frequency
CN	calculation note
COLR	*Core Operating Limit Report*
COMS	Cold Overpressure Mitigation System
CP	condensate pump
CPS	Condensate Polishing System
CR	containment recirculation
CRDM	control rod drive mechanism
CS	containment spray

LIST OF ACRONYMS (Cont.)

CSA	channel statistical allowance
CSS	Containment Spray System
CST	condensate storage tank
CU	channel uncertainty
CUF	cumulative usage factor
Cv	valve flow coefficient
CVCS	Chemical and Volume Control System
CW	circulating water
CWIT	circulating water inlet temperature
CWS	Circulating Water System
DBA	design basis accident
DBE	design basis earthquake
DCF	dose conversion factor
DCP	design change package
DDE	deep dose equivalent
DE	dose equivalent
DECL	double-ended cold leg
DEHL	double-ended hot leg
DEPS	double-ended pump suction
DER	double-ended rupture
DF	decontamination factor
DG	diesel generator
DGV	degraded grid voltage
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DOR	Division of Operating Reactors
dpa	displacement of atom
DSS	Diverse Scram System

LIST OF ACRONYMS (Cont.)

DW	Direct Work Item
EAB	exclusion area boundary
EBOP	emergency bearing oil pump
ECCS	Emergency Core Cooling System
EDE	effective dose equivalent
EDG	emergency diesel generator
EFPY	effective full-power year
EM	evaluation model
EOC	end of cycle
EOL	end of life
EOP	Emergency Operating Procedure
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPT	electrical penetration tunnel
EPU	extended power uprate
EQ	environmental qualification
ERG	Emergency Response Guideline
ES	extraction steam
ESF	engineered safety feature
ESFAS	Engineered Safety Feature Actuation System
ESOP	emergency seal oil pump
ESS	Extraction Steam System
ET	electric tunnel
ETAP	Electrical Transient Analyzer Program
FAC	final acceptance criteria
FAC	flow-accelerated corrosion
FACP	Flow Accelerated Corrosion Program
FCEP	Fuel Criteria Evaluation Process
FCU	fan cooling unit

LIST OF ACRONYMS (Cont.)

FCV	feedwater control valve
FDB	flow distribution baffle
FES	Final Evaluation Statement
FHA	fuel-handling accident
FHB	Fuel-Handling Building
FIV	feedwater isolation valve
FIV	flow-induced vibration
FLB	feedwater line break
F_N	Froude Number
FOA	fans, oil, and air
FPPP	Fire Protection Program Plan
FQ	peaking factor
FRV	feedwater regulator valve
FSAR	Final Safety Analysis Report
FU	fuel upgrade
FWH	feedwater heater
FWI	feedwater isolation
FWIV	feedwater isolation valve
FWS	Feedwater System
GDC	General Design Criteria
GDT	gas decay tank
GI	Generic Issue
GL	Generic Letter
GSI	Generic Safety Issue
GSS	Gland Steam System
GWDS	Gaseous Waste Disposal System
HD	heater drain pump
HEI	Heat Exchange Institute, Inc.
HELB	high-energy line break

LIST OF ACRONYMS (Cont.)

HFF	hydraulic forcing function
HFP	hot full power
HHSI	high-head safety injection
HHSIS	High-Head Safety Injection System
HLSO	hot-leg switchover
hp	horsepower
HP	high pressure
HT	holdup tank
HVAC	heating, ventilation, and air conditioning
HZP	hot zero power
I&C	instrumentation and control
ICH	in-core hold
ID	inside diameter
IFBA	integral fuel burnable absorber
IFM	intermediate flow mixing
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test
IP1	Indian Point Unit 1
IP2	Indian Point Unit 2
IP3	Indian Point Unit 3
IPB	Iso-Phase bus
ISI	in-service inspection
ISLH	in-service leak and hydrostatic
ISONE	Independent System Operator New England
IST	in-service testing
ITS	Improved Technical Specifications
K_{eff}	effective multiplication factor
K_I	stress intensity factor
K_{IC}	critical value of K_I, or fracture toughness

K_{IR}	reference stress intensity factor
LAR	Licensing Amendment Request
LBB	leak-before-break
LBLOCA	large-break loss-of-coolant accident
LCV	level control valve
LEFM	linear elastic fracture mechanics
LERF	large early release frequency
LHF	LOCA hydraulic force
LHSI	low-head safety injection
LHSIS	Low-Head Safety Injection System
LOAC	loss-of-AC power
LOCA	loss-of-coolant accident
LOCA RV/RI	LOCA reactor vessel/reactor internal
LOL	loss-of-load
LONF	loss of normal feedwater
LOOP	loss-of-offsite power
LP	low pressure
LPP	low-pressurizer pressure
LPZ	low-population zone
LTOP	low-pressure overpressure protection
LTOPS	Low-Pressure Overpressure Protection System
LWPS	Liquid Waste Processing System
LWR	light water reactor
M&E	mass and energy
MA	mill-annealed
MBFP	main boiler feed pump
m/c	measurement/calculation
MCO	moisture carryover

LIST OF ACRONYMS (Cont.)

MDAFWP	motor-driven auxiliary feedwater pump
MFIV	main feedwater isolation valve
MFP	main feedwater pump
MFWV	main feedwater valve
MMF	minimum measured flow
MOC	middle of cycle
MOL	middle of life
MOP	moisture pre-separator
MOV	motor-operated valve
MS	main steam
MSIV	main steam isolation valve
MSLB	main steamline break
MSR	moisture separator reheater
MSS	Main Steam System
MSSV	main steam safety valve
MT	main transformer
MTC	moderator temperature coefficient
MTU	metric ton unit
MUR	measurement uncertainty recapture
NDE	nondestructive examination
NEC	National Electric Code
NEMA	National Electric Manufacturer's Association
NIS	Nuclear Instrumentation System
NPCC	Northeast Power Coordinating Council
NPSH	net positive suction head
NPSHA	net positive suction head, actual
NPSHR	net positive suction head, required
NR	narrow range
NRC	Nuclear Regulatory Commission

LIST OF ACRONYMS (Cont.)

NRS	narrow range span
NSSS	Nuclear Steam Supply System
NTS	nominal trip setpoint
NUMARC	Nuclear Management and Resource Council
NUPPSCO	Nuclear Power Plant Standards Committee
NUS	Nuclear Utilities Service
NYISO	New York Independent System Operator
NYPA	New York Power Authority
OBE	operating basis earthquake
OD	outside diameter
ODSCC	outer diameter stress corrosion cracking
OEM	Original Equipment Manufacturer
OFA	optimized fuel assembly
OL	Operating License
OPS	Overpressure Protection System
OPΔT	overpower ΔT
OTΔT	overtemperature ΔT
P&I	proportional and integral
PAB	Primary Auxiliary Building
PAOT	post accident operability time
PCT	peak clad temperature
PCWG	Performance Capability Working Group
PICS	Plant Integrated Computer System
PJM	Pennsylvania-Jersey-Maryland
PLOF	partial-loss-of-flow
PICS	Plant Integrated Computer System
PORV	power-operated relief valve
POV	power-operated valve

LIST OF ACRONYMS (Cont.)

PRT	pressurizer relief tank
PSA	Probabilistic Safety Assessment
PSE&G	Public Service Electric & Gas
PSS	Primary Sampling System
PSV	pressurizer safety valve
P-T	pressure-temperature
PTS	pressurized thermal shock
PU	power uprate
PVC	polyvinyl chloride
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
PWST	primary water storage tank
PZR	pressurizer
QA	Quality Assurance
RAI	Request for Additional Information
RAT	reserve auxiliary transformer
RCCA	rod control cluster assembly
RCDT	reactor coolant drain tank
RCFC	reactor containment fan cooler
RCL	reactor coolant loop
RCP	reactor coolant pump
RCS	Reactor Coolant System
RCSES	Reactor Coolant System equipment support
RG	Regulatory Guide
RHR	residual heat removal
RHRS	Residual Heat Removal System
RI	reactor internals
RPS	Reactor Protection System
RPV	reactor pressure vessel

RSAC	Reload Safety Analysis Checklist
RSE	Reload Safety Evaluation
RSG	replacement steam generator
RTD	resistance temperature detector
RTDP	Revised Thermal Design Procedure
RT_{NDT}	reference temperature nil ductility temperature
RTP	rated thermal power
RT_{PTS}	reference temperature-pressurized thermal shock
RTS	Reactor Trip System
RV	reactor vessel
RVHP	reactor vessel head penetration
RWST	refueling water storage tank
S&W	Stone and Webster
SAL	safety analysis limit
SAT	station auxiliary transformer
SB	site boundary
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SBV	Shield Building ventilation
SCC	stress corrosion cracking
SCRUP	special crossunder pipe separator
SENY	Southeast New York
SER	*Safety Evaluation Report*
SFP	spent fuel pit
SFPCS	Spent Fuel Pit Cooling System
SG	steam generator
SGBS	Steam Generator Blowdown System
SGR	steam generator replacement
SGTP	steam generator tube plugging

LIST OF ACRONYMS (Cont.)

SGTR	steam generator tube rupture
SI	safety injection
SIS	Safety Injection System
SJAE	steam jet air ejector
SLI	steamline isolation
SP	separator parameter
SPDES	State Pollutant Discharge Elimination System
SPU	stretch power uprate
SRIS	System Reliability Impact Study
SRP	Standard Review Plan
SRSS	square root sum of the squares
SRST	spent resin storage tank
SSE	safe shutdown earthquake
STDP	Standard Thermal Design Procedure
SW	service water
SWGR	switchgear room
SWPC	Siemens-Westinghouse Power Corporation
SWS	Service Water System
TA	total allowance
T_{avg}	average temperature
T_{cold}	cold leg temperature
TDAFWP	turbine-driven auxiliary feedwater pump
TDF	thermal design flow
TDH	total discharge head
TEDE	total effective dose equivalent
TGSCC	transgranular stress corrosion cracking
T_{hot}	hot leg temperature

LIST OF ACRONYMS (Cont.)

TID	Technical Information Document
TMI	Three Mile Island
t_{min}	tube wall thickness minimum
t_{nom}	tube wall thickness nominal
TOI	Temporary Operation Instruction
T_{ref}	reference temperature
T_{sat}	water at pressurizer temperature or saturation temperature
TSP	trisodium phosphate
TSP	tube support plate
T_{steam}	steam temperature
UAT	unit auxiliary transformer
UFSAR	*Updated Final Safety Analysis Report*
UHS	ultimate heat sink
UHTR	upper head temperature reduction
USE	upper shelf energy
UT	ultrasonic testing
WBS	Work Breakdown Structure
VCT	volume control tank
WCAP	Westinghouse Commercial Atomic Power

1.0 INTRODUCTION

1.1 Background

Entergy Nuclear Operations, Inc. is requesting that the NRC review and approve an increase of approximately 4.85 percent in the licensed rated core thermal power from 3067.4 to 3216 MWt.

The stretch power uprate (SPU) is planned to occur over different refueling outages because of modifications that have to be performed to achieve 3216 MWt. Entergy plans to initially operate at a power level less than 4 percent above the current power level until secondary side plant modifications or evaluations have been completed to support power operations up to 3216 MWt.

Phase 1 will be accomplished following the upcoming refueling outage, with modifications to the high-pressure (HP) turbine and moisture separator reheaters to a power level less than 4 percent above the current power level. This power level is based on current design limitations of the low-pressure (LP) turbine.

Phase 2 of the uprate will be based on future economic decisions relating to modifications to the LP turbines and cooling for the generator and iso-phase bus (IPB) ducts. Section 1.5 of this document contains the potential list of modifications that could be required to achieve 3216 MWt.

This report summarizes the various analyses and evaluations of the potential effects of the SPU on plant systems, components, and analyses.

1.1.1 Uprate Power Level

IP3 was originally licensed to operate with a rated core thermal power of 3025 MWt. The current IP3 operating license issued by the NRC is for a rated reactor core power of 3067.4 MWt, based on the recently approved 1.4-percent measurement uncertainty recapture (MUR) uprate (Reference 1).

The IP3 engineered safety features (ESFs) were designed to accommodate the conditions associated with a rated core thermal power of 3216.5 MWt, which is above the original licensed core thermal power (3025 MWt) and above the current licensed core thermal power (3067.4 MWt).

Continuing industry improvements in analytical techniques, instrument measurement accuracies, plant thermal performance, and fuel and core designs have resulted in increased margins between the safety analyses results and the licensing limits. These industry improvements, combined with the margins in the as-designed equipment, system, and component capabilities, and margins in the current safety analyses, provide IP3 with the opportunity to increase the current licensed core thermal power rating of 3067.4 to 3216 MWt (an increase of 4.85 percent) with no significant increase in the hazards presented by the plant as currently licensed by the NRC.

This was confirmed prior to full initiation of the SPU when Entergy Nuclear Operations, Incorporated (Entergy) completed a feasibility and scoping study with the support of Westinghouse Electric Company LLC (Nuclear Steam Supply System), Stone & Webster (balance of plant), and the Siemens-Westinghouse Power Corporation (high-pressure turbine).

1.1.2 References

1. Entergy Nuclear Operations, Incorporated, *Indian Point Nuclear Generating Unit No. 3, 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, May 2002. (Approved in License Amendment 213 on November 26, 2002.)

1.2 Licensing Approach

1.2.1 Introduction

The NRC defines three categories of power uprates:

- Measurement uncertainty recapture (MUR) power uprates
- Stretch power uprates (SPUs)
- Extended power uprates (EPUs)

MUR power uprates are less than 2 percent. SPUs are typically up to 7 percent, and EPUs are greater than SPUs, and have been submitted to the NRC for increases as high as 20 percent.

The IP3 SPU represents a licensed core power level increase of 4.85 percent. This level of uprate is more than what is typically considered for an MUR power uprate (NRC guidance in Regulatory Issue Summary [RIS] 2002-03, *Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications*, January 31, 2002 [Reference 1]), but is less than the 7-percent threshold defined by the NRC as the lower bound for EPU according to RS-001, (Reference 2) NRC guidance for review of EPUs. The NRC has not yet issued guidance pertaining to SPU programs. Therefore, this application incorporates appropriate elements of both the NRC MUR and EPU guidance documents.

While RIS 2002-03 (Reference 1) (MUR guidance) does not specifically apply to the 4.85-percent IP3 SPU, this report has been structured to clearly distinguish affected and unaffected plant systems, components, and analyses. Affected systems, components, and safety analyses are those having current design and licensing bases analyses and calculations that do not bound the potential effects of the SPU. Unaffected systems, components, and safety analyses are those having current design and licensing bases analyses and calculations that bound the potential effects of the SPU. This report also identifies whether affected plant systems, components, and analyses were addressed through analysis or engineering evaluation.

While RS-001 (Reference 2) (EPU guidance) does not explicitly apply to the 4.85-percent IP3 SPU, significant detail has been provided for the analyses and evaluations of affected systems, components, and analyses. In particular, more detail has been provided for the safety analyses since many of these analyses have been revised to address the increased power level, or revised to amend inputs and parameters to provide additional margin for operations. Also, this report is based upon the consideration of the EPU guidance regarding the scope of NRC's review, and information expected in a power uprate application as discussed in the RS-001 (Reference 2).

The subject matter and detail of this report exceeds that corresponding to the MUR guidance for power uprate. The full scope of this project was jointly established by Entergy, Westinghouse, Stone & Webster (S&W), and Siemens-Westinghouse Power Corporation (SWPC) as part of an extensive planning effort. That planning effort included the development of a comprehensive Work Breakdown Structure (WBS). The planning team used experience from previous uprate projects to support the development of the WBS. The specific requirements needed to fulfill each work package within that WBS were also defined and assigned to ensure that all necessary work was accomplished. Furthermore, the SPU also incorporated responses to previous NRC Requests for Additional Information (RAIs) that have been issued for other previous uprates. To aid in the review of this Licensing Report, Table 1-1 provides a cross-reference of sections of this report with topical review areas for the various NRC review branches. As an additional aid in reviews, Table 1-2 provides information regarding:

- Whether Licensing Report sections were affected or unaffected by the SPU (according to the definitions of Reference 1).
- The method of SPU reconciliation (whether the SPU revised the analysis of record or evaluated the SPU effect on the analysis of record).
- Whether there was a change to the current design or licensing basis acceptance criteria.

Furthermore, Westinghouse has addressed the potential effects of the SPU on Nuclear Steam Supply System (NSSS) systems, components, and safety analyses consistent with the Westinghouse methodology established in WCAP-10263 (Reference 3). Since its submittal to the NRC, the WCAP-10263 methodology has been successfully used as the basis for power uprate projects for over 30 pressurized water reactor (PWR) units.

The methodology in WCAP-10263 (Reference 3) establishes the general approach and criteria for uprate projects, including the broad categories that must be addressed, such as NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel, as well as the interfaces between the NSSS and balance-of-plant (BOP) systems. The methodology includes the use of well-defined analysis input assumptions and parameter values, use of currently approved analytical techniques, and use of currently applicable licensing criteria and standards. A comprehensive engineering review program consistent with the WCAP-10263 (Reference 3) methodology has been performed for IP3 to evaluate the increase in the licensed core power from 3067.4 to 3216 MWt.

1.2.2 References

1. NRC RIS-2002-03, *Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications*, January 31, 2002.

2. NRC RS-001 (Draft), *Review Standard for Extended Power Uprates*, December 2002.

3. WCAP-10263, *A Review Plan for Uprating the Licensed Power of a PWR Power Plant*, January 1983.

1.3 Scope Summary and Application Report Structure

In support of the IP3 SPU, the following principal organizations have performed major analyses and evaluations to demonstrate that IP3 will remain in compliance with applicable licensing criteria and requirements at the SPU power level.

- Entergy Nuclear Operations, Incorporated (Entergy)
- Westinghouse Electric Company LLC (Westinghouse)
- Stone & Webster (S&W)
- Siemens-Westinghouse Power Corporation (SWPC)

The scope of the above organizations is discussed in the following subsections.

1.3.1 Entergy Nuclear Operations, Incorporated

Entergy Nuclear Operations, Incorporated (Entergy) has extensive experience in owning, managing, and operating nuclear power plants. Entergy has site resources located at the 10 units that it operates and corporate resources located at headquarters in Jackson, Mississippi, and at ENN offices in White Plains, New York. These resources provide significant experience, talent, and oversight that have been applied to ensure that the IP3 SPU meets all NRC requirements. The Entergy SPU Team members have more than 200 years of operations, design, licensing, and management experience at nuclear plants. Two members of the team have been licensed as Senior Reactor Operators at Indian Point.

As licensee and operator, Entergy has the overall technical, contractual, and commercial oversight and decision-making responsibility for the IP3 SPU. Entergy is responsible for oversight of the program, and has monitored the performance of its subcontractors and support organizations regarding scope of responsibility, quality of performance, compliance with schedules, and communication among team member organizations. Entergy controlled the progress of the overall project with input from each of the team member organizations. Entergy reviewed and authorized revisions to the project scope and schedule and managed the commercial implications of those changes. Entergy was responsible for contract management with regard to performance of its contractors. In select cases, Entergy provided supporting analysis based on best engineering methods and practices available for use at the time. On technical matters, Entergy consulted with its subcontractors, but had the final authority related to IP3 decisions.

Entergy reviewed results of the analyses, evaluations, and the design of planned plant modifications, and has developed a plan to incorporate them into the IP3 design and licensing basis.

1.3.2 Westinghouse Electric Company LLC

Westinghouse has extensive experience in the design and analysis of NSSS systems, including analyses and evaluations for uprates. Westinghouse has performed all of the accident and transient analyses for IP3 since the initial licensing of the plant in 1975. As the IP3 Original Equipment Manufacturer (OEM) NSSS designer and supplier, Westinghouse has extensive historical design documentation and engineering experience applicable to IP3. Westinghouse worked closely with Entergy in the recent past on the Measurement Uncertainty Recapture (MUR) Uprate Program. Because of this, many of the engineers assigned to the uprate project are familiar with the IP3 design and analyses and have worked closely with Entergy plant personnel. The Westinghouse IP3 SPU Team members have recent experience in managing power uprate projects as well as significant engineering and licensing experience applicable to IP3.

Westinghouse scope includes all NSSS-related analyses and evaluations, including the NSSS performance parameters, NSSS design transients, NSSS systems and components, design basis accidents (DBAs) (except for main steamline break [MSLB] outside containment compartment analysis), NSSS/balance-of-plant (BOP) interface, containment pressure and temperature analyses, and reactor core nuclear fuel. The NSSS scope was evaluated for 3216 MWt with 2-percent measurement uncertainty.

1.3.3 Stone & Webster

Stone & Webster (S&W) has been in the forefront of nuclear plant uprating, having successfully worked on over 23 plant uprating projects (completed or in progress) within the past 10 years. S&W has prepared implementation plans, design changes, and performed configuration management updates on the majority of these projects. Experience on these uprate projects, along with knowledge of the IP3 design, documentation system, and uprate project requirements has allowed S&W to develop a sound understanding of this project.

S&W has extensive experience in the design and analysis of BOP systems, including analyses and evaluations for uprates. Many of the S&W engineers assigned to the SPU are familiar with the IP3 design and analyses, having worked closely with Entergy plant personnel on the recent MUR Program. The S&W IP3 SPU Team members have recent experience in managing power uprate projects as well as significant engineering experience applicable to IP3.

S&W's analyses and evaluations include the BOP systems and components, including radiological and environmental evaluations. S&W also reviewed the effect on station programs.

The BOP scope of work includes engineering and associated review, evaluations, calculations, and analyses required to support the SPU at the uprated NSSS core power level of 3216 MWt and the projected initial operating power level. This work identifies effects and changes required to plant documentation and hardware, and demonstrates that the plant can operate safety, reliably, and meet regulatory requirements.

NSSS/BOP interface data were developed and exchanged among Entergy, Westinghouse, SWPC, and S&W. This information formed the foundation for the BOP reviews, evaluations, calculations, and analyses associated with the following:

- BOP systems and components
- Pipe stress and supports
- Structures
- Electrical
- BOP Instrumentation and controls
- BOP radiological review
- Environmental assessment
- Generic issues and programs
- Plant procedures

1.3.4 Siemens-Westinghouse Power Corporation and Alstom Power Generation Company

The scope of effort performed by SWPC included the engineering study to evaluate the high-pressure turbine for the SPU. The high-pressure turbine missile analysis was evaluated by SWPC.

The scope of effort performed by Alstom included the engineering study to evaluate the low-pressure turbine for SPU. Alstom (the supplier of the low-pressure turbines) reviewed the capability of the low-pressure turbine rotors for the IP3 SPU. Based on the design analysis, Alstom indicated that the rotors should be limited to an equivalent reactor power level increase of less than 4 percent. Thus, although the License Amendment Request is for 3216 MWt, the initial power increase following the approval of the license change will be limited to less than 4 percent until subsequent evaluation or modification can be made. The low pressure turbine missile analysis was evaluated by Alstom.

1.3.5 Structure of this Report

This Licensing Report is structured as follows:

Section 1, Introduction, presents background and general information related to the IP3 SPU.

Section 2, NSSS Analysis, presents the primary and secondary system design performance conditions (parameters) that were developed based on the SPU. These design performance conditions form the basis for all of the NSSS analyses and evaluations contained herein.

Section 3, NSSS and Auxiliary Equipment Design Transients, presents the results of evaluations of the design transients and how they accommodate the revised NSSS design conditions.

Sections 4, NSSS Systems, and 5, NSSS Components, present the NSSS systems (for example, safety injection, residual heat removal [RHR], and control systems) and components (for example, reactor vessel, pressurizer, reactor coolant pumps, steam generator, and NSSS auxiliary equipment) analyses, and evaluations completed for the SPU design conditions.

Section 6, Safety Analysis, provides the results of the accident analyses and evaluations performed for the various analyses areas (for example, steam generator tube rupture [SGTR], loss-of-coolant accident [LOCA] and non-LOCA accidents and transients, LOCA and MSLB mass and energy [M&E] releases, and radiological releases).

Section 7, Nuclear Fuel, addresses the effects of the uprate on the fuel and core design.

Section 8, Turbine Island Analysis, addresses the effects of the uprate on the main turbine.

Section 9, BOP Systems, addresses the effects of the uprate on the BOP systems.

Section 10, Generic Issues and Programs, addresses the effects of the uprate in the areas of plant programs and operating procedures.

Section 11, Environmental Impacts, addresses the effects of the uprate on the environmental criteria.

The analyses and evaluations described herein demonstrate that all applicable acceptance criteria will continue to be met based on operation at the SPU conditions at 3216 MWt, and that there are no significant hazards related to this power uprate according to the regulatory criteria of 10CFR50.92 (Reference 1).

1.3.6 References

1. 10CFR50.92, *Issuance of Amendment*, March 6, 1986.

1.4 Power Uprate Project Review Process

1.4.1 Input Parameters and Assumptions

Comprehensive analysis input assumption lists were developed at the beginning of the IP3 SPU for the various analytical areas within the work scope of the project. These lists were used to identify the input and assumption requirements and to obtain Entergy input data and approval. Entergy performed a review of the values used for the SPU and revalidated the analysis inputs and assumptions provided to Westinghouse, S&W, and SWPC. In conjunction with developing the individual input assumption lists, a consolidated input assumption 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 SPU. These input assumption lists have been incorporated into a database for future use by IP3 in managing and controlling analysis inputs and assumptions. Where necessary, follow-up actions have been initiated to update design basis documents to reflect the inputs and assumptions used for the SPU.

The SPU analyses were performed to reflect the as-built and as-operated plant. If plant drawings (as-built) or plant documentation were required to obtain the latest plant information for use in SPU analyses, they were obtained from Entergy and used as appropriate to obtain the needed information.

1.4.2 Methodology and Computer Codes

1.4.2.1 Nuclear Steam Supply Systems

The methodology used in evaluating the effect of the SPU on the NSSS has been structured consistent with the methodology established in Westinghouse WCAP-10263, *A Review Plan for Uprating the Licensed Power of a PWR Power Plant* (Reference 1). Since submittal of WCAP-10263 to the NRC, the methodology has been used successfully as a basis for power uprate projects on over 33 plants for a total of 1619 MWe of installed capacity. The uprate projects have ranged from a 1.0-percent to a 26.3-percent increase above base licensed power level.

The methodology in WCAP-10263 (Reference 1) established the basis and criteria for power uprate projects, including the broad categories that must be addressed, such as NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel, as well as the interfaces between NSSS and the balance-of-plant (BOP) fluid systems. Inherent in this methodology are key points that promote correctness, consistency, and licensability. The key points include the use of well-defined analysis input assumptions and parameters values, use of currently approved analytical techniques (for example, methodologies and computer codes), and use of currently applicable licensing criteria and standards.

The power uprate analyses and evaluations were performed in accordance with Westinghouse quality assurance requirements defined in the Westinghouse Quality Management System procedures, which comply with 10CFR50 Appendix B (Reference 2) criteria. These analyses and evaluations are in conformance with Westinghouse and industry codes, standards, and regulatory requirements applicable to IP3. Assumptions and acceptance criteria are provided in the appropriate sections of this report.

1.4.2.2 Computer Codes

The IP3 SPU analyses and evaluations were performed using currently approved analytical techniques to demonstrate compliance with the licensing criteria and standards that apply to IP3. In performing these analyses, methodologies and principal computer codes were used that are currently approved by the NRC. Such codes and methods have been used for IP3 and the SPU consistent with any applicable NRC guidelines or limitations.

RETRAN has previously been approved by NRC for non-loss-of-coolant accident (non-LOCA) analyses. It has been generically approved in the *Safety Evaluation Report* (SER) for WCAP-14882-P-A (Reference 3), and is applicable for use at IP3.

The GTSTRUDL computer code has not been previously used on IP3 supports analyses. GTSTRUDL is a widely used industry code for analyzing steel structures such as supports.

The other principal analytical techniques are the same as those used for current IP3 analyses as described in the IP3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 4), or in the 1.4-percent MUR LAR.

Table 1-3 contains a list of the principal computer codes used in analyses documented in this Licensing Report. Brief descriptions of the computer codes are provided in Table 1-4.

Any computer codes used in the BOP analyses are industry standards or are in compliance with S&W's quality assurance program that meets 10CFR50 Appendix B (Reference 2) and do not require specific NRC review prior to use. The computer codes used in the BOP sections are mentioned as a part of the description of the evaluation performed.

1.4.2.3 Balance of Plant

The methodology used for the BOP evaluation was the same as that used successfully in many other Power Uprate Projects. The BOP systems, structures, and components were evaluated based on the existing design and licensing basis documented in the IP3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 4) and *Technical Specification* bases. Summary results are provided in Sections 8, 9, and 10 of this report.

1.4.3 References

1. WCAP-10263, *A Review Plan for Uprating the Licensed Power of a PWR Power Plant*, 1983.

2. 10CFR50, *Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*, December 11, 1996.

3. *Safety Evaluation Report* (SER) for WCAP-14882-P-A. (Contained in WCAP-14882-P-A (Proprietary), *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, D. S. Huegel, et al., April 1999.)

4. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286.

1.5 Modifications

Reviews, analyses, and evaluations performed for the IP3 SPU have determined that no significant modifications are required to accommodate the uprate to 3216 MWt. To provide additional margin for plant operation and equipment lifetime and to optimize operating points, modifications have been identified to the following equipment for implementation of the first phase of the IP3 SPU to approximately 4 percent :

- High-pressure turbine steam path
- Moisture separator reheater (MSR)
- First-stage turbine pressure taps
- Main power transformer monitoring

To address industry issues, the following modifications are planned in conjunction with the SPU reanalysis effort.

- High-head safety injection (HHSI) flow paths
- Control room heating, ventilation, and air conditioning (HVAC) upgrades

In addition to these noted modifications, some modifications will be made to instrument ranges, and to Operating and Emergency Operating Procedures (EOPs) and setpoints.

Also, Entergy has planned to implement other modifications separate from, but concurrent with the SPU at the start of Cycle 14. These include a minor structural upgrade to the fuel assemblies planned for the reload region. The various SPU analyses and evaluations described in this report have accounted for these other modifications as necessary.

To support the completion of the SPU above the approximate initial 4 percent, the following equipment will require modification:

- Low-pressure turbine – The low-pressure (LP) turbine components were originally dimensioned for 105-percent steam flow. This applies to LP blading, inner casing, and rotors with couplings. These components can therefore be operated at a 5 percent higher steam flow rate; 9900 klb/hr at an LP inlet pressure of 203 psia. The LP turbines will operate within these design parameters at the Phase 1 power level. An increase in reactor power output to 3216 MWt necessitates modification of the LP blades to increase the swallowing capacity of the three LP turbines so that the permissible LP inlet pressure is not exceeded at the higher steam flow rate.

- Iso-Phase Bus (IPB) - The IPB main bus continuous current design ratings (forced air-cooled rating of 32 kA at 23 kV, 65°C rise) will support unit operation within the reactive power capabilities defined by the Phase 1 SPU (1080 MWe, 225 MVAR lagging to 100 MVAR leading). The IPB tap bus continuous current design rating is also capable of operation at Phase 1 SPU conditions. The IPB system requires modification or administrative limits on load management to ensure operation within the main bus and tap bus continuous current design ratings at the maximum analyzed reactor thermal power (3216 MWt) and maximum generator reactive capability (1093.5 MWe, 267 MVAR lagging).

In addition to these noted modifications, some modifications will also be made to instrument setpoints in Phase 2

1.6 Proprietary Information Designations

Westinghouse

There is information contained in this report that Westinghouse considers Westinghouse Proprietary. The specific information is contained within the brackets with designated superscripted letter (a through f), for example:

[Westinghouse Proprietary Information][a,c,e]

The reason for marking Westinghouse Proprietary information in this report is so that if any portion of this report is used to prepare documents to be submitted to the NRC (for example, a licensing report), the authors will be aware of exactly which information is proprietary to Westinghouse and can protect the information accordingly. When a licensing report or any other document is submitted to the NRC for review, either the information proprietary to Westinghouse Electric Company LLC must be omitted from the submittal, or a nonproprietary version suitable for public disclosure must also be submitted.

1.7 Conclusions

This report demonstrates that the SPU can be safely implemented at IP3. The analyses and evaluations described herein demonstrate that all applicable acceptance criteria will continue to be met based on operation at the SPU conditions at 3216-MWt core power, and that there are no significant hazards related to this power uprate according to the regulatory criteria of 10CFR50.92 (Reference 1). Specifically, this SPU can be accommodated without a significant increase in the probability or consequences of an accident previously evaluated, without creating the possibility of a new or different type of accident from any accident previously evaluated, and without exceeding any presently existing regulatory limits applicable to the plants, which may cause a significant reduction in the margin of safety.

Furthermore, Entergy has evaluated the capability of IP3 plant systems and components and has determined that, with minor modifications, the plant systems and components are capable of safely supporting the subject increase in rated core thermal power. The capability of the low-pressure turbine rotors will initially be limited to an equivalent reactor power increase of less than 4 percent. Thus, although the LAR is for 3216 MWt, the initial power increase following the approval of the license change will be limited to less than 4 percent until subsequent evaluation or modification can be made.

This IP3 SPU document is a summary of how the plant NSSS and BOP systems and components, transient and accident analyses, containment and reactor core, as well as nuclear fuel, have been addressed to support operation at the SPU power at IP3. The results of the NSSS and BOP analyses and evaluations satisfy the project purpose to demonstrate compliance with all applicable licensing criteria and requirements. Furthermore, the evaluations and analyses have identified the plant modifications required and the operational effects of the SPU. These effects have been properly documented in accordance with plant policy and procedures. This document, in combination with referenced supporting documentation, forms the basis for the IP3 SPU to 3216 MWt.

1.7.1 References

1. 10CFR50.92, *Issuance of Amendment*, March 6, 1986.

Table 1-1

Cross-Reference of Licensing Report Sections to Topical Areas

Materials and Chemical Engineering	Licensing Report Section
Reactor Vessel Material Surveillance Program	5.1 Reactor Vessel
Pressure-Temperature Limits and Upper Shelf Energy	5.1 Reactor Vessel
Pressurized Thermal Shock	5.1 Reactor Vessel
Reactor Internal and Core Support Materials	5.10 Reactor Coolant System (RCS) Potential Material Degradation Assessment
Reactor Coolant Pressure Boundary Materials	5.0 Nuclear Steam Supply System (NSSS) Components 5.10 RCS Potential Material Degradation Assessment
Leak-Before-Break (LBB)	5.4.2 Application of LBB Methodology
Protective Coating Systems (Paints) – Organic Materials	Existing requirements for protective coatings are being retained
Effect of Power Uprate on Flow Accelerated Corrosion	10.3 Flow-Accelerated Corrosion Program
Steam Generator Tube Inservice Inspection	5.6 Steam Generators
Steam Generator Blowdown System	9.5 Steam Generator Blowdown System
Chemical and Volume Control System - Including Boron Recovery	4.1.2 Chemical and Volume Control System
Reactor Water Cleanup System (Boiling Water Reactor [BWR])	NA
Pipe Rupture Locations and Associated Dynamic Effects	5.4 Reactor Coolant Loop Piping and Supports 9.9 Piping and Supports
Pressure-Retaining Components and Component Supports	4.1 Nuclear Steam Supply Fluid Systems 5.1 Reactor Vessel 5.3 Control Rod Drive Mechanisms 5.4 Reactor Coolant Loop Piping and Supports 5.7 Pressurizer 5.6 Steam Generators 5.5 Reactor Coolant Pumps and Motors 5.8 Nuclear Steam Supply System Auxiliary Equipment 9.0 Balance of Plant (BOP) Systems 9.9 Piping and Supports

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Materials and Chemical Engineering (Cont.)	Licensing Report Section	
Reactor Pressure Vessel Internals and Core Supports	5.2	Reactor Pressure Vessel System
Safety-Related Valves and Pumps	4.1	Nuclear Steam Supply Fluid Systems
	5.8	Nuclear Steam Supply System Auxiliary Equipment
	10.2	Generic Letter 89-10 Motor-Operated Valve Program
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	5.1	Reactor Vessel
	5.3	Control Rod Drive Mechanisms
	5.4	Reactor Coolant Loop Piping and Supports
	5.7	Pressurizer
	5.6	Steam Generators
	5.5	Reactor Coolant Pumps and Motors
	5.8	NSSS Auxiliary Equipment
	9.0	BOP Systems
	10.8	Electrical Equipment Environmental Qualification Program

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Electrical Engineering	Licensing Report Section	
Environmental Qualification of Electrical Equipment	10.8	Electrical Equipment Environmental Qualification Program
Offsite Power System	9.8	Electrical Systems
AC Onsite Power System	9.8	Electrical Systems
DC Onsite Power System	9.8	Electrical Systems
Station Blackout	4.1.3	Residual Heat Removal System
	4.1.6	Component Cooling Water System
	10.6	Station Blackout

Instrumentation and Controls (I&C)	Licensing Report Section	
Reactor Trip System	6.1	Initial Condition Uncertainties
	6.10	Reactor Trip System/ESF Actuation System Setpoints
ESF Systems	6.1	Initial Condition Uncertainties
	6.10	Reactor Trip System/ESF Actuation System Setpoints
Safety Shutdown Systems	6.1	Initial Condition Uncertainties
	6.10	Reactor Trip System/ESF Actuation System Setpoints
Control Systems	4.3	NSSS Control Systems
	9.10	BOP Instrumentation and Controls
Diverse I&C Systems	N/A	
General Guidance for Use of Other Standard Review Plan (SRP) Sections Related to I&C	4.3	NSSS Control Systems
	9.10	BOP Instrumentation and Controls

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Plant Systems	Licensing Report Section
Flood Protection	10.4 Flooding
Equipment and Floor Drainage System	10.4 Flooding
Circulating Water System	9.7 Circulating Water System and Main Condenser
Internally Generated Missiles (Outside Containment)	4.1.8 NSSS Evaluation of Generation of and Protection from Missiles 8.1 Steam Turbine
Internally Generated Missiles (Inside Containment)	4.1.8 NSSS Evaluation of Generation of and Protection from Missiles
Turbine Generator	8.1 Steam Turbine
Protection against Postulated Piping Failures in Fluid Systems Outside Containment	9.9 Piping and Supports
Fire Protection Program	10.1 Fire Protection (10CFR50 Appendix R) Program
Pressurizer Relief Tank	4.1.1 Reactor Coolant System
Fission Product Control Systems and Structures	N/A
Main Condenser Evacuation System	9.7 Circulating Water System and Main Condenser
Turbine Gland Sealing System	9.1 Main Steam System
Main Steam Isolation Valve Leakage Control System	N/A
Spent Fuel Pit (SFP) Area Ventilation System	9.11 Area Ventilation (Heating, Ventilation, and Conditioning [HVAC])
Auxiliary and Radwaste Area Ventilation System	9.11 Area Ventilation (HVAC)
Turbine Area Ventilation System	9.11 Area Ventilation (HVAC)
ESF Ventilation System	9.11 Area Ventilation (HVAC)
SFP Cooling and Cleanup System	4.1.7 SFP Cooling System
Station Service Water System	9.6 Essential and Non-Essential Service Water System
Reactor Auxiliary Cooling Water Systems	4.1.6 Component Cooling Water System
Ultimate Heat Sink	9.7 Circulating Water System and Main Condenser
Auxiliary Feedwater System	4.2 NSSS/BOP Interface Systems 6 Safety Analysis 9.12 Auxiliary Feedwater System

Table 1-1 (Cont.) Cross-Reference of Licensing Report Sections to Topical Areas	
Plant Systems (Cont.)	**Licensing Report Section**
Main Steam Supply System	9.1 Main Steam System
Main Condenser	9.7 Circulating Water System and Main Condenser
Turbine Bypass System	9.1 Main Steam System
Condensate and Feedwater System	9.4 Main Feedwater and Condensate System
Gaseous Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Liquid Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Solid Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Emergency Diesel Engine Fuel Oil Storage and Transfer System	9.8 Electrical Systems
Light Load Handling System (related to refueling)	6.11.5 Normal Operation Dose Rates and Shielding 6.11.9 Radiological Consequences Evaluations (Doses) 7.1 Fuel Design Features and Components

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Containments	Licensing Report Section
Dry Containments	6.5 Loss-of-Coolant Accident (LOCA) Containment Integrity 6.6.2 Steamline Break Containment Response Evaluation
Ice Condenser Containments	N/A
Pressure-Suppression Type BWR Containments	N/A
Subcompartment Analysis	6.5 LOCA Containment Integrity
Mass and Energy (M&E) Release for Postulated LOCA	6.5.1 Long-Term LOCA M&E Releases
M&E Release for Postulated Secondary System Pipe Ruptures	6.6.1 Main Steamline Break M&E Releases Inside Containment Responses 6.6.3 Main Steamline Break M&E Releases Outside Containment Responses
Combustible Gas Control in Containment	6.13 Post-LOCA Generation and Disposition of Hydrogen
Containment Heat Removal	4.1.4 Emergency Core Cooling System (ECCS) (Safety Injection System/Containment Spray System) 6.5 LOCA Containment Integrity 9.11 Area Ventilation (HVAC)
Secondary Containment Functional Design	N/A
Minimum Containment Pressure Analysis for ECCS Performance Capability Studies	6.2.1 Large-Break LOCA

Habitability, Filtration, and Ventilation	Licensing Report Section
Control Room Habitability System	6.11.9 Radiological Consequences Evaluations (Doses) 9.11 Area Ventilation (HVAC)
ESF Atmosphere Cleanup System	9.11 Area Ventilation (HVAC)
Control Room Area Ventilation System	9.11 Area Ventilation (HVAC)
SFP Area Ventilation System	9.11 Area Ventilation (HVAC)
Auxiliary and Radwaste Area Ventilation System	9.11 Area Ventilation (HVAC)
Turbine Area Ventilation System	9.11 Area Ventilation (HVAC)
ESF Ventilation System	9.11 Area Ventilation (HVAC)

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Reactor Systems	Licensing Report Section
Fuel System Design	7.1 Fuel Design Features and Components
Nuclear Design	7.3 Fuel Core Design 7.4 Fuel Rod Design and Performance
Thermal and Hydraulic Design	7.2 Core Thermal-Hydraulic Design
Functional Design of Control Rod Drive System	5.3 Control Rod Drive Mechanisms (CRDMs) 5.2.3 Rod Control Cluster Assembly (RCCA) Scram Performance Evaluation
Overpressure Protection during Power Operation	4.1 Nuclear Steam Supply System Fluid Systems 4.3.2 Pressurizer Pressure Control System Component Sizing 5.7 Pressurizer 6.3.6 Loss-of-External Electrical Load
Overpressure Protection during Low-Temperature Operation	4.3.3 Overpressure Protection System
Reactor Core Isolation Cooling System (BWR)	N/A
Residual Heat Removal System (RHRS)	4.1.3 RHRS
Emergency Core Cooling System	4.1.4 Emergency Core Cooling System (Safety Injection System/Containment Spray System)
Standby Liquid Control System (BWR)	N/A
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	6.3.9 Excessive Heat Removal Due to Feedwater System Malfunction 6.3.10 Excessive Load Increase Incident 6.3.11 Rupture of a Steam Pipe
Steam System Piping Failures Inside and Outside Containment	6.3.11 Rupture of a Steam Pipe 6.6.2 Steamline Break Containment Response Evaluation 6.6.4 Main Steamline Break outside Containment Compartment Response
Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulator Failure (closed)	6.3.6 Loss-of-External Electrical Load
Loss of Non-Emergency AC Power to Station Auxiliaries	6.3.8 Loss-of-all AC (LOAC) to the Station Auxiliaries
Loss-of-Normal Feedwater Flow	6.3.7 Loss-of-Normal Feedwater
Feedwater System Pipe Breaks Inside and Outside Containment	Not in licensing basis
Loss-of-Forced Reactor-Coolant Flow including Trip of Pump Motor and Flow Controller Malfunctions	6.3.12 Partial Loss-of-Reactor-Coolant Flow 6.3.13 Complete Loss-of-Reactor-Coolant Flow

Table 1-1 (Cont.) Cross-Reference of Licensing Report Sections to Topical Areas	
Reactor Systems (Cont.)	**Licensing Report Section**
Reactor Coolant Pump (RCP) Rotor Seizure and Reactor Coolant Pump Shaft Break	6.3.14 Locked Rotor Accident
Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Condition	6.3.2 Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition
Uncontrolled Control Rod Assembly Withdrawal at Power	6.3.3 Uncontrolled RCCA Assembly Withdrawal at Power
Control Rod Misoperation (System Malfunction or Operator Error)	6.3.4 RCCA Drop/Misoperation
Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate	Table 6.3-1 List of Non-LOCA Events
Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	6.3.5 CVCS Malfunction
Spectrum of Rod Ejection Accidents	6.3.15 Rupture of a CRDM Housing – RCCA Ejection
Spectrum of Rod Drop Accidents	6.3.4 RCCA Drop/Misoperation
Inadvertent Operation of ECCS and CVCS Malfunction that increases Reactor Coolant Inventory	NA
Inadvertent Opening of a Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve	6.2.2 Small-Break LOCA
Steam Generator Tube Rupture (SGTR)	6.4 SGTR Transient
LOCAs Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	6.2 Loss-of-Coolant Transients
Anticipated Transients Without Scram (ATWS)	6.8 ATWS
New Fuel Storage	4.1.7 SFP Cooling System 7.1 Fuel Design Features and Components
Spent Fuel Storage	4.1.7 SFP Cooling System 7.1 Fuel Design Features and Components

Table 1-1 (Cont.) Cross-Reference of Licensing Report Sections to Topical Areas	
Source Terms and Radiological Consequences Analysis	**Licensing Report Section**
Source Terms for Input into Radwaste Management Systems Analyses	6.11.4 Radiation Source Terms
Radiological Consequence Analyses Using Alternative Source Terms	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Main Steamline Failures Outside Containment for a PWR	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Reactor Coolant Pump Rotor Seizure and RCP Shaft Break	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Control Rod Ejection Accident	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Control Rod Drop Accident	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant outside Containment	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Steam Generator Tube Failure	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Main Steamline Failure Outside Containment for a BWR	N/A
Radiological Consequences of a Design Basis LOCA including Containment Leakage Contribution	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Design Basis LOCA Leakage from ESF Components outside Containment	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Design Basis LOCA Leakage from Main Steam Isolation Valves (BWR)	N/A
Radiological Consequences of Fuel-Handling Accidents	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Spent Fuel Cask Drop Accidents	6.11.9 Radiological Consequences Evaluations (Doses)

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Health Physics	Licensing Report Section
Radiation Sources	6.11.4 Radiation Source Terms
Radiation Protection Design Features	6.11.5 Normal Operation Dose Rates and Shielding
Operational Radiation Protection Program	6.11.5 Normal Operation Dose Rates and Shielding

Human Performance	Licensing Report Section
Reactor Operating Training	10.15.2 Effect on Operator Actions and Training
Training for Non-Licensed Plant Staff	10.15.2 Effect on Operator Actions and Training
Operating and Emergency Operating Procedures (EOPs)	6.12 EOPs and EOP Setpoints 10.15.1 Procedures
Human Factors Engineering	10.15 Plant Operations

Health Physics	Licensing Report Section
Power Ascension and Testing	10.15.4 Startup Testing

Health Physics	Licensing Report Section
Risk Evaluation	10.5 Probabilistic Safety Assessment

Table 1-2 Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
Section 3: NSSS and Auxiliary Systems Design Transients			
3.1 NSSS Design Transients	Affected	Evaluation and Analysis	No(1)
3.2 Aux. Equipment Design Transients	Affected	Evaluation	No(1)
Section 4: NSSS Systems			
4.1.1 RCS	Affected	Evaluation and Analysis	No
4.1.2 CVCS	Affected	Evaluation	No
4.1.3 RHR	Affected	Analysis	No
4.1.4 ECCS (SIS and CSS)	Affected	Analysis	No
4.1.5 PSS	Affected	Evaluation and Analysis	No
4.1.6 CCWS	Affected	Evaluation and Analysis	No
4.1.7 SFPCS	Affected	Analysis	No
4.2.1 MSS	Affected	Analysis	No
4.2.2 Steam Dump	Affected	Analysis	No
4.2.3 C&FS	Affected	Evaluation and Analysis	No
4.2.4 AFWS	Affected	Analysis	No
4.2.5 SG Blowdown	Affected	Evaluation	No
4.3.1 NSSS Stability & Operability	Affected	Analysis	No
4.3.2 Pressurizer Pressure Control	Affected	Analysis	No
4.3.3 OPS	Unaffected	Evaluation	No
4.3.4 I&C Systems	Affected	Evaluation	NA

Table 1-2 (Cont.)

Guidance Matrix for IP3 SPU LR

LAR Section and System		Affected or Unaffected*	Method of SPU Reconciliation • New Analysis of Record • Evaluated Effect on Current Analysis of Record	Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)
Section 5: NSSS Components				
5.1.1	RV Structural	Affected	Evaluation	No
5.1.2	RV Integrity	Affected	Analysis	No
5.2.2	RV/RVI System T&H	Affected	Analysis	No
5.2.3	RCCA Scram Performance	Affected	Analysis	No
5.2.4	RV/RVI Mechanical	Affected	Analysis	No
5.2.5	RVI Components	Affected	Evaluation	No
5.2.6	BMI Guide Tubes	Affected	Analysis	No
5.3	CRDMs	Unaffected	Evaluation	No
5.4	RCL Piping/Supports	Affected	Analysis	No
5.5	RCP Pumps / Motors	Unaffected	Evaluation	No
5.6.1	SG T&H	Affected	Analysis	No
5.6.2	SG Structural	Affected	Analysis	No
5.6.3	Primary-to-Secondary ΔP	Affected	Analysis	No
5.6.4	SG Repair Hardware	Affected	Analysis	No
5.6.5	Reg. Guide 1.121	Affected	Analysis	No
5.6.6	SG Tube Vibration / Wear	Affected	Analysis	No
5.6.7	SG Tube Integrity	Affected	Evaluation	No
5.7	Pressurizer	Affected	Analysis	No
5.8	NSSS Auxiliary Equip.	Unaffected	Evaluation	No
5.9	NSSS Fracture Integrity	Affected	Analysis	No
5.10	NSSS Material Degradation	Affected	Evaluation	No(2)

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	Affected or Unaffected*	Method of SPU Reconciliation • New Analysis of Record • Evaluated Effect on Current Analysis of Record	Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)
Section 6: UFSAR Chapter 14 Safety Analyses			
6.1 Initial Condition Uncertainties	Affected	Analysis	No
6.2 LOCA Analyses	Affected	Evaluations and Analysis	No
6.3.2 Rod Withdrawal at Subcritical	Affected	Analysis	No
6.3.3 Rod Withdrawal at Power	Affected	Analysis	No
6.3.4 RCCA Drop	Affected	Analysis	No
6.3.5 CVCS Malfunction	Affected	Analysis	No
6.3.6 Loss of Load	Affected	Analysis	No
6.3.7 Loss of Normal Feedwater	Affected	Analysis(3)	No
6.3.8 Loss of AC Power	Affected	Analysis(3)	No
6.3.9 Feedwater Malfunction	Affected	Analysis	No
6.3.10 Excessive Load Increase	Affected	Evaluations and Analysis	No
6.3.11 Main Steamline Break	Affected	Analysis	No
6.3.12 Partial Loss of Flow	Affected	Analysis	No
6.3.13 Complete Loss of Flow	Affected	Analysis	No
6.3.14 Locked Rotor	Affected	Analysis	No
6.3.15 Rod Ejection	Affected	Analysis	No
6.4 SG Tube Rupture	Affected	Analysis	No
6.5 LOCA Containment Integrity	Affected	Analysis	No
6.6.2 MSLB Containment Integrity	Affected	Analysis	No
6.6.4 MSLB Outside Containment Compartment Response	Affected	Analysis	No
6.7 LOCA Forces	Affected	Analysis	No
6.8 ATWS	Affected	Evaluation	No
6.9 Natural Circulation Cooldown	Affected	Analysis	No
6.10 RPS/ESFAS Setpoints	Affected	Analysis	No

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	Affected or Unaffected*	Method of SPU Reconciliation • New Analysis of Record • Evaluated Effect on Current Analysis of Record	Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)
6.11 Radiological Dose	Affected	Analysis	No
6.12 EOPs and Setpoints	Affected	Analysis	No
6.13 Hydrogen Generation	Affected	Analysis	No
Section 7: Fuel and Core Analyses			
7.1 Fuel Design Features and Components (Mechanical)	Affected	Analysis	No
7.2 Core T&H	Affected	Analysis	No
7.3 Fuel Core Design	Affected	Analysis	No(4)
7.4 Fuel Rod Design and Performance	Affected	Analysis	No
7.5 Neutron Fluence	Affected	Analysis	No
7.6 Reactor Internals Heat Generation Rate for RVI	Affected	Analysis	No
Section 8: Turbine Island Analysis			
8.1 Steam Turbine	Affected	Analysis	No(5, 6)
8.2 Heat Balances	Affected	Analysis	No(7)
Section 9: BOP Systems and Components			
9.1 Main Steam System	Affected	Evaluations and Analysis	No(6)
9.2 Extraction Steam System	Affected	Evaluations and Analysis	No(6)
9.3 Heater Drain Systems	Affected	Evaluations and Analysis	No(6)
9.4 Main Feedwater and Condensate System	Affected	Evaluations and Analysis	No(6)
9.5 Steam Generator Blowdown	Unaffected	Evaluation	No(6)
9.6 Essential and Non-Essential Service Water	Affected	Evaluations and Analysis	No(6)

Table 1-2 (Cont.)

Guidance Matrix for IP3 SPU LR

LAR Section and System		Affected or Unaffected*	Method of SPU Reconciliation • New Analysis of Record • Evaluated Effect on Current Analysis of Record	Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)
9.7	Circulating Water Systems and Main Condensate	Affected	Evaluations and Analysis	No(6)
9.8	Electrical Systems	Affected	Evaluations and Analysis	No(6)
9.9	Piping and Supports	Affected	Evaluations and Analysis	No(8)
9.10	BOP Instruments and Control	Unaffected	Evaluation	No(9)
9.11	Area Ventilation (HVAC)	Unaffected	Evaluation	No
9.12	Auxiliary Feedwater System	Affected	Evaluations and Analysis	No(10)
9.13	Structural Analysis (FHB/AFB)	Affected	Evaluations and Analysis	No(6)
Section 10: Generic Issues and Programs				
10.1	Fire Protection (App.R) Program	Unaffected	Evaluation	No(10)
10.2	GL 89-10 MOV Program	Unaffected	Evaluation	No
10.3	Flow-Accelerated Corrosion FAC Program	Affected	Evaluations and Analysis	No
10.4	Flooding	Unaffected	Evaluation	No
10.5	Probabilistic Safety Assessment	Affected	Evaluation	No
10.6	Station Blackout	Unaffected	Evaluation	No
10.7	In-Service Inspection, Testing (ISI, IST)	Affected	Evaluation	No
10.8	Electrical Equipment / EQ (inside & outside cont.)	Affected	Evaluations and Analysis	No
10.9	Chemistry Program	Unaffected	Evaluation	No
10.10	GL 95-07	Unaffected	Evaluation	No(6)
10.11	GL 96-06	Unaffected	Evaluation	No(6)
10.12	GL 89-13	Unaffected	Evaluation	No

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
10.13 Plant Simulator	Affected	Evaluations and Analysis	No
10.14 Containment Leak Rate Testing	Affected	Evaluations and Analysis	No(6)
10.15 Plant Operations	Affected	Evaluations and Analysis	No
Section 11: Environmental Impacts			
11 Environmental Impacts	Unaffected	Evaluations and Analysis	No

*According to the NRC Guidance for Margin Uncertainty Recapture power uprates in RIS 2002-03:

Unaffected – Unaffected systems, components, or safety analyses are those having current design and licensing bases analyses and calculations that bound the potential effects of the SPU.

Affected – Affected systems, components, or safety analyses are those having current design and licensing bases analyses and calculations that do not bound the potential effects of the SPU.

Notes:

1. Design Transients do not have acceptance criteria. Acceptance Criteria are applied to the NSSS components that are analyzed for the NSSS transients.
2. Materials requirements and evaluations continue to be applicable. Technique for evaluation of I-600 susceptibility was not previously applied to IP3.
3. Analysis input assumption changed to credit 10 minute operator action to provide additional AFW flow.
4. Core designs are checked for each reload cycle to ensure that design bases conditions are bounded.
5. Confirmation that the existing Turbine Missile analysis remains valid
6. The original licensing basis acceptance criteria for the BOP systems and components were not detailed. The criteria required that the systems function to produce power and provide reliable operation with minimal transients or trips. For the SPU, these systems were compared to industry standards and criteria to determine acceptability.
7. There are no acceptance criteria for the Heat Balance per se. The heat balance results are the inputs used for BOP systems and components evaluations and analyses.
8. BOP piping and supports were evaluated based on change factors.
9. Evaluation was based on revised Heat Balance parameters and applicable system analysis compared to instrument ranges.
10. The Licensing Basis Acceptance Criteria for this system are the acceptance criteria for the operational or safety analyses for which operation of this system or component is assumed.

Table 1-3

IP3 SPU
Principal Computer Codes Used

Report Section	Analysis	Computer Code[1]	Previously Used by IP3 or Accepted by NRC
4.3	Control Systems Operability – Margin-to-Trip Analysis	LOFTRAN (LOFT12)	Yes[2]
5.2	Reactor Internals	WECAN THRIVE	Yes[2] Yes
5.4	RCS Piping and Supports	WESTDYN GTSTRUDL	Yes[2] No[3]
5.6	Steam Generator Thermal-Hydraulic	GENF ATHOS	Yes[2] Yes[2]
6.2	Large-Break Best-Estimate LOCA (LBBELOCA)	WCOBRA/TRAC	Yes[2]
	Small-Break LOCA (SBLOCA)	NOTRUMP/ SBLOCTA	Yes[2] Yes[2]
6.3	Non-LOCA Transients	ANC FACTRAN PHOENIX-P RETRAN TWINKLE VIPRE LOFTRAN	Yes[2] Yes[2] Yes[2] Yes[4] Yes[2] Yes[2] Yes[2]
6.4	SGTR	LOFTTR2	Yes[2]
6.5	LOCA M&E LOCA Integrity Inside Containment	SATAN VI WREFLOOD EPITOME FROTH COCO	Yes[2] Yes[2] Yes[2] Yes[2] Yes[2]
6.6	MSLB inside Containment MSLB outside Containment	COCO GOTHIC	Yes[2] Yes[2]
6.6	MSLB M&E	LOFTRAN	Yes[2]
6.7	LOCA Hydraulic Forces	MULTIFLEX 3.0 LATFORC FORCE 2 THRUST	Yes[2] Yes[2] Yes[2] Yes[2]

Table 1-3 (Cont.)

IP3 SPU

Principal Computer Codes Used

Report Section	Analysis	Computer Code[1]	Previously Used by IP3 or Accepted by NRC
6.11	Radiation Source Terms	ORIGEN2.1	Yes[5]
7.1	Fuel Assemblies	NKMODE WEGAP WECAN	Yes[2] Yes[2] Yes[2]
7.2	Core Thermal-Hydraulic Design	THINC IV VIPRE	Yes[2] Yes[2]
7.3	Core Design	ANC PHOENIX-P	Yes[2] Yes[2]
7.4	Fuel Rod Design and Performance	PAD 3.4; PAD 4.0	Yes[2]
7.5	Neutron Fluence	DORT/BUGLE-96	Yes[2]
7.6	Reactor Internals Heat Generation Rates	DORT/BUGLE-96	Yes[2]

Notes:

1. See Table 1-4 for a brief description of each code.
2. Used in IP3 UFSAR or 1.4% Measurement Uncertainty Recapture (MUR) License Amendment Request.
3. GTSTRUDL is a widely used industry computer code for structural analysis.
4. RETRAN code and methods were generically approved by NRC *Safety Evaluation Report* (SER) on WCAP-14882-P-A and are applicable for use at IP3.
5. ORIGEN2.1 is a widely used transport and radiation source term code that is noted as acceptable in Regulatory Guide (RG) 1.183.

Table 1-4
Computer Code Description

ANC

ANC is an advanced nodal code capable of two-dimensional and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates one-dimensional (1-D) and two-dimensional (2-D) results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information.

ATHOS

ATHOS is a three-dimensional computer program for computational fluid dynamics (CFD) analysis of steam generators. The ATHOS code was developed under the sponsorship of the Electric Power Research Institute (EPRI).

The ATHOS code consists of geometry pre-processor, ATHOS solution, and post-processor modules. The geometry pre-processor simulates the detailed geometry. This geometry simulation includes the detailed tube layout, tube lane blocks, flow distribution baffle, tube support plates, anti-vibration bars (AVB), and opening of the primary separators. The geometry model links thermally with the primary side coolant flow. This thermal link allows the ATHOS module to calculate heat transfer from the primary coolant flow to the secondary side fluid. Therefore, the ATHOS code will calculate both heat flux and tube wall temperature, in addition to typical parameters such as liquid velocity, vapor velocity, steam quality for a two-phase flow like that in the secondary side of a steam generator.

The ATHOS code for the CFD analysis of steam generators has been verified and qualified by EPRI and Westinghouse. The post-processors can process the large amounts of output from the ATHOS calculation. Their capabilities include: (1) velocity vector plots, and (2) contour plots of thermal hydraulic parameters, such as steam quality, velocity, heat flux, and critical steam quality corresponding to departure from nucleate boiling (DNB).

Table 1-4 (Cont.)
Computer Code Description

COCO

Calculation of containment pressure and temperature is accomplished by use of the digital computer code COCO. COCO is a mathematical model of a generalized containment. The proper selection of various options in the code allows the creation of a specific model for a particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and found acceptable to calculate containment pressure transients for many dry containment plants. Transient phenomena within the RCS affect containment conditions by means of convective mass and energy transport through the pipe break.

For analytical rigor and convenience, the containment air-steam-water mixture is separated into a water (pool) phase and a steam-air phase. Sufficient relationships to describe the transient are provided by the equations of conservation of M&E as applied to each system, together with appropriate boundary conditions. Since thermo-dynamic equations of state and conditions may vary during the transient, the equations have been derived for all possible cases of superheated or saturated steam and subcooled or saturated water. Switching between states is handled automatically by the code.

DORT/BUGLE-96

The DORT discrete ordinates transport module of the DOORS 3.1 code package, in conjunction with the BUGLE-96 cross-section library, is used to determine the neutron flux and gamma-ray heating rate environment. This code and the associated cross-section library have been used by Westinghouse to calculate vessel fluences and reactor internals heating rates for other projects that have been submitted to, and approved by, the NRC. Furthermore, these calculational tools are specified in Regulatory Guide (RG) 1.190 for this type of work.

EPITOME (see also SATAN-VI and WREFLOOD)

The EPITOME code continues the post-reflood portion of the transient from the time at which the secondary side equilibrates to containment design pressure until the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables, and M&E balance tables with data at critical times. EPITOME is essentially an automated hand calculation.

Table 1-4 (Cont.)
Computer Code Description

FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metal-clad UO_2 fuel rod and the transient heat flux at the surface of the cladding, using as input the nuclear power and the time-dependent coolant parameters of pressure, flow, temperature, and density. The code uses a fuel model that simultaneously contains the following features:

- A sufficiently large number of radial space increments to handle fast transients, such as a rod ejection accident.
- Material properties that are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation.
- The necessary calculations to handle post-departure from nucleate boiling (DNB) transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel.

FORCE2 (See also MULTIFLEX, LATFORC, and THRUST)

The FORCE2 program calculates the hydraulic forces that the fluid exerts on the vessel internals in the vertical direction by using a detailed geometric description of the vessel components along with the transient pressures, mass velocities, and densities computed by the MULTIFLEX code. The analytical basis for the derivation of the mathematical equations employed in the FORCE2 code is the conservation of linear momentum (1-D). Note that the computed vertical forces in the LOCA forces analyses do not include body forces on the vessel internals, such as deadweight or buoyancy. The deadweight and other factors are part of the dynamic system model to which the LOCA forces are provided as an external load. When the vertical forces on the reactor pressure vessel (RPV) internals are calculated, pressure differential forces, flow stagnation on, and unrecoverable orifice losses across, and friction losses on, the individual components are considered. These force types are then summed together, depending upon the significance of each, to yield the total vertical force acting on a given component.

Table 1-4 (Cont.)
Computer Code Description

FROTH

The FROTH code is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the steam generator tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure, but the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two phase. During the FROTH calculation ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure, after this point the EPITOME code completes the steam generator depressurization.

GENF

GENF is a computer code developed for the steady-state, thermal-hydraulic analysis of non-preheat type vertical U-tube steam generators. Given the geometric parameters, feedwater temperature, primary side flow rate and pressure, GENF computes the circulation ratio, primary and secondary side pressure drops, secondary coolant mass inventory, stability damping factor, and depending on the mode of calculation chosen, steam pressure, primary temperatures, heat load or size of the tube bundle.

GOTHIC

GOTHIC solves the integral form of the conservation equations for mass, momentum, and energy for multi-component, two-phase flow. The conservation equations are solved for three fields; continuous liquid, liquid drops, and the steam/gas phase. The three fields may be in thermal non-equilibrium within the same computational cell. This would allow the modeling of subcooled drops (for example, containment spray) falling through an atmosphere of saturated steam. The gas component of the steam/gas field can comprise up to eight different non-condensable gases with mass balances performed for each component. Relative velocities are calculated for each field, as well as the effects of two-phase slip on pressure drop. Heat transfer among the phases, surfaces, and the fluid are also allowed. The GOTHIC code is capable of performing calculations in three modes. The code can be used in the lumped parameter nodal network mode, the 2-D finite difference mode, and the 3-D finite difference mode. Each of these modes may be used within the same model.

Table 1-4 (Cont.)
Computer Code Description

GOTHIC has been used to study hydrogen distributions, containment and compartment pressure and temperature transients, perform flow-field calculations for particle transport purposes, and surge-line flooding studies for loss of RHR cooling events during shutdown operations. The flexible noding and conservation equation solutions in the code allow its application to a wide variety of problems.

GTSTRUDL

GTSTRUDL is a finite element analysis tool suitable for general structural engineering design and analysis of framed structures, including beam, plate, and shell elements. GTSTRUDL can perform both linear and nonlinear static analyses, and linear dynamic analysis including response spectrum analysis and time history analysis. Code checking, including both AISC and ASME Section III Division 1 Subsection NF, is available.

LATFORC (See also MULTIFLEX, FORCE2, and THRUST)

The LATFORC computer code utilizes MULTIFLEX-generated field pressures, together with geometric vessel information (component radial and axial lengths), to determine the horizontal forces on the vessel wall and core barrel. The LATFORC code represents the vessel region with a model that is consistent with the model used in the MULTIFLEX blowdown calculation. The downcomer annulus is subdivided into cylindrical segments, formed by dividing this region into circumferential and axial zones. The results of the MULTIFLEX/LATFORC analysis of the horizontal forces are typically stored on magnetic tape and are calculated for the initial 500 msec of the blowdown transient. These forcing functions serve as required input in determining the resultant mechanical loads on primary equipment and loop supports, vessel internals, and fuel grids.

Table 1-4 (Cont.)
Computer Code Description

LOFTRAN

The LOFTRAN computer program is used for studies of transient response of a PWR system to specified perturbations in process parameters. LOFTRAN simulates up to four-loop systems by modeling the reactor vessel, hot- and cold-leg piping, steam generators (tube and shell sides), and pressurizer. The pressurizer heaters' spray, relief, and safety valves are also considered in the program. Point model neutron kinetics and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary sides of the steam generators use a homogeneous, saturated mixture for the thermal transients, and a water level correlation for indication and control. The Reactor Protection System (RPS) simulation includes reactor trips on neutron flux, over-power and over-temperature, reactor coolant ΔT, high and low pressure, low flow, and high pressurizer level. Control systems, including rod control, steam dump, feedwater control, and pressurizer pressure controls are also simulated. The Safety Injection System (SIS), including the accumulators, is also modeled. LOFTRAN is a versatile program suited to accident evaluation and control studies as well as parameter sizing. It is also used in performing loss of normal feedwater anticipated transient without scram (ATWS) and loss-of-load ATWS evaluations.

LOFT12 is a single-loop version of LOFTRAN used for symmetric transients. LOFT12 was also used in the previous control systems analysis for IP3.

LOFTTR2 is a version of LOFTRAN used for steam generator tube rupture analyses.

Both single-loop and multi-loop codes have been approved by the NRC.

MULTIFLEX

The analysis for LOCA hydraulic forces used the NRC-approved MULTIFLEX computer code, which is the current Westinghouse analytical tool for analyzing LOCA hydraulic forces. The code was used to generate the transient hydraulic forcing functions on the vessel and internals. This code was previously used for LOCA hydraulic forces analyses.

MULTIFLEX 3.0 is an engineering design tool that is used to analyze the coupled fluid-structural interactions in a PWR system during the transient following a postulated pipe rupture in the main RCS. The thermal-hydraulic portion of the MULTIFLEX code is based on the one-dimensional homogeneous model expressed in a set of mass, momentum, and energy conservation equations. These equations are quasi-linear, first-order, partial differential equations solved by the method of characteristics.

Table 1-4 (Cont.)
Computer Code Description

The employed numerical method utilizes an explicit time scheme along the respective characteristics. MULTIFLEX considers the interaction of the fluid and structure simultaneously, whereby the mechanical equations of vibration are solved through the use of the modal analysis technique. MULTIFLEX 3.0 generates the input for the post-processing codes LATFORC, FORCE2, and THRUST.

NKMODE

NKMODE is used to establish an equivalent finite element model that will preserve the dynamic properties of the fuel assembly. Parametric studies of the assembly vibrational frequencies and mode shapes are performed using NKMODE. NKMODE calculates a set of equivalent spring-mass elements representing an individual fuel assembly structural system.

NOTRUMP/SBLOCTA

The approved codes for Appendix K small-break LOCA (SBLOCA) analyses are NOTRUMP and SBLOCTA. The NOTRUMP computer code is a state-of-the-art, 1-D general network code consisting of a number of advanced features. Among these features are the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. Additional features of the code include a condensation heat transfer model applied in the steam generator region, a loop seal model, a core reflux model, flow regime mapping, etc.

The SBLOCTA computer code is used to model the fuel rod response to the SBLOCA transient. It models three rods in the hot assembly (hot, average, and adjacent), including simultaneous radial and axial conduction. Other modeling features include various skewed axial power shapes, assembly blockage model due to clad swell, and rupture and zirc/water reaction.

NOTRUMP is used to model the thermal-hydraulic behavior of the system and thereby obtain time- dependent values of various core region parameters, such as system pressure, temperature, fluid levels and flow rates, etc. These are provided as boundary conditions to SBLOCTA. SBLOCTA then uses these conditions and various hot channel inputs to calculate the rod heatup, and ultimately, the peak clad temperature (PCT) for a given transient. Additional variables calculated by SBLOCTA are cladding pressure, strain, and oxidation.

Table 1-4 (Cont.)
Computer Code Description

ORIGEN2.1

Fission product inventories were modeled with ORIGEN2, Version 2.1. ORIGEN2 is a versatile point-depletion and radioactive-decay computer code for use in simulating nuclear fuel cycles and calculating the nuclide compositions and characteristics of materials contained therein. The ORIGEN2 code is an industry-standard code based on the latest industry experimental data. In general, the data are up to date, well documented, and accepted by the industry. Furthermore, this calculational tool is specified in RG 1.183 for this type of work.

PAD 3.4/4.0

The NRC-approved PAD code, with NRC-approved models for in-reactor behavior, is used to calculate the fuel rod performance over its irradiation history. PAD is the principal design tool for evaluating fuel rod performance. PAD iteratively calculates the interrelated effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power. Fuel rod design and safety analyses are based on updated values (up to 100-percent helium gas release) for the integral fuel burnable absorber (IFBA) helium gas release model.

PAD is a best-estimate fuel rod performance model, and in most cases the design criterion evaluations are based on a best-estimate-plus-uncertainties approach. A statistical convolution of individual uncertainties due to design model uncertainties and fabrication dimensional tolerances is used. As-built dimensional uncertainties are measured for some critical inputs, for example, fuel pellet diameter, and when available, can be used in lieu of the fabrication uncertainties.

PHOENIX-P

PHOENIX-P is a 2-D, multi-group transport theory computer code. The nuclear cross-section library used by PHOENIX-P contains cross-section data based on a 70-energy-group structure derived from ENDF/B-VI files. PHOENIX-P performs a 2-D, 70-group nodal flux calculation that couples the individual subcell regions (pellet, cladding, and moderator) as well as surrounding rods via a collision probability technique. This 70-group solution is normalized by a coarse energy group flux solution derived from a discrete ordinates calculation. PHOENIX-P is capable of modeling all cell types needed for PWR core design applications.

Table 1-4 (Cont.)
Computer Code Description

RETRAN

RETRAN is used for studies of transient response of a PWR system to specified perturbations in process parameters. This code simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot- and cold-leg piping, RCPs, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves may also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The RPS simulated in the code includes reactor trips on high neutron flux, overtemperature ΔT (OTΔT) and overpressure ΔT (OPΔT), low RCS flow, high- and low-pressurizer pressure, high-pressurizer level, and lo-lo steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the SIS, including the accumulators, may be modeled. RETRAN calculates the transient value of departure from nucleate boiling rate (DNBR) based on input from the core thermal safety limits.

SATAN-VI (See also WREFLOOD and EPITOME)

The SATAN code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform, and thermo-dynamic equilibrium is assumed in each element. A point-kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis.

Table 1-4 (Cont.)
Computer Code Description

THINC IV

The THINC-IV computer program is used to determine coolant density, mass velocity, enthalpy, vapor void, static pressure, and DNBR distributions along parallel flow channels within a reactor core under expected steady-state operating conditions. This code has had extensive experimental verification and is considered a best-estimate code. The THINC-IV analysis is based on a knowledge and understanding of the heat transfer and hydro-dynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The THINC-IV analysis provides a realistic evaluation of the core performance.

THRIVE

The Thermal Hydraulic Reactor Internals Vessel Evaluation (or THRIVE) code models the reactor vessel and internals system in Westinghouse PWRs and performs the following computations:

- Reactor vessel pressure losses for the thermal design, best estimate, mechanical design, hot-pump overspeed, and cold-full flow rates
- Reactor vessel-internals associated core bypass flows
- Reactor internals baffle-barrel region flow rates
- Baffle joint momentum flux and baffle jetting margins of safety
- Baffle plate pressure relief hole velocities
- Reactor internals hydraulic uplift forces
- Hydraulic and geometrical data for use in nuclear safety, fluid systems and reactor internals component analyses

The THRIVE code predicts the RV pressure losses by classical analytical fluid mechanics. THRIVE solves the following continuity and momentum equations for a flow system that represents the entire reactor vessel and internals system:

$$W = \rho VA = \text{constant}$$

$$P_j = P_i + \sum_i^j (K + fl/D)\frac{\rho V^2}{2g_c}$$

Table 1-4 (Cont.)
Computer Code Description

- Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes
- Ability to represent important reactor components such as fuel rods, steam generators, RCPs, etc.

WECAN

The WECAN computer code is a general-purpose, finite element code with capabilities including structural and thermal-hydraulic static and dynamic analyses. It is a direct descendent of the mainframe-version of the WECAN code that has been used in the nuclear industry since the early 1970s. It has been used by Westinghouse for safety-related work for many years on essentially all Westinghouse-provided NSSS analyses, such as core structural design (analyses including static, dynamic, and thermal), primary piping, primary equipment supports, primary equipment components, and spent fuel rack design.

The WECAN computer program can be used to solve a large variety of structural analysis problems. These problems can be 1-, 2-, or 3-D in nature. It is capable of static elastic and inelastic analysis, steady-state hydraulic analysis, standard and reduced modal analysis, harmonic response analysis, and transient dynamic analysis.

The WECAN program is based on the finite element method of analysis. The analyst must model, or idealize, the structure in terms of discrete elements and apply loadings and boundary conditions to these elements. The stiffness (or conductivity) matrix for each element is assembled into a system of simultaneous linear equations for the entire structure. This set of equations is then solved by a variation of the Gaussian elimination method known as the wave-front technique. This type of solution makes it possible to solve systems with a large number of degrees of freedom using a minimum amount of core storage. The maximum number of allowed degrees of freedom in the wave front depends on the amount of core available, which in turn depends on the type of analysis being performed.

WECAN is organized in such a way that additional structural elements can be added with a minimum of effort. Input formats are similar for all elements and all types of analysis. Input used in the static analysis of a structure can be used for a dynamic analysis with only minor modifications.

Table 1-4 (Cont.)
Computer Code Description

WEGAP

WEGAP calculates the dynamic structural response of a PWR core. WEGAP represents the transient structural response of one row of fuel assemblies, including impact at the grid elevation. With the appropriate analysis parameters such as grid impact stiffness and damping, the number of fuel assemblies in a planar array and gap clearance established, the WEGAP reactor core model is used for analyzing transient loadings.

WESTDYN

WESTDYN, a computer program used for the structural analysis of piping systems, calculates displacement, internal forces, and stress distributions in 3-D piping models, while subjecting them to static and dynamic loads.

The static analysis includes pressure, deadweight, thermal expansion, distributed and point loads, anchor motion, and uniformly applied accelerations.

The dynamic analysis includes seismic or hydro-dynamic response spectra and time-history dynamic analysis. The time-history dynamic analysis includes options for non-linear supports, support gaps, and unidirectional single acting restraints.

In addition, WESTDYN uses post-processors for the stress analysis of American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3, or ANSI B31.1 piping, and also for generating support load summary sheets and equipment, and component qualification input data.

WESTDYN automatically calculates stress indices for standard ANSI fittings by user selection of the ASME piping evaluation code and edition. Allowable piping stress limits, coefficients of thermal expansion, and moduli of elasticity for a wide range of materials are also automatically calculated with user-supplied design and operating data.

Table 1-4 (Cont.)
Computer Code Description

WREFLOOD (See also SATAN-IV and EPITOME)

The WREFLOOD code is used for computing the reflood transient. It addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break, and when water supplied by the Emergency Core Cooling System (ECCS) refills the reactor vessel and cools the core.

The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel, and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped safety injection and accumulators, RCP performance, and steam generator releases are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters, such as core flooding rate, core downcomer water levels, fluid thermo-dynamic conditions (that is, pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system.

2.0 NUCLEAR STEAM SUPPLY SYSTEM ANALYSIS

The stretch power uprate (SPU) included Nuclear Steam Supply System (NSSS) performance analyses to develop bounding NSSS Performance Capability Working Group (PCWG) parameters for use in the analyses and evaluations of the NSSS, including parameters for NSSS design transients and analyses of systems, components, accidents, and nuclear fuel.

2.1 Nuclear Steam Supply System Parameters

2.1.1 NSSS Performance Capability Working Group Parameters

The Nuclear Steam Supply System (NSSS) primary and secondary system design parameters are the fundamental system condition inputs (temperatures, pressures, and flow) that are used as the basis for all of the NSSS analyses and evaluations. They provide the Reactor Coolant System (RCS) and secondary system conditions (temperatures, pressures, flow) that are used as the basis for the design transients and for systems, components, accidents, and fuel analyses and evaluations. Revised design parameters were developed to reflect the increase in the Indian Point Unit 3 (IP3) licensed core power from 3067.4 to 3216 MWt. The parameters for the 3067.4-MWt measurement uncertainty recapture (MUR) are shown in Table 2.1-1 (Reference 1). The stretch power uprate (SPU) parameters are shown in Table 2.1-2. As discussed in this report, the parameters in Table 2.1-2 have been reconciled with the applicable systems and components evaluations, as well as safety analyses, performed in support of the SPU.

The PCWG parameters were established using conservative assumptions to provide bounding conditions to be used in the NSSS analyses. For example, the RCS flow assumed in generating the primary and secondary side conditions was the thermal design flow (TDF), which was a conservatively low flow that accounted for flow measurement uncertainty and assumed a steam generator tube plugging (SGTP) level of 10 percent. The resulting primary and secondary side design conditions will bound actual plant operations at the 3216-MWt SPU level.

The method and mathematical model used to calculate the IP3 design parameter values in Table 2.1-2 used basic thermal, hydraulic, and engineering principles, including mass and energy (M&E) balances. The code used to determine the NSSS design parameters is called SGPER (Steam Generator PERformance). Explicit NRC approval is not needed for SGPER, since it is used to facilitate fundamental engineering calculations that could be performed by hand. The code, method, and mathematical model have been successfully used to support all previous uprates for Westinghouse plants.

2.1.2 Input Parameters and Assumptions

Four cases of design performance parameters were developed for the IP3 SPU to cover combinations of SGTP and T_{avg} operating conditions. The following assumptions were common to all four sets:

- Westinghouse Model 44F steam generators

- TDF of 88,600 gpm/loop

- NSSS uprated power level of 3216 MWt core power with a high value of 14 MWt net heat input from the primary RCS reactor coolant pumps (RCPs)

- Westinghouse 15 x 15 Vantage+ and upgrade fuel design (see Section 7.0)

- Total design core bypass flow of 5.5 and 7.5 percent that accounts for intermediate flow mixing (IFM) grids

- T_{feed} range of 433.6° to 390°F

2.1.3 Discussion of Parameter Cases

Table 2.1-2 provides the NSSS design parameter cases generated and used as the basis for the SPU. Four cases were developed.

The four cases are distinguished as follows:

Case 1 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 0-percent SGTP.

Case 2 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 10-percent SGTP.

Case 3 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 0-percent SGTP.

Case 4 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 10-percent SGTP.

2.1.4 Acceptance Criterion

There are no specific acceptance criteria for this section. The PCWG parameters provide bounding conditions to be used in the NSSS analyses with appropriate levels of conservativism that would also provide Entergy with adequate margin for plant operation and to meet design and licensing bases acceptance criteria. Where the analyses determined a more limiting condition, that is noted in the discussion for each analysis.

2.1.5 Results and Conclusions

The resulting PCWG parameters are shown in Table 2.1-2.

2.1.6 References

1. Entergy Nuclear Operations, Incorporated, *Indian Point Nuclear Generating Unit No. 3, 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, May 2002. (Approved in License Amendment 213 on November 26, 2002.)

Table 2.1-1 Design Power Capability Parameters IP3 3067.4 MWt (Current Plant Design)			
Thermal Design Parameters	**Set 1**	**Set 2**	**Set 3**
NSSS Power %	100	100	100
MWt	3082	3082	3082
10^6 Btu/hr	10,516	10,516	10,516
Reactor Power MWt(1)	3068(1)	3068(1)	3068(1)
10^6 Btu/hr	10,468	10,468	10,468
Thermal Design Flow, loop gpm	89,700	80,900	80,900
Reactor 10^6 lb/hr	136.3	123.4	122.9
Reactor Coolant Pressure, psia	2250	2250	2250
Core Bypass, %	5.2	5.2	5.2
Reactor Coolant Temperature, °F			
Core Outlet	603.7	607.0	610.0
Vessel Outlet	600.8	603.8	606.9
Core Average	574.2	574.6	577.9
Vessel Average	571.5	571.5	574.7
Vessel/Core Inlet	542.2	539.2	542.5
Steam Generator Outlet	541.9	538.9	542.2
Steam Generator			
Steam Temperature, °F	512.7	498.9	502.4
Steam Pressure, psia	762	674	696
Steam Flow, 10^6 lb/hr total	13.26	13.23	13.24
Feed Temperature, °F	427.4	427.4	427.4
Moisture, % max.	0.10	0.10	0.10
Tube Plugging Level (%)	0	24	24
Zero Load Temperature, °F	547	547	547
Hydraulic Design Parameters			
Mechanical Design Flow, gpm/loop		99,100	
Tech Spec Minimum Measured Flow, gpm total		375,600	
Minimum Measured Flow used in analyses (lowest in core design analysis), gpm total		330,800	

Notes:

1. Conservatively bounds the MUR uprate value of 3067.4.

Table 2.1-2 Design Power Capability Parameters IP3 3216 MWt[4]				
Thermal Design Parameters	**Case 1**	**Case 2**	**Case 3**	**Case 4**
NSSS Power %	100	100	100	100
MWt	3230[5]	3230[5]	3230[5]	3230[5]
10^6 Btu/hr	11,021	11,021	11,021	11,021
Reactor Power MWt	3216	3216	3216	3216
10^6 Btu/hr	10,973	10,973	10,973	10,973
Thermal Design Flow, loop gpm	88,600[9]	88,600[9]	88,600[9]	88,600[9]
Reactor 10^6 lb/hr	138.8	138.8	134.8	134.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	5.5/7.5[2,10]	5.5/7.5[2,10]	5.5/7.5[2,10]	5.5/7.5[2,10]
Reactor Coolant Temperature, °F				
Core Outlet	584.2/585.5[10]	584.2/585.5[10]	606.2/607.5[10]	606.2/607.5[10]
Vessel Outlet	580.7	580.7	603.0	603.0
Core Average	551.8/552.6[10]	551.8/552.6[10]	575.1/575.8[10]	575.1/575.8[10]
Vessel Average	549.0	549.0	572.0	572.0
Vessel/Core Inlet[12]	517.3	517.3	541.0	541.0
Steam Generator Outlet[12]	517.0	517.0	540.7	540.7
Steam Generator				
Steam Temperature, °F	484.6	480.2	509.7[6]	505.4
Steam Pressure, psia	591[3,13]	567[3,13]	743[3,6]	715[3]
Steam Flow, 10^6 lb/hr total	13.15/13.94[8]	13.14/13.93[8]	13.20/13.99[6,8]	13.18/13.98[8]
Feed Temperature, °F	390/433.6	390/433.6	390/433.6	390/433.6
Moisture, % max.	0.10	0.10	0.10	0.10
Tube Plugging Level (%)	0	10	0	10
Zero Load Temperature, °F	547	547	547	547

Table 2.1-2 (Cont.) **Design Power Capability Parameters** **IP3 3216 MWt**	
Hydraulic Design Parameters	
Pump Design Point, Flow (gpm)/Head (ft.)	89,700/272
Mechanical Design Flow, gpm per loop	101,300[11]
Tech Spec Thermal Design Flow, gpm total (TDF Proposed as new Tech Spec consistent with MMF relocated to COLR according to TSTF-339)	354,400
Minimum Measured Flow[7] used in all analyses, gpm total (MMF being relocated from Tech Specs to COLR consistent with TSTF-339)	364,700[1,7]

Notes:
1. Fuel features include: I-Spring ZIRLO mid grids, improved IFMs, and protective bottom grid (see Section 7.0).
2. Core bypass flow has been increased to the range of 5.5 to 7.5% to cover the fuel features.
3. 17 psi steam generator internal pressure drop is incorporated.
4. For the current plant design basis, see Table 2.1-1.
5. RCP heat addition of 14 MWt is included.
6. If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 787 psia, steam temperature of 516.3°F, and steam flow of 14.01×10^6 lb/hr should be assumed. This envelopes the possibility that the steam generator could perform better than expected.
7. Minimum measured flow (MMF) is based on 2.9% flow measurement uncertainty.
8. Steam flow is affected by the two different feedwater temperatures.
9. TDF supports 10% SGTP based on current plant flow measurements.
10. Core outlet and core average temperatures are affected by the two different core bypass values
11. MDF is increased to provide margin.
12. Actual operation of IP3 is limited to a minimum T_{cold} of 525°F to support the vessel integrity calculations (see subsection 5.1.2).
13. Steam pressure is limited to 650 psia to avoid violation of the steam generator primary-to-secondary pressure differential limit of 1700 psid.

3.0 NUCLEAR STEAM SUPPLY SYSTEM AND AUXILIARY EQUIPMENT DESIGN TRANSIENTS

This section discusses the generation of the Nuclear Steam Supply System (NSSS) and auxiliary equipment design transients for the stretch power uprate (SPU) power conditions. Current NSSS design transients were analyzed for their continued applicability at SPU power, and the resulting transient curves were provided to all system and component designers for use in their specific analyses. Section 3.1 describes the evaluation performed. Auxiliary equipment design transients were also evaluated to determine whether they remain applicable for use in the SPU analysis of all the auxiliary equipment in the NSSS. The results of this evaluation are presented in Section 3.2 of this report.

3.1 Nuclear Steam Supply System Design Transients

3.1.1 Introduction

As part of the original design and analyses of the Nuclear Steam Supply System (NSSS) components for Indian Point Unit 3 (IP3), NSSS design transients (that is, temperature and pressure transients) were specified for use in the analyses of the cyclic behavior of the NSSS components. These were later revised to encompass the replacement steam generator (RSG) in the 1986 to 1988 timeframe. A limited number of them were revised for the 1.4-percent measurement uncertainty recapture (MUR) Uprate Program in 2001. To provide the necessary high degree of integrity for the NSSS components, the transient parameters selected for component stress analyses were based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various plant operating conditions. The transients selected for use in component stress analyses were representative of operating conditions that could occur during plant operations and were considered to be sufficiently severe or frequent to be of possible significance to component stress analysis. The transients were selected to be conservative representations of transients that, when used as a basis for component stress analysis, would provide confidence that the component was appropriate for its application over the operating license period of the plant. For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

3.1.2 Input Parameters and Assumptions

NSSS design transients are based primarily on the NSSS design parameters as discussed in Section 2 of this report. The NSSS design parameters, upon which the existing NSSS design transients were based, were compared to the NSSS parameters for the SPU and shown to be noticeably different. The differences were primarily due to:

- The SPU is implementing a T_{avg} window (549° to 572°F)
- The SPU is implementing a feedwater temperature window (390° to 433.6°F)

The NSSS design transients were revised to reflect the changes to the NSSS parameters.

3.1.3 Description of Analyses and Evaluations

The NSSS parameters for the original plant power level and for the SPU power level were compared and it was noted that the incorporation of the T_{avg} operating window and the feedwater temperature window required changes in the existing design transients. In addition, the IP3 Model 44F steam generator design includes a primary-to-secondary pressure differential design limit of 1550 psid. If this was to be maintained, it would require that the minimum steam pressure for full power be set significantly above the NSSS parameter values. To minimize the plant operations impact and to result in the maximum operating flexibility, this primary-to-secondary pressure differential design limit was increased to 1700 psid (See Section 5.7). This is the same value that has been incorporated in the similar Indian Point Unit 2 (IP2) Model 44F steam generators.

The NSSS parameters for 3230-MWt NSSS power level conditions were used in the design transient development. The resulting plant operating conditions used in the design transient development are shown in Table 3.1-1.

The design transients were redeveloped for the IP3 SPU operating conditions and have been used in the NSSS component and fatigue analyses and evaluations presented in Section 5 of this report.

The NSSS design transients are developed for stress analyses of the various NSSS components. Conservatism is generally included in them via the analysis assumptions associated with either the frequency of occurrence or the transient assumptions. These include:

- Frequencies of occurrence are developed in a conservative fashion. For example, while the plants are operated in a base-loaded fashion, it is assumed that every day a plant loading from 0- to 100-percent power followed by an unloading from 100- to 0-percent power occurs. For the upset transients, it is assumed a reactor trip from 100-percent power occurs 400 times over the plant life (that is, 10 times each year for every year of operation). A loss-of-load is assumed to occur 80 times over the plant life (that is, 2 times each year for 40 years of operation). These transient occurrences are conservative in comparison to actual plant operating experience.

- Conservatisms are taken in the transient analysis assumptions. For example, the normal condition design transients are analyzed assuming they are all at beginning-of-core life (BOL) conditions with conservatively low nuclear reactivity feedback parameters, resulting in the minimum reactivity feedback and maximum parameter (for example, Reactor Coolant System [RCS] and pressurizer pressure and temperature) transient variations. The loss-of-load transient is analyzed like a conservative anticipated transient without scram (ATWS) event, with no reactivity feedbacks, no credit for any control systems, and no reactor trip until the pressurizer is nearly water-solid. The reactor trip transient is assumed to occur at BOL core conditions to result in the minimum decay heat and the maximum RCS cooldown.

The SPU also includes a feedwater temperature window between 390° and 433.6°F for full-power operating conditions.

3.1.4 Acceptance Criteria

There are no specific acceptance criteria for the design transients. See Section 5 for component criteria.

3.1.5 Results and Conclusions

The design transient parameter history curves and tabular data were provided to the various component analysts for their use in assessing the component stresses and cumulative fatigue usage factors. See Section 5 of this report for component results and conclusions.

Table 3.1-1 Operating Conditions for Existing Design Transients vs. SPU Values			
Parameter	Present Design	SPU	
		High T_{avg}	Low T_{avg}
T_{hot}, °F	600.8	603.0	580.7
T_{cold}, °F(1)	541.9	540.7	517.0
T_{steam} , °F	512.7	505.4(2)	494.9(3)
P_{steam}, psia	762	715(2)	650(3)
T_{feed}, °F	427.8	433.6 / 390	433.6 / 390

Notes:

1. Steam generator outlet; reactor vessel/core inlet is 0.3°F higher.
2. Values are for the maximum steam generator tube plugging (SGTP) condition; these bound the 0% SGTP conditions for design transient development.
3. Values are minimum full-power steam pressure (and corresponding temperature) to avoid violating the steam generator primary-to-secondary pressure differential limit of 1700 psid.

3.2 Auxiliary Equipment Design Transients

3.2.1 Introduction

The Indian Point Unit 3 (IP3) auxiliary equipment design specifications included transients that were used to design and analyze the Class 1 auxiliary nozzles connected to the Reactor Coolant System (RCS) and certain Nuclear Steam Supply System (NSSS) auxiliary systems piping, heat exchangers, pumps, and tanks. These transients are described by variations in pressure, fluid temperature, and flow and represent umbrella cases for operational events postulated to occur during the plant lifetime. To a large extent the transients are based on engineering judgment and experience and are considered to result in parameter changes of such magnitude, or to occur frequently enough, to be significant in the component design and fatigue evaluation processes. The transients are sufficiently conservative that, when used as a basis for component fatigue analysis, they provide confidence that the component will perform as intended over the operating license period of the plant. For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

As part of the IP3 stretch power uprate (SPU), the auxiliary equipment design transients were reviewed to assess continued applicability.

3.2.2 Input Parameters and Assumptions

The review of the auxiliary equipment design transients was based on the range of NSSS design parameters listed in Table 2.1-2 of this report. The approved range of NSSS design parameters for the SPU was compared with the current NSSS design parameters listed in Table 2.1-1 of this report.

3.2.3 Description of Analyses and Evaluation

An evaluation of the current design transients was performed to determine which transients could be affected by the SPU. The evaluation concluded that the only design transients that could be affected by the SPU are those temperature transients affected by full-load RCS design temperatures.

These temperature transients are defined by the differences between the temperature of the coolant in the RCS loops and the temperature of the coolant in the auxiliary systems connected to the RCS loops. The greater the temperature difference, the greater the effect these temperature transients have on auxiliary component design and stress evaluation. Since the operating coolant temperatures in the auxiliary systems are not affected by SPU, the temperature difference between the coolant in the auxiliary systems and the coolant in the RCS loops is only affected by changes in the RCS operating temperatures.

The current design temperature transients are based on a full-load T_{hot} of 630°F and a full-load T_{cold} of 560°F. These full-load temperatures were assumed for equipment design to ensure that the temperature transients would be conservative for a wide range of NSSS design parameters.

3.2.4 Acceptance Criteria and Results

A comparison of the range of NSSS design temperatures for an SPU at full-load, that is T_{hot} (580.7° to 603.0°F) and T_{cold} (517.3° to 541.0°F) with the T_{hot} and T_{cold} values used to develop the current design transients, indicates that the SPU temperature ranges are lower. These lower full-load operating temperatures result in less severe transients since the temperature differences are lower between RCS loop temperatures and the lower operating temperatures in the auxiliary systems connected to the RCS. For example, the temperature transients imposed on the Chemical and Volume Control System (CVCS) letdown and charging nozzles associated with starting and stopping letdown and charging flow would be less severe since the temperature differences are less. Therefore, the current body of auxiliary design transients is conservative for the proposed SPU.

3.2.5 Conclusions

The only auxiliary equipment transients that can be potentially affected by the SPU are those temperature transients related to full-load NSSS design temperatures. A review of these temperature transients indicates that if these transients were based on the SPU design parameters, they would be less severe. Therefore, the current auxiliary equipment design transients for IP3 remain bounding for the proposed IP3 SPU.

4.0 NUCLEAR STEAM SUPPLY SYSTEM

This section describes the evaluation of the Nuclear Steam Supply System (NSSS) fluid systems that support the stretch power uprate (SPU). Evaluations and analyses were performed to confirm that the NSSS fluid systems continue to perform their intended functions under the SPU conditions. The systems addressed in this section are as follows:

Fluid Systems:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Residual Heat Removal System (RHRS)
- Emergency Core Cooling System (ECCS) (Safety Injection System [SIS]/Containment Spray System [CSS])
- Primary Sampling System (PSS)
- Component Cooling Water System (CCWS)
- Spent Fuel Pit Cooling System (SFPCS)

Results and conclusions are presented within each subsection.

4.1 Nuclear Steam Supply System Fluid Systems

Introduction

This section of the report evaluates the Nuclear Steam Supply System (NSSS) fluid systems for the Indian Point Unit 3 (IP3) stretch power uprate (SPU) conditions. The plant NSSS design data to be evaluated for both the current plant conditions and the SPU power levels are presented in Tables 2.1-1 and 2.1-2, respectively. The data in Table 2.1-2 were evaluated for the SPU.

This report section addresses the following NSSS systems:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Residual Heat Removal System (RHRS)
- Emergency Core Cooling System (ECCS)
  - Safety Injection System (SIS)
  - Containment Spray System (CSS)
- Primary Sampling System (PSS)
- Component Cooling Water System (CCWS)
- Spent Fuel Pit Cooling System (SFPCS)

The fluid systems evaluations described in this section were performed at the system level. Evaluations of the NSSS components are described in Sections 5.1 through 5.10 of this report.

4.1.1 Reactor Coolant System

The changes in NSSS design parameters that affect the RCS design bases functions include the increase in core power and the allowable range for average RCS temperature (T_{avg}). Verification that the major RCS components can support these changes is addressed in Sections 5.1 through 5.10 of this report. The increase in core power and the allowable RCS T_{avg} range also affect the duty placed on the RCS control and protection systems. Verification that the RCS control and protection systems can support the SPU is addressed in Section 4.3 of this report. This section of the report discusses the RCS fluid system design. The system design considerations include the pressurizer surge line, safety valves inlet and discharge piping, pressurizer relief tank (PRT), power-operated relief valve (PORV) inlet and discharge piping, pressurizer spray subsystem, and RCS instrumentation setpoints (excluding instrument channels used by the control and protection systems).

RCS Design Parameters

The NSSS design parameters at the SPU power level are shown in Table 2.1-2. The revised parameters that affect RCS performance are core power and the resulting full-load T_{cold} and T_{hot} temperatures. The steady-state RCS pressure (2235 psig) and no-load RCS temperature (547°F) have not changed. The changes in full-load RCS temperatures are shown below:

RCS Temperatures	1.4% MUR Parameters	SPU Parameters
T_{cold} (SG Outlet)	541.9°F	517° to 540.7°F
T_{hot} (Vessel Outlet)	600.8°F	580.7° to 603.0°F

These uprate parameters are based on a T_{avg} window of 549° to 572°F. (The 1.4-percent measurement uncertainty recapture [MUR] uprating T_{avg} was 571.5°F.)

RCS Design Temperature and Pressure

The RCS is specified with a design pressure of 2485 psig and a nominal operating pressure of 2235 psig. The RCS design temperature is 650°F with the exception of the pressurizer, which is designed to 680°F. Based on the SPU RCS parameters, the RCS design pressure and temperature continue to bound the uprated operating conditions.

The RCS transient operating conditions and associated RCS overpressure evaluations resulting from the RCS and plant transients are discussed in other sections of this report, as follows:

- RCS pressure control via the pressurizer heaters and spray systems, including the capability of the surge line, spray valves, and associated instrumentation and setpoints is discussed in Section 4.3.
- RCS inventory control via the pressurizer level control systems, including the associated instrumentation and setpoints is discussed in Section 4.3.
- RCS temperature control, including the associated instrumentation, is discussed in Section 4.3.

- Protection system actuation, including the associated instrumentation and setpoints, is discussed in Section 6.10.

- RCS piping analyses, based on the SPU operating conditions, are discussed in Section 5.4.

Therefore, it is concluded that the RCS design temperature and pressure are not affected by the uprated conditions, and the design of the RCS pressure boundary is maintained within the original design limits.

RCS Heat Capacity

The RCS heat capacity is defined as the amount of heat (in Btus) required to raise or lower the RCS temperature by one degree Fahrenheit (Btu/°F), or, the amount of sensible heat that must be removed or added to the RCS for a given change in RCS temperature. The RCS heat capacity is derived from the composite of the RCS fluid(s) and the component masses. RCS component mass is not changing while the SPU change in RCS fluid mass is insignificant.

Therefore, it is concluded that the RCS heat capacity is not affected by the SPU.

Reactor Coolant Pump Net Positive Suction Head

This section addresses reactor coolant pump (RCP) net positive suction head (NPSH) and the Residual Heat Removal System (RHRS) suction valves open-permissive interlock, as it relates to RCS flow. Adequate RCP NPSH, at the RCP suction, is monitored by using the RCS wide-range pressure instrument. This same pressure transmitter also provides an input signal to the RHRS suction valves open-permissive interlock. Since the RCS wide-range pressure instrument tap is somewhat removed from the RCP suction point (the wide-range pressure instrument is located in the RCS hot leg), the pressure drop from the RCS wide-range pressure transmitter to the RCP suction must be included when using this instrument for monitoring RCP NPSH. This pressure drop is a function of RCS flow, in addition to other plant physical parameters such as RCS component and piping losses. The RCP NPSH and RHR open permissive interlock were evaluated for SPU RCS flow conditions (for the SPU fuel considered at this time) and remain acceptable for the SPU conditions.

Therefore, it is concluded the RCP NPSH and RHR open permissive interlock are acceptable for the SPU.

Pressurizer Spray Flow

The pressurizer spray flow is used for RCS pressure control. The driving head for pressurizer spray is the pressure difference from the reactor coolant loop (RCL) spray nozzle to the RCL surge nozzle and is a function of RCS flow and temperature. Since the changes in RCS temperatures are small at the SPU conditions, there is no effect on pressurizer spray performance as a result of the RCS temperature changes at SPU conditions. The RCS flow for the SPU conditions is greater than the flow assumed in the spray performance analysis.

Therefore, it is concluded that acceptable spray flow is provided at the SPU conditions.

Pressurizer Spray and Surge Line Low-Temperature Alarms

The pressurizer surge line and pressurizer spray line temperature instruments are provided to indicate that the minimum spray and surge line flows are met, so that thermal shock to these lines is minimized when these lines are in use. Since the changes in SPU no-load and minimum full-power RCS hot and cold leg temperatures are very small, the nominal 500°F setpoints of these instruments are not affected by the SPU conditions.

Therefore, it is concluded that acceptable low temperature alarms are provided at the SPU conditions.

Pressurizer Relief Tank

The PRT is designed to accept and quench the design basis discharge from the pressurizer steam space. The PRT is conservatively sized to condense and cool a discharge of steam equivalent to 110 percent of the full-power pressurizer steam volume for the loss-of-load/turbine trip analysis. The amount of energy absorbed by the PRT is related to the volume and pressure of the steam discharged. As indicated in Table 2.1-2, RCS pressure has not changed for the SPU conditions. However, pressurizer level has changed (lower) at the SPU conditions for the full T_{avg} window considered, and was evaluated for the PRT. The sizing/design basis mass released to the PRT is not exceeded since there is no complete filling of the pressurizer permitted for the SPU loss-of-load/turbine trip analysis. The current design basis for the PRT bounds the SPU loss-of-load/turbine trip analysis mass addition, such that the PRT continues to meet its design basis mass addition, without any changes in the current PRT setpoints.

Therefore, it is concluded that acceptable PRT performance is provided at the SPU conditions, without any changes in the current PRT setpoints.

RCS Net Heat Input

The RCS net heat input was determined for the SPU to be 12.6 MW. This value reflects the net heat input for the daily calorimetric at the SPU conditions and justifies the conservative 14 MW used in the various SPU analyses using net heat input for full-power operation.

Therefore it is concluded that conservative RCS net heat input parameters, based on SPU conditions, were used for the SPU analyses.

4.1.2 CVCS

The changes in NSSS design parameters that could potentially affect the CVCS design bases functions include the increase in core power and the allowable range for RCS full-load design temperatures. The increase in core power and the allowable range for RCS full-load design temperatures may also affect the CVCS design bases requirements related to the core re-load boron requirements. Additionally, the allowable range for RCS full-load design temperatures may affect the heat loads that the CVCS heat exchangers (HXs) must transfer to the CCWS, and in the case of the regenerative HX, to the charging flow.

Regenerative Heat Exchanger

The regenerative HX cools the normal letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the regenerative HX is 555°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 547°F (see Table 2.1-2). The no-load RCS temperature has not changed, while the full-load SPU T_{cold} temperature has decreased by a small amount. The performance of the regenerative HX (that is, less limiting, slightly decreased charging and letdown temperatures) is acceptable at SPU conditions with the minor change in letdown flow (due to the small change in RCS T_{cold} temperature).

Therefore it is concluded that acceptable regenerative HX performance is provided at the SPU conditions, with no plant changes required.

Non-Regenerative Heat Exchanger

The non-regenerative HX cools the letdown flow from the regenerative HX. Since the change in performance of the regenerative HX is less limiting at SPU conditions, as discussed in the previous section, there will be a small (less limiting) effect on the performance of the non-regenerative HX. The minor difference in performance (decreased cooling water flow) can easily be accommodated within the capability of the non-regenerative HX cooling water temperature control valve, AC-TCV-130.

Therefore it is concluded that acceptable non-regenerative HX performance is provided at the SPU conditions, with no plant changes required.

Excess Letdown Heat Exchanger

The excess letdown HX cools the excess letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the excess letdown HX is 555°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 547°F. Since the no-load RCS temperature has not changed, and the full-load SPU T_{cold} temperature has decreased by a small amount, the performance of the excess letdown HX is acceptable at SPU conditions with the change in RCS T_{cold} temperature.

Therefore it is concluded that acceptable excess letdown HX performance is provided at the SPU conditions, with no plant changes required.

Seal Water Heat Exchanger

The seal water HX cools the seal return flow from the four RCP No. 1 seals and the excess letdown flow (from the excess letdown HX) if it is in service. The RCP heat load (including the thermal barrier HX) is a function of RCS T_{cold} temperature, while the excess letdown heat load is a function of excess letdown HX performance. Since the no-load RCS temperature has not changed, and the full-load SPU T_{cold} temperature has decreased by a small amount, the performance of the seal water HX is acceptable at SPU conditions with the change in RCS T_{cold} temperature.

Therefore it is concluded that acceptable seal water HX performance is provided at the SPU conditions, with no plant changes required.

Charging, Letdown, and RCS Make-Up (Boration, Dilution, and N-16 Delay Time)

As discussed in the above sections for the various CVCS HXs, there are minor (lower temperatures) effects on their performance at the SPU conditions. Therefore, there will also be very small flow effects on the charging (including RCP seal injection) and letdown performance provide by the CVCS that the plant can easily adjust to. The flow capacity performance of the RCS make-up system is independent of the change in RCS conditions resulting from the SPU conditions. However, the make-up system also relies on storage capacity of various sources of water including primary make-up water and boric aid solutions from both the boric acid storage tanks and the refueling water storage tank (RWST).

Primary make-up water is used to dilute RCS boron, to provide positive reactivity control or to blend concentrated boric acid to match the prevailing RCS boron concentration during RCS inventory make-up operations. Since the flow capacity performance of the RCS make-up system is independent of the change in RCS conditions resulting from the SPU conditions as discussed above, the SPU does not affect the capability of the make-up system to perform these system functions.

The boric acid storage tanks and RWST provide the sources of boric acid for providing negative reactivity control to supplement the reactor control rods. The SPU is expected to have a small effect on the boration requirements that must be provided by the CVCS boration capabilities. The maximum expected RCS boron concentrations are within the capability of the CVCS. The Westinghouse reload safety evaluation (RSE) process (Reference 1) is designed to address boration capability for routine plant changes, such as core reloads, and infrequent plant changes such as a plant uprating that result in a change to core operating conditions and initial core reactivity. Therefore, boration capability will be addressed during the RSE process for each reload cycle.

The letdown flow path is routed inside containment such that there is adequate decay of N-16 before the letdown fluid leaves the containment building. Since the change in letdown flow is very small, as discussed in the previous paragraphs, this radiation protection feature of the CVCS is not affected by the SPU. However it is noted that the letdown line and excess letdown line radiation dose rates from N-16 (for example, amount of N-16) will slightly increase proportional to the increase in reactor power level.

Therefore, it is concluded the CVCS charging, letdown and RCS makeup performance is acceptable at the SPU conditions, considering the following points:

- The boration capability will be addressed during the Reference 1 RSE process for each reload cycle

- There will be a small increase in letdown line dose rates from N-16, proportional to the slight increase in reactor power level

4.1.2.1 Primary Chemistry Control

The changes in plant parameters that affect the primary chemistry program for IP3 were evaluated for SPU conditions. As noted in the NSSS parameters (Table 2.1-2 of this document), the range of vessel average temperature (T_{avg}) extends from 549° to 572°F; the range of T_{hot} extends from 580.7° to 603.0°F for the SPU. The best-estimate T_{avg} is expected to be 567°F. The RWST maximum boron concentration is listed in the IP3 *Improved Technical Specifications* (ITS) (Reference 2) as 2600 ppm. No change in RCS pH control is being recommended for the SPU. The design parameters (Table 2.1-1 of this document) for the 1.4-percent MUR Program provided an RCS T_{avg} of 571.5°F and T_{hot} of 600.8°F with no SGTP.

The chemistry of the NSSS is usually considered to be the chemical composition of the primary coolant and the secondary coolant, and the chemistry programs are designed to keep concentrations of various chemicals within industry-accepted guidelines. These guidelines were prepared by a committee of industry experts and reflect field and laboratory data on primary coolant system corrosion and performance issues. Chemicals present include those purposely added for corrosion and pH control, contaminants, and boric acid added as a chemical shim on the primary side.

The IP3 SPU results in relatively small temperature changes in primary and secondary coolant temperatures, and these new operating conditions are well within the envelope of conditions used in developing the industry chemistry guidelines.

Therefore, it is concluded the IP3 plant chemistry limits based on industry guidelines remain acceptable at the IP3 SPU conditions, and no changes to the primary chemistry program are required for the IP3 SPU.

4.1.3 Residual Heat Removal System

The higher SPU power level results in an increase in the amount of residual heat being generated in the core during normal cooldown, refueling operations and accident conditions. This provides a higher heat load on the residual HXs during the cooldown and also during the refueling outage. The removal of core decay heat for accident conditions is also addressed in other parts of Section 4 below and in Section 6 of this report. The increased heat loads will be transferred to the Component Cooling Water System (CCWS) and ultimately to the Service Water System (SWS). Evaluation of the SPU performance of the RHRS in conjunction with the CCWS and SWS with the increased heat loads is addressed in this subsection and in subsections 4.1.6 and 9.6 of this report.

The SPU affects the plant cooldown time(s) since core power, and therefore the decay heat increases. The plant cooldown calculation was performed at a core power of 3216 MWt to support the SPU. The RCS heat capacity and the other RHR heat loads were explicitly considered in these analyses. The analysis was performed to confirm that the RHR and CCW systems continue to meet their design basis functional requirements and performance criteria for plant cooldown under the uprated power conditions. The two-train system alignment was considered to address the design capability in the *Indian Point Unit 3 Updated Final Safety Analysis Report* (UFSAR) (Reference 3). In addition, a cooldown analysis was performed to support the worst-case scenario for the 10CFR50 Appendix R (Reference 4) fire hazards and safe shutdown analysis.

The following considerations were applied to these cooldown analyses:

- The CCW and RHR HX data assumes 5-percent tube plugging, as was used for the previous cooldown analyses of record (AOR). This results in slightly degraded normal cold shutdown and Appendix R cooldown performance.
- The design service water temperature of 95°F was assumed. For normal cooldown, the CCWS supply temperature is limited to 120°F, while for Appendix R cooldown, the CCWS supply temperature is limited to 125°F.
- Various CCWS auxiliary heat loads and the RCS heat capacity were included in the normal cooldown cases and the Appendix R plant cooldown case. These heat loads, along with an increase in the spent fuel pool heat load (assuming a full SFP of fuel that has operated at 3216 MWt) were used in the cooldown analysis.
- Decay heat curves based on 24-month fuel cycles were used.
- Service water (SW) flow rates for Appendix R cooldown were varied to minimize SW flow demand while meeting the Appendix R criteria as shown in Table 4.1-1.

As shown by the results summary in Table 4.1-1, the normal plant cooldown time to 140°F with both trains of CCW and RHR available increased from 94.1 hours for the 1.4-percent MUR to 105 hours for the SPU. The normal plant cooldown time to 200°F with both trains of CCW and RHR available increased from 17 hours for the 1.4-percent MUR to 21 hours for the SPU. The primary reason for this is the uprated core power and the corresponding increase in the SFP auxiliary heat load on the CCWS. Since there is no design criterion for normal plant cooldown time, these increases in calculated values, based on design conditions, are acceptable.

The Appendix R/safe shutdown cases continue to meet the 72-hour time limit for cold shutdown. For these cases, the minimum CCW HX service water flow to meet the time 72 hour cooldown time limit criterion was determined as shown in Table 4.1-1.

It is concluded that acceptable RHR cooldown performance is provided at the SPU conditions for normal plant cooldown and the limiting Appendix R/safe shutdown cases, based on the service water flows shown in Table 4.1-1.

4.1.4 Emergency Core Cooling System (SIS/CSS)

The required volume, duration, and heat rejection capability of the Safety Injection System (SIS) and Containment Spray System (CSS) flows in the event of a postulated accident were determined based on analytical and empirical models that simulate reactor and containment conditions subsequent to the postulated RCS and Main Steam System (MSS) breaks. As a result of these analyses, the system and component criteria necessary to demonstrate compliance with regulatory requirements at the SPU power level were established. Since the results of these analyses (see Section 6 of this report) have demonstrated that SIS and CSS provide adequate safety margin, the SIS and CSS are acceptable for the SPU conditions.

The scope of this discussion regarding the ECCS includes the SIS (both low-head and high-head systems) and the CSS performance. Subsequent to ECCS and CSS actuation, the SIS draws water from the RWST during the injection phase and delivers it to the RCS, while the CSS simultaneously draws from the RWST and sprays the containment atmosphere. At the conclusion of RWST draindown, operation of the CSS is terminated. Also at the conclusion of RWST draindown, the SIS is switched to the containment recirculation alignment, drawing fluid from the containment sump. The SIS can also provide recirculation spray to the CSS, if required for continued containment cooling, during the recirculation phase.

Minimum and maximum containment spray flows from the RWST were calculated for the SPU. These spray flows were used in the SPU containment accident analyses. The high-head safety injection (HHSI) and low-head safety injection (LHSI) system flow performance was also calculated in support of the SPU accident analyses, including operation during the longer term recirculation phase. The SPU accident analyses are discussed further in Section 6 of this report.

As a result of the SPU requiring higher HHSI hot leg flows, the HHSI system was modified by permanently closing two cold leg branch lines, and throttling the high head safety injection system to provide higher cold leg and hot leg flows. Also, system changes were made to enhance spilling line performance for the LOCA analysis. The HHSI system performance analysis also considered the recirculation sump particle criteria and the system throttle valve cavitation issues.

As a result of the SPU requiring higher LHSI cold leg recirculation flows, the LHSI system operation was modified for the recirculation phase of operation. Re-throttling of the LHSI system butterfly valves (via revised EOP setpoints) provides the higher LHSI cold leg flows (while also providing the required recirculation spray flow).

There could be a small effect (a slight increase in sump fluid temperature) during recirculation since decay heat slightly increases (with power level). The post-loss-of-coolant accident (post-LOCA) containment sump temperature performance along with changes (increases) in recirculation flow have been addressed for the RHR HX tube side, and it is concluded that acceptable RHR HX temperature and flow performance is obtained.

It is concluded that the flow performance of CSS, HHSI and LHSI systems determined for the SPU are acceptable. The post-LOCA recirculation flow and temperature performance of the RHR HX is also acceptable based on the SPU sump temperature results.

4.1.5 Primary Sampling System

The change in NSSS design parameters that potentially affect the Primary Sampling System (PSS) design bases is the allowable range for average RCS design temperature (T_{avg}). The PSS provides fluid samples from the RCS (pressurizer and hot leg) for laboratory analysis. The sample flows from the RCS are cooled (pressurizer steam samples condensed and cooled) via HXs. Since the SPU alters RCS loop operating temperatures, the PSS HXs were evaluated to assess the effect on the design duty of these HXs.

The scope of this evaluation is limited to the high-pressure, remotely obtained samples from the RCS since these sample locations set the limiting process conditions that govern the design of the PSS and associated sample coolers. The PSS is discussed in Section 9.4 of the UFSAR (Reference 3). The limiting duty for the RCS sample coolers is based on the capability of the cooler to condense and cool a sample stream from the pressurizer steam space. The maximum normal steam condition within the pressurizer is based on the saturation steam temperature (653°F) at normal operating RCS pressure, since the pressurizer is maintained at saturation conditions for RCS pressure control. As discussed in the RCS section above, the RCS operating pressure has not changed at the SPU conditions. Therefore, the design duty of the PSS is not affected as a result of the SPU.

It is concluded the PSS design bounds the SPU operating conditions and therefore is not affected as a result of the SPU.

4.1.6 Component Cooling Water System

The CCWS is an intermediate system between the various radioactive fluid systems and the Service Water System (SWS). It ensures that radioactivity leakage from the components being cooled is contained within the plant. Revised heat rejection rates and cooling water flow requirements were assessed for the SPU.

Normal Plant Operations (at-Power and Refueling)

The design bases of the CCWS for IP3 are described in the Section 9.3 of the UFSAR (Reference 3). The plant heat loads on the CCWS are as follows:

- RHR HXs
- Charging pumps (bearing and fluid-drive oil coolers)
- Seal water HX (RCP no. 1 seal-leak off return and excess letdown)
- Non-regenerative HX
- Primary sample HX (pressurizer steam, pressurizer liquid, RCS)
- Steam generator blowdown sample HX
- Radiation monitor condenser sample cooler
- Excess letdown HX (during plant heatup)
- Reactor vessel support cooling blocks
- RCP motor-bearing oil coolers (upper and lower)
- RCP thermal barrier HX
- SFP HX
- Waste gas compressors (seal water cooling and seal water make-up)
- Residual heat removal (RHR) pumps
- SI pumps
- Recirculation pump motors

As noted in Section 2, the NSSS at-power parameters (T_{hot} and T_{cold}) both hot and cold leg temperatures go down at full power and the no-load T_{avg} remains unchanged. The initial containment temperature limit (130°F) remains unchanged. Of the CCWS heat loads discussed above, the SFP is the only heat load with a potential to affect the CCWS during normal plant operation. The interaction of the SFPCS and the CCWS is addressed in subsection 4.1.7 for normal plant operation and refueling. All other heat loads are not affected by the SPU during normal (at-power) plant operation.

Therefore, it is concluded the CCWS is not affected by the SPU during normal power operation, except for the effects of the SFPCS, addressed in subsection 4.1.7 for normal plant operation.

Normal and 10CFR50 Appendix R (Fire Protection) Plant Cooldown

The CCWS provides cooling to the RHR HXs during plant cooldown. (See subsection 4.1.3 for discussion of plant cooldown performance.) During plant cooldown, the RHR HX heat load is controlled by throttling RCS flow so that an acceptable CCWS supply temperature is maintained to the CCWS-serviced equipment. Based on the results of the updated RHR cooldown work described in subsection 4.1.3, the historical CCWS supply temperature limits have been maintained for the SPU. For normal cooldown, the CCWS supply temperature is limited to 120°F, while for Appendix R cooldown, the CCWS supply temperature is limited to 125°F.

Therefore, it is concluded that CCWS operation during plant cooldown is acceptable for the SPU because the RHR cooldown analyses show acceptable cooldown time results with the above CCW supply temperature limits.

Post-LOCA Plant Cooldown

The CCWS supports post-LOCA ECCS operation during recirculation by providing cooling to the RHR HXs. There could be a small effect (a small increase in sump fluid temperature) during recirculation since decay heat slightly increases with reactor power level. The post-loss-of-coolant accident (post-LOCA) containment sump temperature performance along with changes (increases) in recirculation flow have been addressed for CCW cooling to the RHR HXs, and it is concluded that acceptable RHR HX CCW temperature performance is obtained.

It is concluded that the post-LOCA and CCW temperature performance of the RHR HX is acceptable based on the SPU recirculation flow and sump temperature results.

4.1.7 Spent Fuel Pit Cooling System

Spent Fuel Pit Cooling System Performance during Normal Plant Operation

The SPU affects the SFPCS performance since core power, and therefore the decay heat of the fuel assemblies increases. The SFPCS performance calculation supports the SPU core power of 3216 MWt. The analysis was performed to confirm that the SFPCS and CCWS continue to meet their design basis functional requirements and performance criteria for plant cooldown at the SPU power conditions.

The following assumptions were applied to the SFPCS performance analysis:

- The SFPCS and CCW heat exchanger data assumes 5-percent tube plugging.

- All SFP fuel was assumed to have operated at the SPU reactor power of 3216 MWt to provide a conservative bounding basis for the SFP decay heat load.

- Decay heat curves were based on 24-month fuel cycles.

- The analysis evaluated the capability of the SFPCS and the CCWS to cool the SFP based on SW temperatures of 70° and 95°F.

The SFP maximum normal heat load is 17.6 MBTU/hr. This is based on 20 days elapsed time since the previous shutdown with the maximum number of fuel assemblies in the SFP while still having core offload capacity. With the SFP at 150°F, the SFP heat exchanger with 5-percent tube plugging, and 70°F SW, the SFP heat exchanger will remove 27.2 MBTU/hr. With the SFP at 150°F, the SFP heat exchanger with 5 percent tube plugging, and 95°F SW, the SFP heat exchanger will remove 17.6 MBTU/hr.

Therefore, it is concluded that under these conditions, the SFPCS has sufficient heat removal capacity. These heat load results are also used as input for the CCW system auxiliary heat load analyses as appropriate.

Refueling Operation SFPCS Performance

The SFP contains spent fuel discharged from the reactor over its operating life. The SPU affects the SFPCS performance since core power, and therefore, the decay heat of the fuel assemblies increases. Due to the conservatism in the heat load calculations, the assumption of 5-percent plugging of the SFP HX tubes and the remote probability that the maximum allowable SW and CCW temperatures would occur simultaneously and coincident with a refueling offload, a cycle-specific heat load evaluation using the anticipated actual conditions at the time of the offload will be performed prior to each refueling outage. This evaluation, based on expected SW temperature, CCW flow, SFP HX performance capability, supplemental heat removal capability, and reload-specific SFP heat removal requirements will determine the decay time and supplemental cooling capability required so that bulk SFP temperature will remain below 200°F (full-core offload).

If the calculation shows that the SFP temperature will exceed 200°F with supplemental cooling, movement of fuel from the reactor into the SPF will not occur until the fuel has decayed to an acceptable level. The required hold time will be documented in the evaluation. Maintaining the SFP bulk temperature at 200°F or less is consistent with the current operation and design of the SFPCS, as well as the SFP structure itself. Therefore, by administratively controlling the in-core hold time of the fuel after shutdown to ensure that the SFP temperature does not exceed 200°F, it will not be necessary to make physical or analytical modifications to the SFP or its cooling system as a result of the SPU.

Two criteria must be met before spent fuel can be discharged to the SFP:

- Spent fuel can not be discharged to the SFP until at least 84 hours after shutdown to satisfy the assumptions of the spent-fuel handling accident analysis, as discussed in subsection 6.11.9 of this report.

- An additional delay time limit prior to spent fuel discharge is administratively controlled by operating procedures to ensure that the total spent fuel heat load is within the capacity of the spent fuel cooling loop as augmented by supplemental cooling capability to satisfy the bulk pit water temperature limits discussed above. This is a variable time limit primarily dependant upon SW temperature, and cooling capacity with supplemental cooling.

SFP Criticality

The requirements of 10CFR50.68(b) apply to IP3 and remain valid for the upgrade fuel design. As discussed in Section 7 (Reference 5) of this document, the main changes in the upgrade fuel assembly are grid changes and the grids are not modeled in the 10CFR50.68(b) analyses. Furthermore, the current criticality analyses use Zircaloy/Zirc-4, while the upgrade fuel assembly will use ZIRLO. Since ZIRLO has a slightly higher absorption of neutrons, the current analysis remains bounding.

4.1.7.1 Analysis Methods for Reload-Specific SFPCS Capability Calculations

Calculation of Decay Heat Load in SFP

The calculation of the decay heat load on the SFP will be based on the contents of the SFP at the time of the reload. A census of the actual fuel assemblies in the SFP prior to the offload will be used in conjunction with the decay heat characteristics of the fuel to be placed in the SFP from the core. The heat load will be based on decay time, power history, and inventory of the SFP.

Calculation of Heat Removal Capacity

The calculation of heat removal capacity will be based on parameters that affect cooling capability. The specific inputs to the calculation will be chosen to be representative of the conditions predicted to exist at the time the core offload is scheduled to take place.

Representative values will be chosen for SW temperature, decay heat load in the SFP, SW, and CCW cooling system flow rates, and HX performance parameters (heat transfer area and tube plugging).

The calculation of supplemental heat removal capacity will be based on the excess cooling needed to keep the SFP temperature below 200°F at the time of planned core offload. Representative values will be chosen for SW temperature, decay heat load in the SFP, SW, and CCW cooling system flow rates, and HX performance parameters (heat transfer area and tube plugging). If the combination of SFPCS capability and supplemental cooling capability is not sufficient, then the planned core offload time will be delayed until the combined capacity is sufficient.

A 10-percent uncertainty factor is applied to all calculated heat loads in accordance with the recommendation of Branch Technical Position ASB 9-2 (Reference 6).

Administrative Controls for SFP Cooling Implementation

Administrative controls for SFP cooling implementation will be included in IP3 procedures.

Adequate Make-Up Supply

The make-up needs have been assessed for normal SFP conditions with a maximum number of fuel assemblies that have been operated. The SFP maximum normal heat load is 17.6 MBtu/hr. This is based on 20-days elapsed time since the previous shutdown with the maximum number of fuel assemblies in the SFP while still having core offload capacity. If the SFP were to lose all cooling under these conditions with an initial pool temperature of 150°F, the time to boil would be 4.9 hours. The required make-up for boiloff with this heat load would 60 gpm. Make-up water can be supplied within this time and at this rate from the primary water storage tank (PWST), the RWST, or the Fire Protection System.

The refueling core offload heat load was evaluated for SPU conditions to determine the make-up needs. The evaluation assumed a maximum number of fuel assemblies that have been operated at 3216 MWt. With no heat removal by installed or supplemental cooling capability, the time for the SFP water to rise from 200° to 212°F is at least 33 minutes. The maximum required make-up rate for boiloff is 100 gpm (for a full core offload). Make-up water can be supplied within this time and at this rate from the PWST, the RWST, or the Fire Protection System.

4.1.7.2 Conclusions Regarding Reload-Specific SFPCS Capability Calculations

Because the offload-specific calculations will determine the SFP capability required and such capability will be provided before fuel is offloaded to the SFP, acceptable SFPCS performance will be provided for the SPU conditions. In the event of a total failure of the SFPCS, the SFP heat inertia will allow sufficient time to place make-up water capability into service. The required SFP make-up capability for the most limiting case requires 100-gpm make-up. The make-up water can be supplied within the required time and at this rate from the PWST, the RWST, or the Fire Protection System.

4.1.8 NSSS Evaluation of Generation of and Protection from Missiles

All NSSS rotating equipment remains within its design criteria and therefore, there is no change in the missile analysis or in the protection provisions as a result of the SPU. Any physical plant changes required for the IP3 SPU have not adversely affected the missile protection capability of IP3.

Based on the insignificant changes in system pressure and temperature conditions during plant operation and anticipated operational occurrences as a result of the IP3 SPU, NSSS systems, structures and components important to safety will continue to meet requirements for generation of and protection from internally generated missiles following implementation of the SPU.

It is concluded that the generation of and protection from internally generated missiles is not affected following implementation of the SPU.

4.1.9 References

1. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, F. M. Bordelon et al., July 1985.

2. Indian Point Unit 3 Improved Technical Specifications, Amendment No. 203, License No. DPR-64, Docket No. 50-286.

3. Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report, Rev. 18, Docket No. 50-286.

4. 10CFR50, Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979.

5. NRC Branch Technical Position ASB 9-2, Residual Decay Energy for Light-Water Reactors for Long-Term Cooling (contained in U.S. NRC Standard Review Plan 9.2.5, "Ultimate Heat Sink," Rev. 2, July, 1981.

6. 10CFR50.68, *Criticality Accident Requirements*, November 12, 1998.

Table 4.1-1 SPU Cooldown Analyses Results				
Cases	Cooldown Time to 140°F (hrs. after shutdown)	Cooldown Time to 200°F (hrs. after shutdown)	RHR Initiation Time @350°F (hrs. after shutdown)(1)	Total SW Flow (gpm)
1. Normal Cooldown with CCW Aux Heat Loads	105.0	21	5.0	9100
2. Normal Cooldown without CCW Aux Heat Loads	84.8	14.0	4.0	9100
3. App. R, Enhanced CCW UA/U, 5700 gpm SW Flow	N/A	64.8(2)	29.0	5700
4. App. R, Enhanced CCW UA/U, SW Flow Minimized to Meet 72-hr. Cooldown Time	N/A	71.8	29.0	4700
5. App. R, Original Design SSC UA/U, SW Flow Minimized to Meet 72-hr. Cooldown Time	N/A	71.9	29.0	5324
6. Same as 3 without SFP Heat Load	N/A	58.0(2)	29.0	5700
7. Same as 4 without SFP Heat Load	N/A	71.8	29.0	3596
8. Same as 5. Without SFP Heat Load	N/A	72.0	29.0	3918

Notes:

1. The 29-hour cut-in time for the Appendix R cases, limited by the CCWS supply temperature, is also indicative of the cut-in time assumed in the radiological consequences analyses of accidents with secondary side releases (that is, SGTR).
2. These cases increase the component cooling water return piping temperature compared to the previous 1.4% MUR Appendix R analysis. Previous Appendix R cases had a maximum return temperature of 173°F, and the temperature for Case 6 is 188°F, which remains bounded by post-LOCA conditions.

4.2 NSSS/Balance-of-Plant Interface Systems

The Westinghouse sizing criteria for the Nuclear Steam Supply System/balance-of-plant (NSSS/BOP) interface (Section 6.2 of Reference 1) were originally established to provide guidelines to the BOP designer to ensure that the BOP design would be compatible with the NSSS. Following completion of the BOP designs for each plant, the BOP design parameters and capabilities were then used in the accident and transient analyses to demonstrate that the entire plant design had sufficient capability to accommodate accidents and transients that were postulated. The sizing criteria were checked for each uprate to determine if there is a potential for unacceptable results for accident or transient analyses that constitute the acceptance and licensing criteria for the plant components systems.

As part of the Indian Point Unit 3 (IP3) stretch power uprate (SPU), the following BOP fluid systems were reviewed against the Westinghouse NSSS/BOP interface guidelines:

- Main Steam System (MSS)
- Steam Dump System
- Condensate and Feedwater System (C&FS)
- Auxiliary Feedwater System (AFWS)
- Steam Generator Blowdown System (SGBS)

The review was based on the range of NSSS design parameters approved for an NSSS power level of 3230 MWt (see Section 2 of this report). The current design parameters are those approved for the 1.4-percent measurement uncertainty recapture (MUR) with an NSSS power of 3082 MWt (Section 6.2 of Reference 1). The interface systems were reviewed to determine changes to interface information for use in the more detailed BOP analyses discussed in Section 9 of this report.

A comparison of the SPU design parameters (Table 2.1-2) with the current design parameters (Table 2.1-1) previously evaluated for systems and components indicates differences that could affect the performance of the BOP systems.

Evaluations of the above BOP systems relative to the Westinghouse NSSS/BOP interface guidelines were performed to address the NSSS design parameters for the SPU that include ranges for parameters such as T_{avg} (549° to 572°F), steam generator tube plugging (SGTP) (0 to 10 percent), and feedwater temperature (390° to 433.6°F). These ranges on NSSS design parameters result in ranges on BOP parameters such as steam generator outlet pressure (567 to 787 psia) and steam/feedwater mass flow rates (13.14 x 10^6 lb/hr to 14.01 x 10^6 lb/hr) (Table 2.1-2). The NSSS/BOP interface evaluations were performed to address the effect of these NSSS design parameters on the BOP. The results of the NSSS/BOP interface evaluations are discussed in the following sections.

4.2.1 Main Steam System

The following subsections summarize the evaluation of the NSSS interface on the MSS major components relative to the SPU parameters. The major components of the MSS are the steam generator main steam safety valves (MSSVs), the steam generator power-operated atmospheric relief valves (ARVs), and the main steam isolation valves (MSIVs) and non-return valves.

4.2.1.1 Steam Generator MSSVs

The setpoints of the MSSVs are based on the design pressure of the steam generators (1085 psig) and the requirements of the *ASME Boiler and Pressure Vessel (B&PV) Code* (Reference 2). Since the design pressure of the steam generator has not changed for SPU, there is no need to revise the setpoints of the safety valves.

The MSSVs must have sufficient capacity so that main steam pressure does not exceed 110 percent of the steam generator shell-side design pressure (the maximum pressure allowed by the ASME B&PV Code) for the worst-case loss-of-heat-sink event (Reference 3). Based on this requirement, Westinghouse applies the conservative criterion that the valves should be sized to relieve 100 percent of the maximum calculated steam flow at an accumulation pressure not exceeding 110 percent of the MSS design pressure.

IP3 has 20 safety valves with a total rated capacity of 15.108 x 10^6 lb/hr, which provides about 107.8 percent of the maximum SPU full-load steam flow of the 14.01 x 10^6 lb/hr (see Table 2.1-2). Therefore, based on the range of NSSS design parameters for the SPU, the capacity of the installed MSSVs meets the Westinghouse sizing criterion.

The original design requirements for the MSSVs (as well as the ARVs and steam dump valves) included a maximum flow limit per valve of 890,000 lb/hr at 1085 psig. Since the actual capacity of any single MSSV, ARV, or steam dump valve is less than the maximum flow limit per valve, the maximum capacity criteria are satisfied.

The MSSVs are also discussed in Section 9.1 and the capability of the MSSVs is analyzed for the limiting design basis transient (loss-of-load event) in subsection 6.3.6 of this report. The analysis in subsection 6.3.6 demonstrates that the MSSVs are capable of maintaining the secondary side steam pressure below 110 percent of the steam generator shell design pressure.

4.2.1.2 Steam Generator Power-Operated ARVs

The ARVs, which are located upstream of the MSIVs and adjacent to the MSSVs, are automatically controlled by steam line pressure during plant operations. The ARVs automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint to minimize safety valve lifting during steam pressure transients. As the steam line pressure decreases, the ARVs modulate closed and reseat at a pressure below the opening pressure. The ARV set pressure for these operations is between zero-load steam pressure and the setpoint of the lowest set MSSVs. Since neither of these pressures changes for the proposed range of NSSS design parameters, there is no need to change the ARV setpoint.

The primary function of the ARVs is to provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the ARVs, in conjunction with the AFWS, permit the plant to be cooled down from the pressure setpoint of the lowest-set MSSVs to the point at which the Residual Heat Removal System (RHRS) can be placed in service. During cooldown, the ARVs are either automatically or manually controlled. In automatic, each ARV proportional and integral (P&I) controller compares steamline pressure to the pressure setpoint, which is manually set by the plant operator.

To limit the frequency of main steam safety valve (MSSV) lifts, the setpoints of the ARVs are based on plant no-load conditions (2250 psig and 547°F) and the lowest MSSV setpoint. Since neither of these pressures changes for the proposed range of NSSS design parameters, there is no need to change the ARV setpoint.

In the event of a tube rupture event in conjunction with loss-of-offsite power (LOOP), the ARVs are used to cool down the RCS to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set MSSV. RCS cooldown and depressurization are required to preclude steam generator overfill and to terminate activity release to the atmosphere (Reference 3 and Section 6.4).

The steam generator ARVs are sized to have a capacity equal to about 10 percent of rated steam flow at no-load pressure. This capacity permits a plant cooldown to RHRS operating conditions (350°F) in 4 hours (at a rate of about 50°F/hr), assuming cooldown starts 2 hours after reactor shutdown. This sizing is compatible with normal cooldown capability and minimizes the water supply required by the AFWS. This design basis is limiting with respect to sizing the ARVs, and bounds the capacity required for tube rupture.

An evaluation of the installed capacity (2,467,000 lb/hr at 1020 psia) indicates that the original design bases in terms of plant cooldown capability can still be achieved for the range of SPU NSSS design parameters.

4.2.1.3 MSIVs, MSIV Bypass Valves, and Non-Return Valves

The MSIVs and non-return valves are located outside the containment and downstream of the MSSVs and ARVs. The valves function to prevent the uncontrolled blowdown of more than one steam generator and to minimize the RCS cooldown and containment pressure to within acceptable limits following a main steamline break (MSLB). To accomplish this function, the design requirements specified that the MSIVs must be capable of closure within 5 seconds of receiving a closure signal against steam break flow conditions in the forward direction.

Rapid closure of the MSIVs and non-return valves following postulated steamline breaks causes a significant differential pressure across the valve seats and a thrust load on the MSS piping and piping supports in the area of the MSIVs and non-return valves. The worst cases for differential pressure increase and thrust loads are controlled by the steamline break area (affecting mass flow rate and moisture content), throat area of the steam generator flow restrictors, valve seat bore, and no-load operating pressure. Since the SPU does not affect these variables, the design loads and associated stresses resulting from rapid closure of the MSIVs and non-return valves will not change. Consequently, SPU does not affect the interface requirements for the MSIVs and non-return valves.

The MSIV bypass valves are used to warm up the main steamlines and equalize pressure across the MSIVs prior to opening the MSIVs. The MSIV bypass valves perform their function at no-load and low-power conditions at which the SPU has no significant effect on main steam conditions (for example, steam flow and steam pressure). Consequently, the SPU does not affect the interface requirements for the MSIV bypass valves.

4.2.2 Steam Dump System

The NSSS Reactor Control Systems and the associated equipment (pumps, valves, heaters, control rods, etc.) are designed to provide satisfactory operation (automatic in the range of 15- to 100-percent power) without reactor trip when subjected to the following load transients:

- Loading at 5 percent of full power per minute with automatic reactor control
- Unloading at 5 percent of full power per minute with automatic reactor control

- Instantaneous load transients of plus or minus 10 percent of full power (not exceeding full power) with automatic reactor control

- Load reductions of 50 percent of full power with automatic reactor control and steam dump

The Steam Dump System creates an artificial steam load by dumping steam from ahead of the turbine valves to the main condenser. The Westinghouse sizing criterion recommends that the Steam Dump System (valves and pipe) be capable of discharging 40 percent of the rated steam flow at full-load steam pressure to permit the NSSS to withstand an external load reduction of up to 50 percent of plant-rated electrical load without a reactor trip. To prevent a trip, this transient requires all NSSS Control Systems to be in automatic, including the Rod Control System, which accommodates 10 percent of the load reduction. A steam dump capacity of 40 percent of rated steam flow at full-load steam pressure also prevents MSSV lifting following a reactor trip from full power.

4.2.2.1 Steam Dump System Major Components

IP3 is equipped with 12 condenser steam dump valves and each valve is specified to have a flow capacity of 505,000 lbm/hr at a valve inlet pressure of 650 psia. The total capacity of the 12 valves provides a steam dump capacity of about 43.8 percent of current rated steam flow 13.26×10^6 lb/hr , or 5.808×10^6 lb/hr at a full load steam pressure of 762 psia (Reference 1).

The capacity of the Steam Dump System (as a percentage of full-load steam flow) decreases as full-load steam pressure decreases and full-load steam flow increases. NSSS operation within the proposed range of design parameters for power uprate will result in a reduced steam dump capability relative to the original Westinghouse sizing criteria. An evaluation indicates steam dump capacity could be as low as 29.4 percent of rated steam flow (13.93×10^6 lb/hr), or 4.10×10^6 lb/hr at a full-load steam pressure equal to 567 psia. At full-load steam pressures higher than 567 psia (T_{avg} = 549°F), steam dump capacity would increase. For example, at a full-load steam pressures of 743 psia (T_{avg} = 572°F), steam dump capacity would be 40.1 percent of rated flow (13.99×10^6 lb/hr), or 5.61×10^6 lb/hr.

The NSSS stability and operability analysis (Section 4.3 of this report) provides an evaluation of the adequacy of the Steam Dump System in conjunction with the control system setpoints at SPU conditions. Subsection 4.3.1 states that the 50-percent load rejection analysis assumes steam dump is available to the condenser, preventing both reactor trip and steam generator safety valve actuation. The analysis results indicated that for full-power T_{avg} values of 564°F and above, the 50-percent load rejection could be accommodated. Therefore, for the full-power T_{avg} value of 567°F at which the plant will operate with the SPU, a 50-percent load rejection can be accommodated. Based on these analyses, the condenser steam dumps meet requirements at SPU conditions as discussed above.

The condenser steam dump valves have NSSS requirements on time for opening and for modulating steam flow. To provide effective control of flow on large step-load reductions or plant trip, the steam dump valves are required to go from full-closed to full-open in 3 seconds at any pressure between 50 psi less than full-load pressure and steam generator design pressure. The dump valves are also required to modulate to control flow. For modulating steam dump flow, the positioning response may be slower with an allowed maximum full-stroke time of 20 seconds. These time response requirements are not affected by the SPU and must still be met.

4.2.3 Condensate and Feedwater System

The C&FS must automatically maintain steam generator water levels during steady-state and transient operations. The range of NSSS design parameters will affect both feedwater volumetric flow and system pressure drop. The volumetric flow may increase by as much as 6.1 percent, or decrease by as much as 3.7 percent and, therefore, system pressure drop may increase by as much as 11.9 percent, or decrease by as much as 4.6 percent during full-power operation. Comparison of the SPU design parameters with the 1.4-percent MUR design parameters indicated that steam generator full-power operating pressure may decrease by as much as 195 psi (762 to 567 psia).

The major components of the C&FS are the main feedwater regulator valves (FRVs), bypass feedwater regulator valves (BFRVs), and the C&FS pumps. Each of these major components is discussed in the sections that follow.

4.2.3.1 Main Feedwater Isolation/FRVs/BFRVs

The main FRVs and BFRVs are located outside containment. The valves function in conjunction with backup trip signals to the feedwater pump discharge isolation valves, feedwater pumps, and other miscellaneous valves to provide redundant isolation of feedwater flow to the steam generators following a steam line break or a malfunction in the steam generator level control system. Isolation of feedwater flow is required to prevent containment overpressurization and excessive RCS cooldowns. Redundant main feedwater isolation is provided by:

- Closure of all the main FRVs and closure of the low-flow feedwater bypass valves, or
- Closure of the main feedwater pump discharge valves that initiate closure of the MFIVs and a trip of the main feedwater pumps.

The quick-closure requirements imposed on the FRVs, BFRVs, and the backup feedwater pump discharge isolation valves causes dynamic pressure changes that may be of large magnitude and must be considered in the design of the valves and associated piping. The worst loads occur following a steam line break from no-load conditions with the conservative assumption that all feedwater pumps are in service providing maximum flow following the break. Since these conservative assumptions are not affected by the SPU, the current design loads and associated stresses resulting from rapid closure of these valves will not change. As noted in Tables 2.1-1 and 2.1-2 in this document, no-load temperature is 547°F. Saturation pressure is 1020 psia at 547°F. This provides the initiating conditions for which the valves would be required to function. The feedwater pumps would provide flow to the steam generators at a pressure sufficient to feed the steam generators with a steam generator pressure of 1020 psia. Since the SPU does not change the no load temperature, the previous analysis remains valid.

4.2.3.2 FRVs, C&FS Pumps

The C&FS available head in conjunction with the FRV characteristics must provide sufficient margin for feed control to ensure adequate flow to the steam generators during steady-state and transient operation. A continuous steady feed flow should be maintained at all secondary system loads. To ensure stable feedwater control with variable speed feedwater pumps, the pressure drop across the FRVs at rated flow (100-percent power) should be approximately equal to the dynamic losses from the feed pump discharge to the steam generator. These dynamic losses include the frictional resistance of feed piping, high-pressure feedwater heaters, feed flow meter, and steam generator. To preclude reactor trip following load rejection, adequate margin should be available in the FRVs at full-load conditions to permit C&FS delivery of 96 percent of rated flow with a 100-psi pressure increase above the full-load pressure with the FRVs fully open. The current Feedwater Pump Speed Control Program results in FRV lift of about 80 percent at T_{avg} of 567°F. A FRV lift of about 80 percent is considered optimum at full load with respect to both valve duty and feedwater control during steady-state and transient operation.

The hydraulic evaluation of the C&FS for the range of design parameters approved for the SPU indicates the lift of the FRVs at full power will increase by as much as 11.3 percent (from 80 to 91.3 percent at T_{avg} of 572°F) with the present Feedwater Pump Speed Control Program. See Section 9.4 of this document for a discussion of the hydraulic evaluation of the C&FS for a large load rejection.

To provide effective control of flow during normal operation, the FRVs are required to stroke open or closed in 20 seconds over the anticipated inlet pressure control range (approximately 0 to 1600 psig). Additionally, rapid closure of the FRVs is required after receiving a trip close signal in order to mitigate certain transients and accidents. These requirements are not affected by the SPU.

4.2.4 Auxiliary Feedwater System

The AFWS supplies feedwater to the secondary side of the steam generators at times when the normal feedwater system is not available, thereby maintaining the steam generator heat sink. The system provides feedwater to the steam generators during normal unit startup, hot standby, and cooldown operations and also functions as an engineered safety feature (ESF). In the latter function, the AFWS is required to prevent core damage and system overpressurization during transients and accidents, such as a loss-of-normal feedwater or a secondary system pipe break. The minimum flow requirements of the AFWS are dictated by accident analyses, and since the SPU affects these analyses, evaluations of the limiting transients and accidents are performed to confirm that the AFWS performance is acceptable at the SPU conditions. These evaluations are described in Section 6 of this report and show acceptable results. Additional discussion of the AFWS is provided in Section 9.12 of this report. The acceptance criteria for the AFWS are discussed in subsection 9.12.4.

4.2.4.1 AFW Storage Requirements

The AFWS pumps are normally aligned to take suction from the condensate storage tank (CST). To fulfill the ESF design functions, sufficient feedwater must be available during transient or accident conditions to enable the plant to be placed in a safe shutdown condition.

The limiting transient with respect to CST inventory requirements is the LOOP transient. The IP3 licensing basis requires that, in the event of a LOOP, sufficient CST useable inventory must be available to bring the unit from full-power to hot-standby conditions, and maintain the plant at hot standby for 24 hours.

Since the required CST inventory is a function of plant-rated power and other NSSS design parameters, a new analysis was performed to determine the required inventory for the range of NSSS design parameters approved for SPU. This analysis is based on the following conservative assumptions:

- Reactor trip occurs from 102 percent of rated core power (3216 MWt), from a low-low water level in the steam generators. A 2-second delay is assumed before reactor trip following LOOP.
- Steam is released from the steam generators at the first safety valve setpoint plus setting tolerance for drift.

- The steam generators are filled back up to 52-percent narrow range water level.

- The CST operating fluid temperature is at the maximum allowable value (120°F).

The analysis concluded that a minimum required useable inventory of 288,500 gallons is required to meet the plant licensing bases for the range of NSSS design parameters approved for SPU. As discussed in Section 9.12, the CST *Technical Specification* requirement of 360,000 gallons ensures a usable volume of 288,500 gallons to meet the limiting design basis requirement.

4.2.5 Steam Generator Blowdown System

The Steam Generator Blowdown System (SGBS) is used to control the chemical composition of the steam generator secondary side water within the specified limits. The SGBS also controls the buildup of solids in the steam generator secondary side.

The blowdown flow rates required during plant operation are based on chemistry control and tube-sheet sweep requirements to control the buildup of solids. The blowdown flow rate required to control chemistry and the buildup of solids in the steam generators is based on allowable condenser in-leakage, total dissolved solids in the plant circulating water, and the allowable primary to secondary leakage. Since these variables are not affected by the SPU, the blowdown required to control secondary chemistry and steam generator solids will not be affected by the SPU.

The inlet pressure to the SGBS varies with steam generator operating pressure. Therefore, as steam generator full-load operating pressure decreases, the inlet pressure to the SGBS control valves decreases and the valves must open to maintain the required blowdown flow rate into the system flash tank. The 1.4-percent MUR NSSS design parameters (Table 2.1-1) evaluate a maximum decrease in steam pressure from no-load to full-load of 258 psi (that is, from 1020 to 762 psia). Based on the revised range of SPU NSSS design parameters, the no-load steam pressure (1020 psia) remains the same, and the minimum full-load steam pressure (567 psia) decreases about 26 percent. As noted in the footnote to Table 2.1-2, steam pressure will be limited to 650 psia during actual operation. This decrease in blowdown system inlet pressure is evaluated in Section 9.5 of this report.

4.2.6 Conclusions

The following is a brief summary of the NSSS/BOP interface evaluation conclusions for the IP3 SPU.

Main Steam System

The capacity of the installed MSSVs meets the original sizing bases for the approved range of NSSS design parameters. The MSSVs are also discussed in Section 9.1 of this report and the capability of the MSSVs is analyzed for the limiting design basis transient (loss-of-load event) in subsection 6.3.6 of this report. The analysis in subsection 6.3.6 demonstrates that the MSSVs are capable of maintaining the secondary side steam pressure below 110 percent of the steam generator shell design pressure.

An evaluation of the installed capacity of the PORVs (2,467,000 lb/hr at 1020 psia) indicates that the original design bases in terms of plant cooldown capability can still be achieved for the range of SPU NSSS design parameters.

The SPU does not affect the design interface requirements for the MSIVs, MSIV bypass valves, and non-return valves.

Steam Dump System

An evaluation of the Steam Dump System indicates that the minimum system capacity is approximately 29 percent of the SPU full-load steam flow at the minimum allowable full-load steam pressure of 567 psia. At full-load steam pressures higher than 567 psia, steam dump capacity would increase. The NSSS stability and operability analysis provides an evaluation of the adequacy of steam dump in conjunction with the control system setpoints (see Section 4.3 of this report). Subsection 4.3.1 states that the 50-percent load rejection analysis assumes steam dump is available to the condenser, preventing both reactor trip and steam generator safety valve actuation. The analysis results indicated that for full-power T_{avg} values of 564°F and above, the 50-percent load rejection could be accommodated. Therefore, for the full-power T_{avg} value of 567°F at which the plant will operate with the SPU, a 50-percent load rejection can be accommodated. Based on these analyses, the condenser steam dumps meet requirements at SPU conditions as discussed above.

Condensate and Feedwater System

The hydraulic evaluation of the C&FS for the range of design parameters approved for the SPU indicates the lift of the FRVs at full power will increase by as much as 11.3 percent (from 80 to 91.3 percent at T_{avg} of 572°F) with the present Feedwater Pump Speed Control Program. See Section 9.4 of this document for a discussion of the hydraulic evaluation of the C&FS for a large load rejection.

Auxiliary Feedwater System

The AFWS is capable of delivering the minimum flow requirements for the SPU (see Section 6 of this report).

The CST minimum useable inventory of 288,500 gallons is required to meet the plant licensing bases for the range of NSSS design parameters approved for SPU. The current *Technical Specification* value of 360,000 gallons ensures a usable volume of 288,500 gallons.

Steam Generator Blowdown System

The blowdown flow required to control secondary chemistry and steam generator solids is not affected by the SPU.

4.2.7 References

1. *Indian Point Nuclear Generating Unit No.3 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, Entergy Nuclear Operations, Inc., May 2002.

2. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition with Winter 1965 Addenda, The American Society of Mechanical Engineers, New York, NY.

3. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

4.3 Nuclear Steam Supply System Control Systems

4.3.1 NSSS Stability and Operability

4.3.1.1 Introduction

Control systems operability analyses were performed on the Nuclear Steam Supply System (NSSS) control system setpoints for the Indian Point Unit 3 (IP3) plant to determine that there is adequate margin to relevant reactor trip and engineered safety features (ESFs) actuation setpoints for the proposed stretch power uprate (SPU). The conditions that were used as starting points for these analyses are provided in Section 2 of this report (NSSS parameters) and encompass a range of plant operating conditions.

The following cases, at both high- and low-T_{avg} conditions, were analyzed:

- Fifty-percent load rejection from 100-percent power
- Ten-percent step-load decrease from 100-percent power
- Ten-percent step-load increase from 90-percent power
- Turbine trip without reactor trip

4.3.1.2 Input Parameters and Assumptions

The conditions that were used as starting points for these analyses are provided in Section 2 of this report and encompass a range of plant operating conditions. However, the steam pressure for the low T_{avg} conditions shown in Section 2 was not able to be supported by the NSSS design transient analyses described in Section 3.1 of this report. The minimum full-power steam pressure that could be supported was a value of 650 psia (due to steam generator tubesheet ΔP considerations). This resulted in the following full-power T_{avg} values for this minimum acceptable full-power steam pressure:

Zero-percent steam generator tube plugging (SGTP):	Full-power T_{avg} = 550.6°F
Ten-percent SGTP:	Full-power T_{avg} = 563.7°F

The stability and operability analyses bracketed all operating conditions: full-power T_{avg} ranging from the above minimum values for a minimum full-power steam pressure of 650 psia to an upper limit of 572.0°F, and 0- to 10-percent SGTP levels. The following assumptions were made for all normal transients analyzed:

- All applicable NSSS control systems were assumed to be operational and in the automatic mode of control (that is, rod control, steam dump control, pressurizer level, steam generator level control, and pressurizer pressure control).

- Two-percent initial power level uncertainty was assumed. The remainder of the plant parameters (that is, Reactor Coolant System [RCS] T_{avg}, pressurizer pressure, pressurizer level, steam generator level) were assumed to be at their nominal control system setpoints.

- Best-estimate reactor kinetics parameters were modeled (that is, rod worth, moderator temperature coefficient [MTC], Doppler power defect, etc.) Since beginning-of-life (BOL) core physics parameters have lower differential rod worth and a less negative MTC, modeling BOL core characteristics typically yielded more conservative results that bound the full cycle of operation.

- In general, analysis of 10-percent SGTP conditions bounds the 0-percent tube plugging conditions. Higher SGTP was somewhat more conservative for short-term heatup transients due to a slower rate of heat transfer from the primary to secondary side of the plant. Furthermore, lower nominal steam temperatures and pressures reduced steam dump capacity during heatup transients, and reduced margin to safety injection (SI) actuation on low steam pressure during cooldown transients.

- The transient simulations were modeled to run for a 500-second interval (about 8 minutes). Most challenges to the reactor trip and ESF actuation setpoints occurred within the first minute of the design basis normal condition transients, therefore this simulation time frame was considered more than adequate for assessing control system response and stability considerations.

- The following protection systems functions have the greatest potential for being challenged during these operability transients and therefore were considered in this analysis (other protection systems would only be challenged during these transients if one of the following did not function).

Overtemperature ΔT

$$\Delta T\left[\frac{1}{(1+\tau_4 s)}\right] \le \Delta T_0 \{K_1 - K_2\left[\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\right]\left(T\left[\frac{1}{(1+\tau_5 s)}\right] - T'\right) + K_3(P-P') - f_1(\Delta I)\}$$

Parameter	Setpoint
K_1	1.22
K_2	0.022/°F
K_3	0.0007/psi
τ_1	25 sec
τ_2	3 sec
τ_4	0 sec (not shown in Technical Specifications since value is 0.0)
τ_5	0 sec (not shown in Technical Specifications since value is 0.0)
ΔT_0	Indicated ΔT at rated thermal power (RTP), °F
T	Measured RCS T_{avg}, °F
T'	Reference T_{avg} at RTP, °F
P	Measured pressurizer pressure, psig
P'	Nominal RCS operating pressure, psig
ΔT	Measured ΔT, °F
$f_1(\Delta I)$	= [*] {[*] - (q_t - q_b)} when (q_t - q_b) < [*] RTP = 0.0 of RTP when [*] RTP < (q_t - q_b) < [*] RTP = [*] {(q_t - q_b) - [*]} when q_t - q_b > [*] RTP Where q_t and q_b are fraction RTP in the upper and lower halves of the core, respectively, and q_t + q_b is the total THERMAL POWER in fraction RTP.

*These values denoted with [*] are specified in the *Core Operating Limit Report* (COLR).

Overpower ΔT

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

Parameter	Setpoint
K_4	1.074
K_5	0.0175/°F
K_6	0.0015/°F
τ_3	10 sec
τ_4	0 sec (not shown in Technical Specifications since value is 0.0)
τ_5	0 sec (not shown in Technical Specifications since value is 0.0)

ΔT_0	Indicated ΔT at RTP, °F
T'	Reference T_{avg} at RTP, °F
ΔT	Measured ΔT, °F

High-pressurizer pressure reactor trip:	2365 psig
Low-pressurizer pressure reactor trip:	1930 psig
Lead time constant:	9 seconds
Lag time constant:	1 second
Low-pressurizer pressure SI:	1780 psig
High steamline flow SI	54-percent flow from 0 – 20 percent load, linearly increasing to 120-percent flow at 100-percent load
Low steamline pressure:	616 psig
Low T_{avg}:	542°F

These assumptions were used as inputs for the analyses in the following subsections. These subsections describe in greater detail each of the transients analyzed.

4.3.1.3 Fifty-Percent Load Rejection from Full-Power Transient

4.3.1.3.1 Description of Analysis and Evaluations

A 50-percent load rejection with steam dump transient was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the 50-percent load rejection transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The 50-percent load rejection is the most severe operational transient that the plant would normally undergo without a reactor trip. The transient was modeled as a turbine runback from 100- to 50-percent power, at a maximum rate of 200-percent per minute. The 200-percent-per-minute transient is the fastest unloading rate that the turbine can normally perform, so this was used in the analyses.

The RCS average temperature, RCS and pressurizer pressure, and secondary side steam pressure increased rapidly following this transient initiation. The steam dump was available to the condenser, preventing both reactor trip and steam generator safety valve actuation. All NSSS control systems were available to mitigate this transient.

4.3.1.3.2 Acceptance Criteria

The 50-percent load rejection from full power should provide adequate margins to the nominal trip setpoints (see subsection 4.3.1.2). The plant response should be stable and non-oscillatory. There should be adequate pressurizer PORV capacity to prevent the transient from reaching the high-pressurizer pressure reactor trip setpoint.

4.3.1.3.3 Results

The initial analyses were performed for the low T_{avg} range of operation as noted in subsection 4.3.1.2. While the results showed margin was needed for the overtemperature ΔT (OTΔT) trip setpoint (limiting protection system function), at the lower limiting T_{avg} of 550.6°F, as the full-power T_{avg} is increased to the range expected for future SPU operations, larger load rejections can be successfully handled without resulting in a reactor trip. The analyses results indicated that, for full-power T_{avg} values of 564°F and above, the 50-percent design basis load rejection could be accommodated. Therefore, for the full-power T_{avg} value of 567°F at which the plant will operate with the SPU implementation, a 50-percent load rejection can be accommodated.

As the full-power T_{avg} value is increased, the load rejection transient becomes less limiting. This is due to a combination of reasons:

- Higher values of T_{avg} result in more of an initial temperature error to the steam dump control logic, thereby increasing the initial steam dump opening.
- Higher values of T_{avg} result in higher steam pressures, thereby increasing the steam dump flow for a given steam dump valve position.
- Higher values of T_{avg} result in a more negative value of the fuel MTC, thereby producing greater fuel reactivity effects to mitigate the transient.

The control system response was smooth during the transient with no oscillatory response noted. All parameters responded smoothly with no sustained or divergent oscillations.

The peak-pressurizer pressure was controlled by the pressurizer power-operated relief valve (PORV) actuation, thereby preventing the pressurizer pressure from reaching the high-pressurizer pressure reactor trip setpoint and showing acceptable capacity for the pressurizer PORVs. The peak steam pressure was no higher than the no-load steam pressure, so the steam generator atmospheric relief valves (ARVs) were not challenged.

In summary, the 50-percent load rejection transient can be successfully accommodated when the T_{avg} is 564°F or higher.

4.3.1.4 Ten-Percent Step-Load Decrease from Full-Power Transient

4.3.1.4.1 Description of Analysis and Evaluations

A 10-percent step-load decrease from full-power transient was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the 10-percent step-load decrease transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The 10-percent step-load decrease was initiated from 100-percent power. Secondary side steam pressure and temperature initially increased, lagged by an increase in the primary side average temperature (T_{avg}) and RCS pressure. The power mismatch between the turbine load and nuclear power, and the resultant temperature error between the T_{avg} and reference temperature (T_{ref}) caused the rods to move into the core, reducing core power. Reactor coolant temperature and pressure were then restored to their equilibrium values.

This transient should not result in the pressurizer pressure reaching the pressurizer PORV actuation setpoint. Stability of the Rod Control System was also assessed.

4.3.1.4.2 Acceptance Criteria

During the 10-percent step-load decrease transient, the PORV actuation setpoint should not be challenged. Therefore, the maximum pressure reached during this transient should be below the PORV actuation setpoint of 2350 psia (2335 psig).

4.3.1.4.3 Results

This transient is the same one that was used to verify acceptability of the pressurizer spray capacity in subsection 4.3.2 in this report. The analyses performed for the spray capacity included additional conservatisms not normally used in the plant operability analyses (that is, T_{avg} uncertainty of 7.5°F), and therefore bracketed the best-estimate analyses normally used in the plant operability analyses. The results indicated that no reactor trip setpoints were challenged and the control system response was stable and non-oscillatory. Pressurizer pressure reached a maximum of 2332 psia (2317 psig) for the high T_{avg} case and the PORVs were not challenged. Therefore, the plant response for the 10-percent step-load decrease transient is acceptable for the SPU.

4.3.1.5 Ten-Percent Step-Load Increase from 90-Percent Power Transient

4.3.1.5.1 Description of Analysis and Evaluations

A 10-percent step-load increase from 90-percent power transient was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the 10-percent step-load increase transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The 10-percent step-load increase was initiated from 90-percent power. Secondary steam pressure and temperature decreased initially, followed by a decrease in the primary side T_{avg} and pressurizer pressure. Pressurizer heaters are actuated to restore system pressure. The power mismatch between the turbine load and nuclear power, and the resultant temperature error between T_{avg} and T_{ref} would cause the rods to move out of the core, increasing core power until the final 100-percent power condition is reached.

Since the 10-percent step-load increase transient will result in the lowest steam pressure of any of the operational transients, it is analyzed in order to demonstrate that ESF actuation will not occur on low steam pressure.

4.3.1.5.2 Acceptance Criteria

The 10-percent step-load increase was analyzed to demonstrate that ESF actuation would not occur due to the plant cooldown. The critical function is the ESF actuation on high steamline flow coincident with low steamline pressure (616 psig or 631 psia) or low T_{avg} (542°F). While the transient will not actuate the high steamline flow trip setpoint at 100-percent power, partial actuation of the other functions could occur. Analyses were performed at the lower range of T_{avg} since this operating condition has the lowest margin to the low steamline pressure or low T_{avg} setpoints. The limiting case is for the minimum full-power steam pressure of 650 psia, the 0-percent SGTP conditions that resulted in a minimum full-power T_{avg} of 550.6°F.

4.3.1.5.3 Results

The results for the limiting case, in which the full-power T_{avg} is 550.6°F with a minimum full-power steam pressure of 650 psia and 0-percent SGTP conditions, indicated that the plant would experience a plant cooldown. The minimum T_{avg} was 545°F, which is just above the low T_{avg} setpoint of 542°F portion of the high-steamline flow ESF function. The minimum steam pressure was 612 psia, below the low-steam pressure setpoint of 631 psia portion of the high steamline flow ESF function. The RCS cooldown was enough to potentially result in shutoff of the pressurizer heaters since the level dropped to 18.3-percent, just above the low-level heater cutoff setpoint of 18-percent of span. The 10-percent step-load increase transient was also performed at a full-power T_{avg} of 567°F, which resulted in a RCS cooldown but there was greater margin to the various functions except the low-steamline pressure portion of the high steamline flow ESF function. For this case, the minimum steam pressure reached was 628 psia, which is just below the low-steamline pressure setpoint of 631 psia; however, the Engineered Safety Feature Actuation System (ESFAS) actuations are partial actuations that require a high-steamline flow measurement, which will not be reached during this transient. Also, for this case, the pressurizer level drops due to the cooldown but remains above the low-level heater cutoff setpoint of 18-percent of span.

4.3.1.6 Turbine Trip without Reactor Trip from P-8 Setpoint or Below

4.3.1.6.1 Description of Analysis and Evaluations

A turbine trip without reactor trip transient from the P-8 setpoint or below was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the turbine trip transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The turbine and reactor trip logic was coupled with the P-8 permissive. If a turbine trip occurs from a power level above the P-8 permissive, the turbine trip would actuate a reactor trip. If a turbine trip occurs from a power level at or below the P-8 permissive, no immediate reactor trip would occur. The nominal analysis value for the P-8 setpoint was 35-percent power, but analyses were also performed below the P-8 setpoint, at 20-percent power. Therefore, a turbine trip without reactor trip transient (that is, turbine trip from power level at or below the P-8 setpoint) can be considered as being a load rejection, and the 50-percent load rejection analyses described in subsection 4.3.1.3 of this report would cover this transient. However, another acceptability requirement of this transient is that the pressurizer PORVs are not actuated. This requirement is the limiting requirement for transient acceptability.

4.3.1.6.2 Acceptance Criteria

The turbine trip without reactor trip transient from the P-8 setpoint or lower power level should provide adequate margins to the nominal trip setpoints (see subsection 4.3.1.2). The plant response should be stable and non-oscillatory. The pressurizer PORVs should not be actuated during this transient. While not a requirement, it is desirable that the steam generator ARVs are not challenged during this transient.

4.3.1.6.3 Results

The following assumptions were made besides those described in subsection 4.3.1.2.

- The Rod Control System was assumed to be in manual; no credit was taken for rod motion.

- The analyses were performed for both the 0-percent SGTP (full-power T_{avg} = 550.6°F) and 10-percent SGTP (full-power T_{avg} = 563.7°F) cases for the minimum acceptable full-power steam pressure of 650 psia. Normally, the higher SGTP case is limiting, but the lower SGTP case would have the lower (T_{avg} - $T_{no\ load}$) signal to the steam dump valves and, therefore, the greater amount of plant heatup (and resulting higher pressurizer insurge and peak pressurizer pressure). Analyses for these low extremes of full-power T_{avg} would bound the results for higher values of T_{avg}.

The turbine trip without reactor trip analyses from 35-percent power (that is, the P-8 setpoint) showed unacceptable results (that is, there was not adequate margin to the PORV actuation setpoint) for the 0-percent STGP case; however, the analyses from 20-percent power showed acceptable results. For the 10-percent SGTP case, the turbine trip without reactor trip analyses showed acceptable results from both 35-percent power and 20-percent power, where the peak-pressurizer pressures were 2317 and 2304 psia, respectively.

The above analyses were performed at the lower limiting T_{avg} values for plant operation at the minimum acceptable full-power steam pressure of 650 psia. As the full-power T_{avg} (and consequentially the full-power steam pressure) was raised above this lower limit, the peak-pressurizer pressure was reduced. Therefore, a turbine trip without reactor trip transient is acceptable with the P-8 setpoint set to 20-percent power for T_{avg} values of 550.6°F and above, or with the P-8 setpoint set to 35-percent power for T_{avg} values of 564°F and above. A P-8 setpoint of 35-percent power is acceptable for the full-power T_{avg} value of 567°F, at which the plant will operate for the SPU implementation.

4.3.1.7 Conclusions of the Control Systems Operability Analyses

The control systems operability analyses were performed for the entire full-power T_{avg} window (see subsection 4.3.1.2); however, the plant will operate at a full power T_{avg} of 567°F following the SPU implementation. The following was concluded from the plant operability analyses performed for this expected 567°F operating point:

The 10-percent step-load decrease transient can be accommodated successfully without challenging the pressurizer PORVs for the full-power T_{avg} window.

The 10-percent step-load increase transient can be accommodated successfully without challenging any reactor trip setpoints for full-power T_{avg} values of 564°F and above. The low-steamline pressure portion of the high steamline flow ESF actuation could be actuated while performing this transient with a full-power T_{avg} of 564°F or higher; however, the ESFs actuations are partial actuations that require a high steamline flow coincident measurement, which will not be reached during this transient.

The 50-percent load rejection can be successfully accommodated for full-power T_{avg} values of 564°F and above.

The turbine-trip-without-reactor trip from a power level corresponding to the P-8 setpoint or lower can be successfully accommodated with the P-8 setpoint set to 35-percent power for full-power T_{avg} values of 564°F and above.

The control systems are stable and support the SPU for all normal condition transients; no long-term, continuous, or diverging plant parameter oscillations were noted during any of the operational transients.

4.3.2 Pressurizer Pressure Control System Component Sizing

The various NSSS pressure control components are intended to maintain the pressurizer pressure at the nominal setpoint during steady-state operation, and to control the pressure excursions that occur during design basis transients to an extent that a reactor trip, ESFAS actuation, or a pressurizer safety valve actuation would not occur. This assessment shows that the installed capacity of the various pressure control components remains acceptable for the SPU conditions.

The following pressure control components were evaluated:

- Pressurizer heaters
- Pressurizer spray valves
- Pressurizer PORVs

4.3.2.1 Pressurizer Heaters

The pressurizer heaters are sized to be able to heat up the pressurizer liquid at a 200°F/hr rate during the initial plant heatup phase from cold shutdown. In addition, they are intended to assist the plant in controlling the pressurizer pressure decrease that would occur during design basis transients that result in pressurizer outsurge events. These include the initial part of a 10-percent step-load increase transient, a 5-percent-per-minute-plant-unloading transient, or events resulting in a reactor trip. The design basis pressurizer heater capacity is 1 kW of heater capacity per cubic foot of pressurizer free volume. Generic analyses on Westinghouse plants have shown that the pressurizer heater capacity is not a strong influence on the minimum pressure noted during the above operational events or during reactor trips. The minimum pressure is controlled by the outsurge that results during the transient. Analyses have been performed in which the pressurizer heater capacity has been reduced by as much as 20 percent, and no major difference has been observed in the analysis results. The heatup time from cold shutdown to hot standby was not affected by the SPU. The heatup maneuver would be essentially the same as that which IP3 presently experiences. Therefore, the installed pressurizer heater capacity meets the acceptance criterion at the SPU conditions.

4.3.2.2 Pressurizer Spray

The design basis for the pressurizer spray capacity is that it is able to handle a 10-percent step-load decrease transient without resulting in the pressure increasing to the pressurizer PORV setpoint. The limiting case is a 10-percent step-load decrease from 100- to 90-percent power.

The SPU power rating would tend to increase the demand on the pressurizer spray. Therefore, the pressurizer spray sizing was analyzed to ensure acceptability. The analysis included the following assumptions:

- The plant is initially at 102 percent (100-percent nominal power with 2-percent uncertainty) of the 3230-MWt SPU NSSS power level.
- The plant is initially at nominal T_{avg} + 7.5°F uncertainty.
- The transient is a step-load reduction from the noted 102-percent turbine load to 90-percent load.
- Initial pressurizer pressure is at nominal pressure of 2250 psia.
- The initial pressurizer water level is at nominal values.
- The steam generator heat transfer coefficient increases to the maximum credible value (0-percent fouling, 0-percent SGTP).
- Best-estimate nuclear design parameters (moderator temperature coefficient, Doppler power defect, control rod worth, and startup data) are at conservative BOL conditions.

- Credit is taken for automatic operation of all normally functioning NSSS control systems (reactor control, pressurizer pressure and level control, and feedwater control; steam dump is not credited for a 10-percent step-load transient).

- The installed spray capacity analyzed is 325 gpm/valve for a total of 650 gpm.

The limiting case is for the plant operating at the upper limit T_{avg} of 572°F. For this case, the peak pressurizer pressure was 2332 psia, which is below the pressurizer PORV setpoint of 2350 psia. Therefore, the installed pressurizer spray capacity meets the acceptance criterion at the SPU conditions.

4.3.2.3 Pressurizer PORVs

The design basis for the pressurizer PORV capacity is to be able to handle a 50-percent load decrease transient without resulting in the pressure increasing to the high-pressurizer pressure reactor trip setpoint. The limiting case is a 50-percent load decrease from 100- to 50-percent power at 200 percent per minute.

The pressurizer PORV sizing analysis was performed at the IP3 SPU operating conditions defined in Section 2.1. The analysis was intended to bracket the window of operating conditions, a full-power T_{avg} of 549° to 572°F, and 0- to 10-percent SGTP levels. However, at the lower end of the T_{avg} window (that is, 549°F), the corresponding full-power steam pressure of 591 psia (Table 2.1-2) would violate the minimum acceptable full-power steam pressure of 650 psia that is required to avoid violating the primary-to-secondary pressure differential of 1700 psid. Thus, this PORV sizing analysis brackets the following window of operating conditions, with full-power T_{avg} ranging from 550.6° to 572°F, and 0- to 10-percent SGTP levels.

With the SPU NSSS power of 3230-MWt, the demand on the pressurizer PORVs would tend to increase. Therefore, the pressurizer PORV sizing was analyzed to ensure acceptability. The analysis included the following assumptions:

- The plant is initially at 102 percent (100-percent nominal power with 2-percent uncertainty) of the 3216-MWt SPU power level.

- The plant is initially at nominal T_{avg} + 7.5°F uncertainty.

- The transient is a load decrease from the noted 102-percent turbine load to 50-percent load at 200-percent per minute.

- The initial pressurizer pressure is at nominal pressure of 2250 psia.

- The initial pressurizer water level is at nominal values.

- The steam generator heat transfer coefficient increases to the maximum credible value (0-percent fouling, 0-percent SGTP).

- The fuel reactivities are at conservative BOL conditions.

- Credit is taken for automatic operation of all NSSS control systems (reactor control, pressurizer pressure and level control, feedwater control, and steam dump control).

- The installed PORV capacity analyzed is 179,000 lb/hr per PORV.

The limiting case for this sizing analysis occurs for the plant operating at the upper limit T_{avg} of 572°F. For this case, the pressurizer PORVs had sufficient capacity to avoid the pressurizer pressure from rising to the implemented high-pressurizer pressure reactor trip setpoint of 2377 psia.

The 50-percent step-load decrease was modeled as a 50-percent load rejection at a maximum turbine-unloading rate of 200-percent/minute. With this modeling, the pressurizer PORV capacity was sufficient to avoid a reactor trip on high-pressurizer pressure.

4.3.2.4 Conclusions

Based on this review, the existing pressurizer pressure control component sizing (pressurizer heaters, spray, and PORVs) meets the acceptance criterion at the SPU conditions.

4.3.3 Overpressure Protection System

As a result of the IP3 SPU, the plant operating parameters have changed from the present licensed parameters. The affected parameters are shown in Table 2.1-2. These are at-power parameters. However, the Overpressure Protection System (OPS) only comes into operation during zero-power operation during plant heatup, cooldown, or any operation between cold shutdown and hot standby.

The OPS setpoints would only be required to be evaluated and potentially revised for reasons such as:

- Changes in the design basis transients for which the OPS provides protection (that is, changes in the design basis mass input or heat input transients). There are no changes in the design basis transients.

- Appendix G pressure-temperature (P-T) limit changes in the adverse direction. Note that a change in the effective full-power years (EFPYs) applicable to the P-T limits does not constitute a reason to revise the setpoints; only an adverse change in the P-T limits themselves would warrant a setpoint re-analysis. There are no changes in the P-T limits.

- Some physical component in the plant changes that affects the performance of the OPS (for example, steam generator replacement, different pressurizer PORV stroke time or flow characteristic, different charging, or SI pump with a revised head/flow curve). The one analysis difference is in the design value of the SGTP level, which is being revised to 10 percent for the SPU (see Table 2.1-2 of this report) versus the present 25-percent tube plugging level (see Table 2.1-1 in Section 2 of this report). Therefore, the existing analyses for the 0- to 25-percent tube plugging level bracket the SPU 0- to 10-percent plugging level.

Based on this review, the installed OPS setpoints are not affected by the SPU.

4.3.4 IP3 SPU Instrumentation and Control Systems

4.3.4.1 Introduction

The Reactor Trip System (RTS), Engineered Safety Feature Actuation System (ESFAS), and NSSS Auxiliary System instrumentation have been reviewed to identify changes to setpoints, time constants, logic matrices, electrical power requirements, hardware, separation requirements, and cable routing.

4.3.4.2 I&C Instrumentation Hardware Change

The RTS and ESFAS were reviewed for hardware and other changes.

The following NSSS Auxiliary Systems were reviewed for hardware and other changes:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Residual Heat Removal System (RHRS)
- Safety Injection System (SIS)
- Containment Spray System (CSS)
- Component Cooling Water System (CCWS)
- Service Water System (SWS)

- Spent Fuel Pit Cooling System (SFPCS)
- Primary Sampling System (PSS)
- Emergency Diesel Generator (EDG) Loading System

4.3.4.3 Equipment Environmental Qualification

Environmental qualification (EQ) (temperature, pressure, and humidity) of hardware to be replaced due to the SPU was addressed.

4.3.4.4 Equipment Seismic Qualification

There is no credible reason that the SPU would adversely affect the seismic qualification of existing safety-related equipment. Therefore, the seismic qualification documentation for the existing safety-related equipment is not changed due to the SPU.

4.3.4.5 Instrumentation Settings and Setpoint Changes

The following settings, setpoints, hardware, and other changes are due to the SPU

- "K constants" (values for the overtemperature ΔT/overpower ΔT [OTΔT/OPΔT] setpoint equations)

- Steam flow transmitters

- Steam flow channel

- Turbine pressure

- Turbine pressure transmitters

- Low-pressurizer pressure trip lead/lag values

The safety functions associated with the above changes are not adversely affected.

4.3.4.6 Conclusions

The SPU will require changes to some NSSS instruments and control systems setpoints, time constants, and hardware. However, logic matrices, separation requirements, cable routing, electrical power requirements, and the system safety functions are not required to be changed as a result of the SPU. The setpoint/scaling and time constant changes associated with the SPU are within the capability of the instrumentation. Implementation of the identified changes (hardware, setpoints, re-span, re-calibrate, etc.) configures the instruments and control systems to support the SPU operation. The instrument and control system instrumentation changes have been shown to be acceptable for the SPU.

4.3.5 References

1. WCAP-7878, *LOFTRAN Code Description*, Rev. 6, G. E. Heberle, February 2003.

5.0 NUCLEAR STEAM SUPPLY SYSTEM COMPONENTS

Evaluations were performed to determine the effects of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) parameters on the Nuclear Steam Supply System (NSSS) components. In general, the SPU-related inputs used for these evaluations are the Performance Capability Working Group (PCWG) parameters (refer to Section 2) and the NSSS design transient changes (found in Section 3.1). Additional input parameters specific to particular components (for example, NSSS auxiliary equipment design transients for the auxiliary equipment evaluations) were considered and are discussed in the appropriate component evaluation section. The purpose of the evaluations performed for the NSSS components was to confirm that they continue to satisfy the applicable codes, standards, and regulatory guides under the SPU conditions.

Evaluations were performed in the following areas, and are described within the remainder of this section:

- Reactor vessel structural integrity
- Reactor pressure vessel (RPV) system
- Control rod drive mechanisms (CRDMs)
- Reactor coolant loop (RCL) piping and supports
- Reactor coolant pumps (RCPs) and motors
- Steam generators
- Pressurizer
- NSSS auxiliary equipment
- Fracture integrity of NSSS components
- Additional materials considerations for the Reactor Coolant System (RCS)

5.1 Reactor Vessel

5.1.1 Reactor Vessel Structural Integrity

5.1.1.1 Introduction

Evaluations were performed for the Indian Point Unit 3 (IP3) reactor vessel (RV) to determine the stress and fatigue usage effects of Nuclear Steam Supply System (NSSS) operation at the revised operating conditions for the stretch power uprate (SPU).

5.1.1.2 Input Parameters and Description of Evaluation Performed

The RV structural evaluation assesses the effects of the revised operating parameters in Table 2.1-2 and RCS transients (see Section 3.1) on the most limiting locations with regard to ranges of stress intensity and fatigue usage factors in each of the regions as identified in the RV stress report and addendum. Prior to the SPU evaluation, the most recent vessel structural evaluation for IP3 was performed for the Measurement Uncertainty Recapture (MUR) Program. The design and operating parameters for the reactor vessel are revised as a result of the SPU in accordance with Table 2.1-2. The minimum vessel inlet temperature decreases from 542.2° to 517.3°F, thereby increasing the T_{cold} variations for plant loading and unloading transients. The SPU maximum vessel outlet temperature of 603.0°F is bounded by previous analyses, therefore not affecting the plant loading or unloading transients.

In addition, other design transients were judged more severe than their design basis counterparts. Loss-of-flow, one pump required consideration for the regions affected by T_{hot} in the SPU evaluation. Loss-of-load (LOL) and loss-of-flow, one pump in addition to plant loading and unloading required consideration for regions influenced by T_{cold}. Three pressure variations from the following transients also required consideration in the evaluation: step-load rejection, loss-of-flow, one pump, and reactor trip.

In addition to the above transient revisions, the evaluation also considered additional occurrences of the hydro-static test at 2500 psia for the RV. This was done to supplement the original stress report, which only considered 5 occurrences of hydro-static tests to ASME Section XI pressure test requirements subsequent to commercial operation. These pressure tests are known to occur more frequently than once every 8 to 10 years. Therefore, the evaluation considered at least 200 occurrences of the hydro-static test in the maximum cumulative usage factor (CUF) calculation for each RV region.

The revised RV and RV internals interface loads developed for the SPU were evaluated to ensure that they were acceptable.

The parameter cases in Table 2.1-2, the design transients discussed in Section 3.1, and the current design basis parameters and design transients are fully evaluated for the SPU. Reactor vessel operation in accordance with the IP3 SPU conditions is justified for the remainder of the operating license period.

5.1.1.3 Acceptance Criteria and Results of Evaluations

The acceptance criteria applicable to the evaluation are as follows:

- The maximum range of stress intensity must be less than three times the design stress intensity ($3S_m$) for each location.

- The cumulative fatigue usage factor must be less than unity (CUF < 1) for each location.

The RV main closure flange assembly, control rod drive mechanism (CRDM) housings, head adapter plugs, and outlet nozzles were evaluated for the effects of the increased T_{hot} variation during the transient for loss-of-flow, one pump. For regions affected by T_{hot} conditions, the maximum range of primary plus secondary stress intensity reported in the previous structural evaluation remain unchanged for the SPU. The CRDM housings are the only T_{hot} region that sees an increase in CUF, which is a slight increase to 0.124. The CUFs for other T_{hot} regions remain unchanged for the SPU.

The inlet nozzles, vessel wall transition, bottom head-to-shell juncture, core support pads, and instrumentation tubes were evaluated for the effects of the T_{cold} variations during transients for LOL, loss-of-flow, one pump, and plant loading and unloading. The vessel wall transition, core support pads, bottom head-to-shell juncture and instrumentation tubes all show slight increases in maximum ranges of stress intensity for the SPU. The maximum range of stress intensity for the inlet nozzles remains unchanged for the SPU. The CUF for the inlet nozzles, vessel wall transition, bottom head-to-shell juncture, and instrumentation tubes show slight increases, but remain well below the allowable limit for the SPU. The CUF for the core support pads remains unchanged for the SPU. The stress range and CUF results from this evaluation are summarized in Table 5.1-1.

The interface seismic and loss-of-coolant accident RV and reactor internal (LOCA RV/RI) loads for the IP3 SPU are all less than the corresponding faulted condition loads that have previously been considered in the IP3 RV stress report. Therefore, the loads are acceptable.

5.1.1.4 Conclusions

The maximum ranges of stress intensity are less than the allowable limit of $3S_m$ for all locations of the reactor vessel. The cumulative fatigue usage factors are less than unity for all locations, and the faulted condition interface loads are less than loads used in previous evaluations. In summary, the limits defined in the American Society of Mechanical Engineers (ASME) Section III (References 1 and 2) are satisfied and the SPU will not compromise the structural integrity of the IP3 RV.

5.1.2 RV Integrity

RV integrity is affected by any changes in plant parameters that affect neutron fluence levels or temperature and pressure transients. The neutron fluence projections resulting from the IP3 SPU have been evaluated to determine the potential effect on RV integrity. Typically, such an evaluation is performed by direct comparison of the neutron fluence projections from the analyses of record to the SPU neutron fluence projections. However, prior to the IP3 SPU, Westinghouse revised the current RV integrity analyses of record for IP3 as a part of the MUR Program. The only exception is the pressure-temperature limits, which were updated after the MUR Program. The updated reactor vessel integrity evaluations used neutron fluence projections that correspond to 3068 MWt. As such, the evaluations for the SPU discussed below build on the most recent analyses. More specifically, that includes the following evaluations:

- Assessment of the RV surveillance capsule removal schedule to confirm that the SPU fluence projections do not change the required number of capsules to be withdrawn from the IP3 RV.

- Review of the P-T limit curves to determine if the vessel fluence projections based on the SPU affect the applicability date.

- Review of the RT_{PTS} values to determine if the effects of the SPU fluence projections resulted in an increase in RT_{PTS} for the beltline materials in the IP3 RV at 27.1 effective full-power years (EFPYs), which is the estimated end of license (EOL).

- Review of the upper shelf energy (USE) values at 27.1 EFPY, which is the estimated EOL, to assess the effect of the SPU fluence projections.

The calculated fluences used in the SPU evaluation comply with Regulatory Guide (RG) 1.190 (Reference 3). These calculations are performed on a plant-specific basis, consistent with the methodology in RG 1.190. The net result of the SPU was an increase in projected fluence as compared to the MUR Program fluence projections. This increased SPU fluence is the basis for the conclusions provided in the following subsections.

5.1.2.1 Surveillance Capsule Withdrawal Schedule

The revised SPU fluence projections have been used in the assessment of the current withdrawal schedule for IP3. A calculation of ΔRT_{NDT} at 27.1 EFPYs was performed to determine the number of capsules to be withdrawn for IP3. This calculation determined that the maximum ΔRT_{NDT} using the SPU fluences corresponding to 3216 MWt for IP3 at 27.1 EFPYs is greater than 200°F. These ΔRT_{NDT} values would require 5 capsules to be withdrawn from IP3 (Reference 4). This is consistent with the current withdrawal schedule. However, since the RV fluence projections increased, the withdrawal times are affected. The new withdrawal schedule is presented in Table 5.1-2.

5.1.2.2 Applicability of Heatup and Cooldown P-T Limit Curves

The IP3 *Technical Specifications* contain P-T limit curves for 34.7 EFPYs. These P-T limit curves were based on fluence values that correspond to a power level between 3068 and 3216 MWt. Therefore, the existing heatup and cooldown curves for 34.7 EFPY must be reduced to account for the higher fluence projections for the SPU. The reduced EFPY was determined by calculating the equivalent SPU EFPY that corresponds to the peak fluence used for the existing PT curves (1.13×10^{19} n/cm^2). This is normally a simple interpolation calculation. However, the fluence used to generate the existing PT curves is exactly equal to the SPU fluence projection at 34.0 EFPY. Thus, the applicability of the existing PT curves has been reduced 0.7 EFPY, to 34 EFPY (0.7 EFPY is equivalent to 8 months of operation).

5.1.2.3 Emergency Response Guideline Limits

The limiting material for IP3 is the lower shell plate B2803. The current peak inside surface RT_{NDT} value at 27.1 EFPY (EOL) associated with this material was calculated to be 262°F (see Table 5.1-3). The resulting Emergency Response Guidelines (ERG) category (see Table 5.1-4) is unchanged from the previous evaluation for the MUR Program to 3068 MWt.

5.1.2.4 Pressurized Thermal Shock

All beltline materials are expected to have RT_{PTS} values less than 270°F for plates, forgings, and longitudinal welds, and 300°F for circumferential welds. The pressurized thermal shock (PTS) calculations were performed for IP3 using the latest procedures required by the NRC (Reference 5). Based on the evaluation of PTS, all RT_{PTS} values will remain below the NRC screening criteria values using calculated SPU fluence projections that correspond to a SPU power level of 3216 MW through 27.1 EFPYs (EOL) for IP3 as shown in Table 5.1-3. The change in RT_{PTS} due to the SPU, as compared to the MUR Program to 3068 MWt, is 5°F. This evaluation also determined that the limiting material is relatively close to the PTS screening criteria of 270°F and is expected to exceed this screening criteria at ~36 EFPY.

5.1.2.5 Upper Shelf Energy

All beltline materials have a USE greater than 50 ft-lb through 27.1 EFPY (EOL) as required by the Code of Federal Regulations (CFR) 10CFR50, Appendix G (Reference 6). The 27.1 EFPY (EOL) USE was predicted using the EOL 1/4 thickness (1/4t) SPU fluence projections that correspond to a SPU power level of 3216 MWt. Despite the fact that the vessel fluence projections have increase due to the SPU, as compared to the MUR Program to 3068 MWt, the change in USE decrease is zero. The USE values are presented in Table 5.1-5.

5.1.2.6 Inlet Temperature

RG 1.99, Revision 2 (Reference 7), which is also the basis for 10CFR50.61 (Reference 5), states that "The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement." The temperature range of 525°F to 590°F serves as the basis of the equations and tables that are used in all the RV internal analyses described herein. Therefore, the inlet temperature, which is the temperature to which the reactor vessel is subjected, must be maintained within this range to uphold all existing analyses.

5.1.2.7 Conclusions

The fluence projections used for the SPU, while considering actual power distributions incorporated to date, have increased versus the fluence projections developed for the MUR Program (to 3068 MWt). However, this increase has had minimal affect on the analyses of record for reactor vessel integrity since the PTS and USE remain within the acceptance criteria, the PTS curves had less than l EFPY decrease, the ERG category remains unchanged, and there were only minor withdrawal time changes to the withdrawal schedule. The regulatory criteria continue to be met for the SPU conditions. Therefore, there is no significant effect on RV integrity related to the SPU.

5.1.3 References

1. *ASME Boiler and Pressure Vessel Code, Nuclear Vessels,* American Society of Mechanical Engineers, New York, 1965 Edition through Winter 1965 Addenda.

2. *ASME Boiler and Pressure Vessel Code, Nuclear Power Plant Components,* American Society of Mechanical Engineers, New York (Appendix F and Appendix I Tables), 1974 Edition.

3. Regulatory Guide 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.*

4. ASTM E185-82, *Annual Book of ASTM Standards*, Section 12, Volume 12.02, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

5. 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events, Federal Register*, Volume 60, No. 243, December 19, 1995.

6. 10CFR50, Appendix G, *Fracture Toughness Requirements.*

7. Regulatory Guide 1.99, *Radiation Embrittlement of Reactor Vessel Materials,* Rev. 2, May 1988.

Table 5.1-1

Maximum Range of Stress Intensity and Cumulative Fatigue Usage Factor Results

Location	Maximum Range of Stress Intensity	Cumulative Fatigue Usage Factor
CRDM Housings	[	]a,c,e
Main Closure Closure Head Flange Vessel Flange Closure Studs		
Outlet Nozzles and Supports Nozzle		
Inlet Nozzles and Supports Nozzle		
Vessel Wall Transition		
Core Support Pads		
Bottom Head-to-Shell Juncture		
Instrumentation Tubes		
Head Adapter Plugs		

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.1-2 Recommended Surveillance Capsule Withdrawal Schedule with SPU Fluence Projections				
Capsule	Capsule Location	Lead Factor	Withdrawal EFPY(1)	Fluence (n/cm^2)(2)
T	40°	3.43	1.4	2.63×10^{18}
Y	40°	3.49	3.2	6.92×10^{18}
Z	40°	3.48	5.5	1.04×10^{19}
S	40°	3.46	(3)	(3)
X	4°	1.52	15.5(4)	8.74×10^{18}(4)
V	4°	1.52	EOL(5,6)	(5,6)
W	4°	1.52	EOL(5,6)	(5,6)
U	4°	1.52	EOL(5,6)	. (5,6)

Notes:

1. Effective full power years (EFPYs) from plant startup.
2. Updated during IP3 SPU.
3. IP3 tried to remove capsule S in May of 2001; however, the capsule was not retrievable.
4. Capsule X was removed in May of 2003 at 15.5 EFPY, which is the criteria for the 4th surveillance capsule removal. This capsule has been tested, and the fluence on the capsule has yet been verified.
5. If IP3 is following a withdrawal schedule for EOL (27.1 EFPY), then it is recommended to remove the 5th and standby capsules any time after 16.1 EFPY, but not to exceed 27.1 EFPY (EOL). This would satisfy the ASTM E 185-82 requirement for withdrawal @ EOL, not less than once or greater than twice the peak EOL vessel fluence. The projected fluence on the capsules will be between 9.22×10^{18} n/cm^2 (1 times the peak EOL vessel fluence) and 1.844×10^{19} n/cm^2 (2 times the peak EOL vessel fluence), depending on the exact withdrawal time. The standby capsules should also be withdrawn and placed in storage. Alternative fluence measuring techniques must be applied once standby capsules are removed.
6. If IP3 is following a withdrawal schedule for license extension (45.3 EFPY), then it is recommended to remove the 5th and standby capsules any time after 28.2 EFPY, but not to exceed 45.3 EFPY (EOL). This would satisfy the ASTM E 185-82 requirement for withdrawal @ EOL, not less than once or greater than twice the peak EOL vessel fluence. The projected fluence on the capsules will be between 1.48×10^{19} n/cm^2 (1 times the peak EOL vessel fluence) and 2.96×10^{19} n/cm^2 (2 times the peak EOL vessel fluence), depending on the exact withdrawal time. The standby capsules should also be withdrawn and placed in storage. Alternative fluence measuring techniques must be applied once the standby capsules are removed.

Table 5.1-3

RT_{PTS} Calculations for IP3 Beltline Region Materials at 27.1 EFPY with (3216 MWt) SPU Fluences

Material	Fluence (n/cm^2, E>1.0 MeV)	FF	CF (°F)	ΔRT_{PTS} (1) (°F)	Margin (°F)	$RT_{NDT(U)}$ (2) (°F)	RT_{PTS} (3) (°F)
Intermediate Shell Plate	0.992	0.998	137	136.7	34	5	176
Intermediate Shell Plate	0.992	0.998	152	151.7	34	-4	182
Intermediate Shell Plate	0.992	0.998	136	135.7	34	17	187
Lower Shell Plate	0.992	0.998	128	127.7	34	49	211
Lower Shell Plate	0.992	0.998	150	149.7	34	-5	179
Lower Shell Plate	0.992	0.998	160	159.9	34	74	268
→ Using S/C Data	0.992	0.998	170.9	170.6	17 (4)	74	**262**
Intermediate and Lower Shell Weld Longitudinal Weld Seams (heat 34B009)	0.992	0.998	**224**	223.6	65.5	-56	233
Intermediate to Lower Shell Circumferential weld Seams (heat 13253)	0.992	0.998	**189**	188.6	56	-54	191

Notes:

1. ΔRT_{PTS} = CF * FF
2. Initial RT_{NDT} values are measured values except for the intermediate and lower longitudinal welds.
3. $RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS}$ + Margin (°F)
4. Using credible surveillance data.

Table 5.1-4 ERG Pressure-Temperature Limits	
Applicable RT_{NDT} (ART) Value [1]	**ERG P-T Limit Category**
RT_{NDT} < 200°F	Category I
200°F < RT_{NDT} < 250°F	Category II
250°F < RT_{NDT} < 300°F	Category IIIb

Notes:

1. Longitudinally oriented flaws are applicable only up to 250°F; the circumferentially oriented flaws are applicable up to 300°F.

Table 5.1-5 Predicted 27.1 EFPY USE Calculations for all the Beltline Region Materials with Bounding (3216 MWt) SPU Fluences					
Material	Weight % of Cu	1/4T EOL Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)(1)	Projected EOL USE (ft-lb)
Intermediate Shell Plate B2802-1	0.20	0.550	102	25	77
Intermediate Shell Plate B2802-2	0.22	0.550	97	27	71
Intermediate Shell Plate B2802-3	0.20	0.550	95	25	71
Lower Shell Plate B2803-1	0.19	0.550	72	24	55
Lower Shell Plate B2803-2	0.22	0.550	94	27	69
Lower Shell Plate B2803-3	0.24	0.550	68	18(2)	55(2)
Intermediate and Lower Shell Weld Longitudinal Weld Seams (heat 34B009)	0.19	0.550	112	28	80
Intermediate to Lower Shell Circumferential weld Seams (heat 13253)	0.22	0.550	111	31	77

Notes:

1. Values are deduced from Figure 6.3-1: Regulatory Guide 1.99, Revision 2, predicted decrease in upper shelf energy as a function of copper and fluence.
2. Using surveillance capsule data from previously analyzed capsules T, Y and Z.

5.2 Reactor Pressure Vessel System

Evaluations and analyses were performed to assess the effect on the reactor internals components for a stretch power uprate (SPU) at Indian Point Unit 3 (IP3) to a Nuclear Steam Supply System (NSSS) power level of 3230 MWt (core power of 3216 MWt) for the design life of the plant. The analyses/evaluations were performed with 15 x 15 fuel as described in Section 7 of this document.

5.2.1 Introduction

The Reactor Pressure Vessel (RPV) System consists of the reactor vessel, reactor internals, fuel, and control rod drive mechanisms (CRDMs). The reactor internals support and orient the reactor core fuel assemblies and control rod assemblies, absorb control rod assembly dynamic loads, and transmit these and other loads to the reactor vessel. The reactor vessel internal components support in-core instrumentation and also direct coolant flow through the fuel assemblies (core), to provide adequate cooling flow to the various internals structures. The internals are designed to withstand forces due to structure deadweight, fuel assembly pre-load, control rod assembly dynamic loads, vibratory loads, and earthquake accelerations.

Operating a plant at conditions (power and temperature) other than those considered in the original design requires that the interface between the Reactor Vessel System and the fuel be thoroughly addressed to ensure compatibility and to ensure that the structural integrity of the reactor vessel-internals-fuel system is not adversely affected. In addition, thermal-hydraulic analyses are required to determine plant-specific core-bypass flows, pressure drops, and upper head temperatures to provide input to the loss-of-coolant accident (LOCA) and non-LOCA safety analyses, and to NSSS performance evaluations.

The principal areas affected by changes in system operating conditions are:

- Reactor internals system thermal-hydraulic performance
- Rod control cluster assembly (RCCA) scram performance
- Mechanical system evaluations
- Reactor internals system structural response and integrity
- Bottom-mounted instrumentation (BMI) guide tubes and flux thimbles

The major components and features of the reactor internals system for IP3 are summarized as follows. The lower core support assembly consists of the lower support plate, lower support columns, and lower core plate and core barrel, which support the fuel assemblies on the sides and at the bottom. The radial support system, the head-vessel alignment pins, and special temporary guide studs attached to the vessel guide and align the lower core support assembly during insertion into the reactor vessel. The hold-down spring rests on top of the flange of the lower core support assembly. The upper core support assembly consists of the upper support plate, upper support columns, and upper core plate, and rests on top of the hold-down spring. The guidance and alignment of the upper core support assembly during its insertion are provided by the head-vessel alignment pins, the upper core plate alignment pins in the core barrel assembly, and the special temporary guide studs attached to the vessel. The alignment of the core fuel assemblies is provided through the engagement of the lower core plate fuel pins into the bottom of the fuel assemblies and the upper core plate fuel pins into the top of the fuel assemblies. The vessel upper head compresses the hold-down spring, providing joint preload.

The core barrel, which is part of the lower core support assembly, provides a flow boundary for the reactor coolant. When the primary coolant enters the reactor vessel, it impinges on the side of the core barrel and is directed downward through the annulus formed by the gap between the outside diameter of the core barrel and the inside diameter of the vessel. The flow then enters the lower plenum area between the bottom of the lower support plate and the vessel bottom head and is redirected upward through the core. After passing through the core, the coolant enters the upper core support region and then proceeds radially outward through the reactor vessel outlet nozzles. The perforations in the various components, such as the lower support plate, control and meter the flow through the core.

This section summarizes the work performed to assess the effect on the RPV/internals system of the SPU at IP3.

Input Parameters and Assumptions

The principal input parameters used in the analysis of the reactor internal components and RPV system are the NSSS design parameters developed for the SPU (see Table 2.1-2). For structural analysis evaluations, the NSSS design transients discussed in Section 3 were considered. This evaluation considered a full core of 15 x 15 fuel with intermediate flow mixers (IFMs) and with thimble plugging devices in place.

Operating Parameters

The operating parameters (pressure, temperature, flow, and power level) shown in Table 2.1-2 were used in this evaluation. Also, the design transients discussed in Section 3 were used in this evaluation.

A full core of Westinghouse 15 x 15 fuel with IFMs was used in the analysis.

Description of Analyses and Evaluations

Westinghouse has performed evaluations and analyses to assess the effect of the SPU on the RPV/internals system of IP3. The description of various analyses and evaluations are given in the individual subsections, 5.2.2 through 5.2.5.

Acceptance Criteria

The acceptance criteria are listed in each individual section. However, some of the most important acceptance criteria are grouped together and are as follows:

- The design core bypass flow limit with the thimble-plugging devices in place is 5.5 percent of the total vessel flow rate.
- Hydraulic lift forces on the reactor internals must be limited so that the internals remain seated and stable.
- For the structural and fatigue evaluations of the various reactor internal components, the cumulative fatigue usage factors must be less than 1.0 for the most critically stressed members.

5.2.2 Thermal-Hydraulic System Evaluations

5.2.2.1 System Pressure Losses

The principal Reactor Coolant System (RCS) flow route through the RPV System at IP3 begins at the inlet nozzles. At this point, flow turns downward through the reactor vessel and core barrel annulus. After passing through this downcomer region, the flow enters the lower reactor vessel dome region. This region is occupied by the internals energy absorber structure, lower support columns, BMI columns, and supporting tie plates. From this region, flow passes upward through the lower core plate and into the core region. After passing up through the core, the coolant flows into the upper plenum, turns, and exits the reactor vessel through the four outlet nozzles. The upper plenum region contains support columns and RCCA guide columns.

A key area in evaluation of core performance is the determination of hydraulic behavior of coolant flow within the reactor internals system, that is, vessel pressure drops, core bypass flows, RPV fluid temperatures, hydraulic lift forces, and baffle joint momentum flux. The pressure loss data are necessary inputs to the LOCA and non-LOCA safety analyses and to overall NSSS performance calculations. The hydraulic forces are considered in the assessment of the structural integrity of the reactor internals, core clamping loads generated by the internals holddown spring, and the stresses in the reactor vessel closure studs.

The THRIVE computer code was used to perform this evaluation by solving the mass and energy balances for the reactor internals fluid system. This THRIVE analysis determined the distribution of pressure and flow within the reactor vessel, internals, and the reactor core. Results were obtained with a full core of Westinghouse 15 x 15 fuel with IFM grids, thimble plugs in place, and at RCS conditions, as summarized in Table 2.1-2.

5.2.2.2 Bypass Flow Analysis

Description of Analyses

Bypass flow is the total amount of reactor coolant flow bypassing the core region and was not considered effective in the core heat transfer process. Variations in the size of some of the bypass flow paths, such as gaps at the outlet nozzles and the core cavity, occur during manufacturing or change due to fuel assembly changes. Plant-specific, as-built dimensions were used to demonstrate that the bypass flow limits were not exceeded. Therefore, analyses were performed to estimate core bypass flow values to either show that the design bypass flow limit for the plant will not be exceeded, or to determine a revised design core bypass flow.

The present design core bypass flow limit is 5.5 percent of the total reactor vessel flow with the thimble-plugging devices in place. This evaluation shows that the design value of 5.5 percent was maintained at the RCS conditions described in Table 2.1-2. The principal core bypass flow paths are described in the following paragraphs.

Baffle-Barrel Region

The current reactor vessel internals configuration incorporates downward coolant flow in the region between the core barrel and the baffle plates. In this configuration, a portion of the coolant exits the reactor vessel inlet nozzle and flows downward in the annulus between the vessel and core barrel. The downward flow passes over the thermal shield to the lower plenum, turns, and flows up through the core region. A portion of this flow enters the baffle-barrel region, which consists of vertical baffle plates that follow the periphery of the core. These are joined to the core barrel by horizontal former plates spaced along the elevation of the baffle plates. At IP3, all but the top former plates have flow holes machined in them. Between the top two former levels there are flow holes in the core barrel. Some flow from the vessel and barrel down-comer is diverted through these flow holes, then travels downward through the lower former levels. Most of this baffle/barrel region flow continues down to the top of the lower core plate. There it passes under the baffle plates and into the bottom of the core.

Some fraction of the baffle-barrel plates leaks between the baffle plates and, therefore, is considered as core bypass flow.

Vessel Head Cooling Spray Nozzles

These nozzles provide flow paths between the reactor vessel and core barrel annulus and the fluid volume in the vessel closure head region above the upper support plate. A fraction of the flow that enters the vessel inlet nozzles and into the vessel and barrel downcomer passes through these nozzles and into the vessel closure head region. These flow paths allow circulation of a small fraction of the cold leg coolant into the upper head region of the reactor vessel.

Core Barrel - Reactor Vessel Outlet Nozzle Gap

At IP3, some of the flow that enters the vessel and barrel downcomer leaks through the gaps between the core barrel outlet nozzles and the reactor vessel outlet nozzles and merges with the vessel outlet nozzle flow. Since the lower reactor internals are designed to be removable from the reactor vessel, a small circumferential gap exists at each of the outlet nozzle locations. While the gap is designed to be very small and closes down somewhat at operating conditions due to the differential coefficient of thermal expansion between the reactor internals and the reactor vessel, there is some amount of flow that leaks directly from the vessel inlet/downcomer region and out through these nozzle gaps.

Fuel Assembly - Baffle Plate Cavity Gap

The baffle plates surround the reactor fuel assemblies or core region. The gap between the peripheral fuel assemblies and the baffle plates is defined as the core cavity region. This gap provides the core bypass flow path between the peripheral fuel assemblies and the core baffle plates.

Fuel Assembly Thimble Tubes

Thimble tubes are used as paths for the insertion and removal of control rods, thimble-plugging devices, and various core components such as burnable absorbers. These tubes are physically part of each fuel assembly and flow within them is partially effective in removing core heat. However, such flow was analytically not considered to be effective in heat removal, and was consequentially considered to be part of the core bypass flow.

Bypass Flow Analysis Results

Fuel assembly hydraulic characteristics and system parameters, such as inlet temperature, reactor coolant pressure, and flow were used in conjunction with the THRIVE code to determine the effect of SPU RCS conditions on the total core bypass flow. The calculated core bypass flow value was [ ]^{a,c,e} percent with the thimble-plugging devices in place at the RCS conditions of Table 2.1-2. Therefore, the design core bypass flow value of 5.5 percent with thimble-plugging devices in place , was confirmed to remain bounding.

5.2.2.3 Hydraulic Lift Forces

An evaluation was performed to estimate hydraulic lift forces on the various reactor internal components for the SPU parameters shown in Table 2.1-2. This was done to show that the reactor internals assembly would remain seated and stable for all conditions. The evaluation concluded that the IP3 reactor internals will remain seated and stable for the SPU RCS conditions.

5.2.2.4 Momentum Flux and Fuel Rod Stability

Baffle jetting can be caused by a hydraulically induced instability or vibration of fuel rods, induced by a high velocity jet of water. This jet can be created by high-pressure water being forced through gaps between the baffle plates that surround the core. The baffle-jetting phenomenon could lead to fuel-cladding damage.

At IP3 with SPU conditions and 15 x 15 fuel, the THRIVE evaluations showed that the momentum flux margins were within the design limits and, therefore, baffle jetting is not predicted for IP3 at SPU conditions.

5.2.2.5 Upper Head Fluid Temperatures

The average temperature of the primary coolant fluid that occupies the reactor vessel closure head volume is an important initial condition for certain dynamic LOCA analyses, therefore, it was necessary to determine the upper head temperature for the changes in the RCS conditions. Determination of upper head temperature was derived from the THRIVE evaluations used to assess the core bypass flow. The THRIVE code models the interaction among the different flow paths into and out of the closure head region. Based on this interaction, it calculated the core bypass flow into the head region and the average head fluid temperature based on the different flow path conditions. The IP3 upper head operates at a temperature closer to T_{hot}. For IP3, the upper head region best-estimate mean fluid temperature was calculated to be a maximum of

592.9°F for the RCS conditions provided in Table 2.1-2. The effect of the change in upper head temperature is evaluated in Section 5.10 of this report.

5.2.3 RCCA Scram Performance Evaluation

The RCCAs represent perhaps the most critical interface between the fuel assemblies and the other internal components. It is imperative to show that the SPU RCS conditions will not adversely affect the operation of the RCCAs, either during accident conditions or during normal operation.

The IP3 RCCA drop-time performance assessment involved the following steps:

- Obtained actual plant drop time-to-dashpot entry data at no-flow and full-flow conditions for each RCCA location.

- Developed an analytical model of the plant's driveline configuration and system operating conditions corresponding to those measurements. A driveline was considered to be that subset of components affecting RCCA drop time. These components were the fuel, upper core plate, upper and lower guide tubes, upper support plate, reactor closure head penetration, thermal sleeve, CRDM, rod travel housing, and the RCCA/drive rod assembly. The system operating conditions included temperature, pressure, and flow. The analytical model included values for parameters that describe geometry of driveline components, component mechanical interaction relationships, hydraulic resistances of flow paths, RCCA/drive rod assembly weight, and system operating conditions.

- Used a coded algorithm previously developed by Westinghouse, with the analytical model, to correlate the model to the plant-measured drop times. This algorithm, titled DROP, has been used for this analysis since the original plant design. The DROP algorithm solves Newton's second law of motion. This law states:

$$\Sigma F = (W/g) \times (dV/dt)$$

where:

ΣF	=	Sum of various forces acting on the RCCA/drive rod assembly at any time (t)
W	=	total weight of RCCA/drive rod assembly

g = acceleration due to gravity (32.2 ft/sec^2)

V = assembly velocity (ft/sec)

t = drop time after CRDM latch release of drive rod (sec)

The correlation involved adjustment of specific code input parameters:

— Characterized RCCA drop performance from no-flow (0 percent) through full-flow (100 percent) based on zero-flow and full-flow core average drop-time measurements, and

— Isolated and accounted for the effects of variations in driveline mechanical interference drag force under normal conditions, and variations in driveline flows across the core, based on core-maximum drop time measurements at zero-flow and full-flow, respectively.

- Adjusted the model (that is, DROP input parameter values) to account for the new system operating conditions being considered due to SPU. Also, conservatively accounted for:

  — Component geometric design tolerances

  — Hydraulic performance uncertainties (related to fuel assembly hydraulic resistance, guide tube/RCCA wear, and reactor coolant flow rate)

  — Abnormal environmental conditions (particularly seismic events)

- Assessed the effect of such changes in driveline components and/or primary system operating conditions on the limiting RCCA drop-time characteristics used in the plant accident analyses. These limiting characteristics were the most severe drop time-to-dashpot entry and normalized RCCA drop time position-versus-time relationship estimated based on the tolerances, uncertainties, and abnormal environmental conditions identified above.

The analysis determined the effect of the conditions shown in Table 2.1-2 on the limiting RCCA drop time. The maximum estimated RCCA drop time with the seismic allowance was calculated to be 1.95 seconds to the top of dashpot. This value is less than the current analysis limit of 2.7 seconds. The calculated RCCA drop time value at the SPU power level without a seismic allowance is 1.68 seconds, which is less than the *Technical Specification* limit of 1.8 seconds.

5.2.4 Mechanical System Evaluations

The RCS mechanical response to auxiliary line breaks of a LOCA transient is performed in three steps. First the RCS is analyzed for the effects of loads induced by normal operation, which includes thermal, pressure, and deadweight effects. From this analysis, the mechanical forces acting on the RPV, which would result from release of equilibrium forces at the break locations, are obtained. In the second step, the loop mechanical loads and reactor internals hydraulic forces are simultaneously applied, and the RPV displacements due to the LOCA are calculated. Finally, the structural integrity of the reactor coolant loop (RCL) and component supports to deal with the LOCA are evaluated by applying the calculated reactor vessel displacements to a mathematical model of the RCL (see Section 5.4). Thus, the effects of vessel displacements upon the loop and reactor vessel and internals were evaluated.

5.2.4.1 LOCA and Seismic Loads

The RPV LOCA system mathematical model of IP3 was a three-dimensional (3-D), non-linear, finite element model that represented the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. The model was developed using the WECAN computer code. The WECAN computer code (or predecessor codes) was used for this analysis since the original plant design.

The WECAN computer code, which is used to determine the response of the reactor vessel and its internals, is a general-purpose finite element code. In the finite element approach, the structure is divided into a finite number of members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformation, the element global matrices and arrays are then computed. Finally, the global element matrices and arrays are assembled into the global structural matrices and arrays, and used for dynamic solution of the differential equation of motion for the structure.

To evaluate the effect of changes in RCS conditions on the dynamic response of the RPV System, LOCA analyses were performed to generate core plate motions and the reactor vessel and internals interface loads. The core plate motions were then used to evaluate the structural integrity of the core. Since application of leak-before-break (LBB) methodology has been licensed for the main coolant loop, consideration of breaks in the main coolant loop was not required for structural evaluations (see subsection 5.4.2). The next limiting breaks considered were the branch line breaks. The hydraulic LOCA forces for the breaks listed below were used in the reactor vessel LOCA analysis:

- Accumulator line (cold leg)
- Pressurizer surge line (hot leg)

Following a postulated LOCA, forces were imposed on the reactor vessel and its internals. These forces resulted from the release of the pressurized primary system coolant and, for auxiliary pipe breaks, from the disturbance of the mechanical equilibrium in the piping system prior to the rupture. The release of pressurized coolant resulted in traveling depressurization waves in the primary system. These depressurization waves were characterized by a wavefront with low pressure on one side and high pressure on the other. The wavefront translated and reflected throughout the primary system until the system was completely depressurized. The rapid depressurization resulted in transient hydraulic loads on the mechanical equipment of the system.

The LOCA loads applied to the RPV System consisted of: reactor internal hydraulic loads (vertical and horizontal), and RCL mechanical loads. All the loads were calculated individually and combined in a time-history manner.

The MULTIFLEX computer code calculated the hydraulic transients within the entire primary coolant system. It considered sub-cooled, transition, and two-phase (saturated) blowdown regimes. The MULTIFLEX program uses the method of characteristics to solve the conservation laws, and assumes one-dimensionality of flow and homogeneity of the liquid-vapor mixture.

The MULTIFLEX code considers a coupled fluid-structure interaction by accounting for the deflection of constraining boundaries, which are represented by separate spring-mass oscillator systems. A beam model of the core support barrel was developed from the structural properties of the core barrel. In this model, the cylindrical barrel was vertically divided into various segments and the pressure/wall motions were projected onto the plane parallel to the inlet nozzle on the loop with the postulated auxiliary line pipe break. Horizontally, the barrel was divided into ten segments, with each segment consisting of three separate walls. The spatial pressure variation at each time step was transformed into ten horizontal forces, which acted on the ten mass points of the beam model. Each flexible wall was bounded on either side by a hydraulic flow path. The motion of the flexible walls was determined by solving the global equations of motion for the masses representing the forced vibration of an undamped beam.

The severity of a postulated break in a reactor vessel was related to two factors: the distance from the reactor vessel to the break location and the break opening area. The nature of the reactor vessel decompression following a LOCA, as controlled by the internals structural configuration previously discussed, resulted in larger reactor internal hydraulic forces for pipe breaks in the cold leg than in the hot leg (for breaks of similar area and distance from the RPV). Pipe breaks farther away were less severe because the pressure wave attenuated as it propagated toward the reactor vessel. Therefore, pipe breaks at the reactor vessel inlet nozzle were more severe because of the absence of pressure wave attenuation and the structural configuration of the core. In general, the auxiliary line breaks, like the accumulator line and the pressurizer surge line breaks, were not as severe as the main line breaks, such as RPV inlet nozzle or RCP outlet nozzle break.

The results of reactor vessel displacements and the impact forces calculated at vessel and internals interfaces were used to evaluate the structural integrity of the reactor vessel and its internals.

The core plate motions for both breaks were used in the fuel grid analysis to confirm the structural integrity of the fuel.

Seismic Analyses

The non-linear time-history seismic analyses of the RPV System included the development of the system finite element model and the synthesized time-history accelerations.

Similar to the response during LOCA, the RPV System seismic model included sub-models of the reactor vessel, nozzles, internals, fuel, and CRDMs. The WECAN finite element model described for LOCA was modified to include the fluid-structure interaction in the RPV model for the seismic safe shutdown earthquake (SSE) time history evaluations. The WECAN reactor vessel-internals-fuel assembly model incorporated the effects of fluid-structure interaction in the downcomer region via hydro-dynamic mass matrices between two concentric cylinders (between the core barrel and reactor vessel). The fluid-structure interaction in the seismic analysis was different from that included in the LOCA analysis. In the LOCA analysis, the fluid-structure interaction was included through the MULTIFLEX code; whereas in the seismic analysis, the fluid-structure interaction in the downcomer region (between the core barrel and reactor vessel) was incorporated through the hydro-dynamic mass matrices. The mass matrices with off-diagonal terms were incorporated between nodes on the core barrel and reactor vessel shell.

For a time-history response of the RPV and its internals under seismic excitation, synthesized time-history accelerations were required. The synthesized time-history accelerations for the RPV System analysis were based on the applicable response spectra. The records of a real earthquake, TAFT, were the basis for the synthesized time history accelerations. The spectral characteristics of the synthesized time-history accelerations were similar to the original 'TAFT' earthquake records. The resulting north-south, east-west, and vertical acceleration time-history accelerations were generated for the SSE events.

The results of the system seismic analysis included time-history displacements and impact forces for all the major components. The reactor vessel displacements and the impact forces calculated at vessel and internals interfaces were used to evaluate the structural integrity of the reactor vessel and its internals. The core plate motions were used in the fuel grid analysis to confirm the structural integrity of the fuel.

5.2.4.2 Flow-Induced Vibrations

Flow-induced vibrations (FIVs) of pressurized water reactor (PWR) internals have been studied by Westinghouse for a number of years. The objective of these studies was to show that the structural integrity and reliability of reactor internal components are acceptable for plant operating conditions. These efforts have included in-plant tests, scale-model tests, as well as tests in fabricators' shops and bench tests of components, along with various analytical investigations. The results of these scale-model and in-plant tests indicate that the vibrational behavior of two-, three-, and four-loop plants is essentially similar, and the results obtained from each of the tests complement one another and make possible a better understanding of the FIV phenomena.

Based on the analysis for the IP3 reactor internals, the response due to FIVs was extremely small and well within the allowable levels based on the high-cycle endurance limit for the materials.

5.2.4.3 RCCA Insertion Evaluation

To assess the feasibility of crediting the RCCA insertion during a postulated faulted event, the loads on the guide tubes were calculated. These loads included the dynamic loads derived from the RPV System response, subsection 5.2.3.1, the acoustic loads and the cross flow loads during postulated LOCA events. These loads were combined using the square root sum of the squares (SRSS) method. The postulated LOCA events were the two limiting breaks stated above, namely, the pressurizer surge line break and the accumulator line break.

The evaluations showed that the maximum LOCA loads were within the allowable loads that were established for 15 x 15 type guide tubes to ensure that the RCCA scram time would be acceptable. Consequently, the RCCA insertion for the IP3 plant could be credited following a faulted-condition event. The evaluation also showed that the maximum seismic load is within the allowable load for the 15 x 15 guide tubes. Therefore, control rod insertion is also ensured during a faulted seismic event.

5.2.5 Structural Evaluation of Reactor Internal Components

In addition to supporting the core, a secondary function of the reactor vessel internals assembly is to direct coolant flows within the vessel. While directing primary flow through the core, the internals assembly also establishes secondary flow paths for cooling the upper regions of the reactor vessel and the internals structural components. Some of the parameters influencing the mechanical design of the internals lower assembly are the pressure and temperature differentials across its component parts and the flow rate required to remove heat generated within the structural components due to radiation (for example, gamma heating). The configuration of the internals provides adequate cooling capability. The thermal gradients resulting from gamma heating and core coolant temperature changes are maintained below acceptable limits within and between the various structural components.

Structural evaluations demonstrated that the structural integrity of reactor internal components was not adversely affected either directly by the SPU RCS conditions and transients, or by secondary effects on reactor thermal-hydraulic or structural performance. Heat generated in reactor internal components, along with the various fluid temperature changes, resulted in thermal gradients within and between components. These thermal gradients resulted in thermal stresses and thermal growth, which must be considered in the design and analysis of the various components.

The IP3 reactor internals were designed to meet the intent of Subsection NG of the *ASME Boiler and Pressure Vessel Code*, Section III (Reference 1). A plant-specific stress report on the reactor internals was not required. The structural integrity of the IP3 reactor internals design has been ensured by analyses performed on both generic and plant-specific bases. These analyses were used as the basis for evaluating critical IP3 reactor internal components for SPU RCS conditions and revised design transients.

5.2.5.1 Lower Core Plate

Structural evaluations were performed to demonstrate that the structural integrity of the lower core plate was not adversely affected either by the SPU RCS conditions or by secondary effects on reactor thermal-hydraulic or structural performance. For this lower core plate evaluation, the criteria described in Section III, Subsection NG of the ASME Code (Reference 1) were used.

Primarily because of the higher gamma heating rates associated with the SPU conditions, the lower core plate is one of the most critically stressed components in the reactor internals assembly. The conclusion of these evaluations was that the structural integrity of the lower core plate was maintained. The SPU RCS conditions resulted in acceptable margins of safety and fatigue usage factors for all ligaments under all loading conditions.

5.2.5.2 Upper Core Plate Evaluations

The upper core plate positions the upper ends of the fuel assemblies and the lower ends of the control rod guide tubes, thus serving as the transitioning member for the control rods in entry and retraction from the fuel assemblies. It also controls coolant flow exiting the fuel assemblies and serves as a boundary between the core and the exit plenum. The upper core plate is restrained from vertical movement by the upper support columns, which are attached to the upper support plate assembly. Four equally spaced core plate alignment pins restrain lateral movement.

An evaluation was performed to determine the effect of SPU on the structural integrity of the upper core plate. This evaluation concluded that the upper core plate was structurally adequate for the SPU RCS conditions.

5.2.5.3 Baffle-Barrel Region Components

The IP3 lower internals assembly consists of a core barrel into which baffle plates are installed, supported by interconnecting former plates. A lower core support structure is provided at the bottom of the core barrel and a thermal shield surrounds the core barrel. The components comprising the lower internals assembly are precision-machined. The baffle and former plates are bolted into the core barrel. The reactor vessel internals configuration for IP3 uses downward flow in the barrel-baffle region.

Core Barrel Evaluation

The thermal stresses in the core-active region of the core-barrel shell are primarily due to temperature gradients through the thickness of the core-barrel shell. Evaluations were performed to determine the thermal bending and skin stresses in the core barrel for the SPU RCS conditions. These evaluations indicated that the fatigue usage factor, based on all normal/upset conditions, was well below the allowable value of 1.0. From these conservative results, it was concluded that the core barrel was structurally adequate for the SPU RCS conditions.

Baffle-Barrel Bolt Evaluation

The bolts were evaluated for loads resulting from hydraulic pressure, seismic loads, preload, and thermal conditions. The temperature difference between baffle and barrel produced the dominant loads on the baffle-former bolts. Hydraulic pressure and seismic loads produced the primary stresses, whereas bolt preloading and thermal conditions produced the secondary stresses. The SPU RCS conditions did not affect deadweight or preload forces.

Since these bolts are qualified by test, the evaluation of the revised loads consisted of demonstrating that the loads associated with the SPU RCS conditions were bounded by the loads qualified in the test program. Therefore, it was concluded that the baffle-former and barrel-former bolts were structurally adequate for the SPU RCS conditions.

5.2.5.4 Additional Component Evaluations

A series of assessments were performed on reactor internal components that were not significantly affected by the SPU (and the resulting internal heat generation rates), but were affected by the SPU conditions due to primary loop design transients. These components were:

- Lower support columns
- Instrumentation columns
- Core-barrel-to-lower-support-plate junction
- Thermal shield
- Top hat structure

The results of these assessments, shown in Table 5.2-1, demonstrated that the above listed critical components were structurally adequate for the SPU RCS conditions and the fatigue usage factors were less than 1.0.

5.2.6 BMI Guide Tubes and Flux Thimbles

The BMI guide tubing at IP3 was designed according to the 1970 version of the ASME Code, Section III, Class 1 (Reference 1). The 1970 version of the ASME Code does not include explicit acceptance criteria for the stress evaluation, therefore, Westinghouse performed a quantitative evaluation of the potential effects of the SPU on the IP3 BMI guide tubes based on acceptance criteria from the 1977 version of the ASME Code, Section III, Class 2 rules of NC-3650 (Reference 2). The flux thimbles are qualified as part of the BMI guide tubing. In summary, the use of the 1977 ASME Code criteria is appropriate for this quantitative SPU evaluation, does not change the 1970 ASME design basis for the IP3 BMI guide tubes, and is more conservative than related criteria in ANSI B31.1 (Reference 3).

5.2.6.1 Qualification of BMI Tubing and Flux Thimbles

The evaluation of the IP3 BMI guide tubing and flux thimble due to the SPU conditions was evaluated to ensure that the BMI guide tubes met allowables.

There are three areas that need to be considered for the reconciliation of BMI guide tubing qualification. They are:

- Pressure increase during transients
- Temperature increase during transients and new core inlet temperature from the SPU parameters (see Table 2.1-2)
- Reactor vessel bottom dome displacement during a LOCA

The BMI guide tubing is qualified for 2500 psia and 550°F, so if the service temperature or pressure values are different than the qualified values, the stress values in the guide tubing must be re-evaluated. Also, the reactor vessel displacement at the bottom dome, if different, must be evaluated to determine the stress in the guide tubing.

The evaluation used inputs described in Sections 2 and 3 of this report for temperatures and design transients. Equations 8, 9, 10, 11, and 9-faulted from ASME Section III paragraph NC-3650 (Reference 1) were re-evaluated for the above three changes.

5.2.7 Conclusions

Analyses/evaluations have been performed to assess the effect of changes due to the SPU. The results of these analyses/evaluations demonstrated:

- The use of the design core bypass flow value of 5.5 percent of the total vessel flow rate with thimble-plugging devices in place was confirmed for the SPU RCS conditions.
- The IP3 reactor internals assemblies will remain seated and stable at the SPU RCS conditions.
- The RCCA performance evaluation indicated that the current 2.7-second RCCA drop-time from gripper release of the drive-rod-to-dashpot entry limit was satisfied at the SPU RCS conditions and remained conservatively applicable.
- The baffle plate momentum flux margins of safety due to SPU RCS conditions were relatively unchanged from present conditions for mechanical design flow, and remained acceptable.

- The evaluations indicated that the SPU RCS conditions will not adversely affect the response of reactor internals systems and components due to seismic/LOCA excitations and FIVs.

- The evaluations of the critical reactor internal components indicated that the structural integrity of the reactor internals was maintained at the SPU RCS conditions. Limiting CUFs were all shown to be less than 1.0.

- The stresses in the BMI guide tubing were within the allowables and meet the requirements of ASME Section III, paragraph NC-3650 (Reference 1). The new stress values are compared with their allowables in Table 5.2-2.

5.2.8 References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1968 Edition with Winter 1970 Addenda, The American Society of Mechanical Engineers, New York, NY.

2. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1977 Edition with Winter 1977 Addenda, The American Society of Mechanical Engineers, New York, NY.

3. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1.0 – 1967*, 1967 Edition, The American Society of Mechanical Engineers, New York, NY.

Table 5.2-1 IP3 – SPU Summary of Critical Reactor Internal Components Fatigue Usage Factors	
Component	**Cumulative Fatigue Usage Factor (U)**
Lower Core Plate	[ ]a,c,e
Upper Core Plate	
Lower Support Columns	
Instrumentation Columns	
Core-Barrel-to-Lower-Support-Plate Junction	
Thermal Shield	
Top Hat Structure	

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.2-2 Maximum Stresses for BMI Tubes		
Equation No.	Stress (psi)	Allowable Stress (psi)
8	[	]a,c,e
9		
10		
11		
9-Faulted		

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.3 Control Rod Drive Mechanisms

5.3.1 Introduction

This section addresses the ASME Code of Record structural considerations for the pressure boundary components of the Westinghouse full-length L-106 control rod drive mechanisms (CRDMs). The CRDMs were evaluated for the Indian Point Unit 3 (IP3) stretch power uprate (SPU) conditions.

5.3.2 Input Parameters and Assumptions

The Model L-106 CRDMs were originally designed and analyzed to meet the ASME Code 1965 Edition through the Summer 1966 Addenda or later (Reference 1). The Nuclear Steam Supply System (NSSS) design parameters for the IP3 SPU are provided in Table 2.1-2 of this report and the NSSS design transients are discussed in Section 3.1, also of this report. The seismic loading has not been changed for the IP3 SPU.

The IP3 CRDMs operate with a T_{hot} upper head condition, defined by the vessel outlet reactor coolant temperature of the SPU parameters, and must be analyzed for the NSSS design transients defined for the hot leg. The differences associated with the uprating requirements are discussed in subsection 5.3.3 of this report.

5.3.3 Description of Analysis

5.3.3.1 Operating Pressure and Temperature

The Reactor Coolant System (RCS) temperature and pressure values were compared to the current design analysis for the CRDMs. There are no changes from the current reactor coolant pressure of 2250 psia for any of the uprating cases from the SPU parameters for IP3. The hot leg temperature (T_{hot}) defined by the vessel outlet temperature on the parameters for the IP3 SPU is a maximum of 603.0°F, which is less than the 650.0°F temperature used in the original analysis of record. Since none of the temperatures exceeds the previously analyzed temperature, and the pressure does not change, the SPU parameters are bounded by the current analyses of record.

Table 5.3-1 summarizes the hot leg parameters. From Table 5.3-1, the SPU conditions provide an RCS T_{hot} of 580.3° to 603.0°F. Therefore, the original 650.0°F range bounds the range of T_{hot} for the SPU.

5.3.3.2 Transient Discussion

The only hot leg transient that has been modified to become more severe for the IP3 SPU is the loss-of-flow transient. For the loss-of-flow transient, the change in T_{hot} temperature for the high-temperature operating condition becomes -123°F. For the original design transient, the controlling temperature change for this transient was -92.6°F. Evaluations were performed to address the T_{hot} and pressure variations for this loss-of-flow transient. Also, more severe pressure variations for IP3 SPU occur for step-load rejection and reactor trip from full power. These were also evaluated as part of SPU.

Concerning the hydrotest at 2500 psi, the IP3 SPU implies a number of transient occurrences of 200 instead of 5, as previously required by the original equipment specification. These 200 occurrences of hydrotest were evaluated as part of the SPU and shown to be acceptable.

The results of these evaluations are addressed in subsection 5.3.5 for the IP3 SPU.

5.3.4 Acceptance Criteria

The acceptance criteria for the ASME Code structural analysis of the CRDM pressure boundary are that the analyzed stresses do not exceed the stress allowables of the ASME Code and that the cumulative usage factors from the Code fatigue analysis remain less than 1.0.

For the IP3 SPU, the stresses and the cumulative usage factors (CUFs) calculated for the CRDMs for the IP3 SPU remain acceptable.

5.3.5 Results

A summary of the results of the evaluation performed for the IP3 SPU is presented in Tables 5.3-2 and 5.3-3. The highest recalculated stresses, as compared to the associated allowables, are presented in Table 5.3-2 for the upper, middle, and lower joints of the CRDM pressure boundary. The CUFs that were recalculated for the IP3 SPU are given in Table 5.3-3. It is noted that the highest CUF, [ ]^{a,c} was calculated for the IP3 SPU at the upper joint canopy. For the original design calculation, a higher fatigue usage factor [ ]^{a,c} was calculated at the upper joint canopy in a conservative manner where the applied transients were grouped for analysis and the allowable number of cycles considered for each group was based on the most severe transient in the group.

5.3.6 Conclusions

The IP3 SPU Performance Capability Working Group (PCWG) parameters and NSSS design transients have been shown to be bounded by the parameters and transients considered for the original design analysis. The CRDMs are acceptable from a structural standpoint. The CRDM pressure boundary parts still satisfy the ASME Code of record. Therefore, the evaluation results for the SPU are consistent with, and continue to comply with, the current licensing basis/acceptance requirements for IP3.

References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition through Summer 1966 Addenda, The American Society of Mechanical Engineers, New York, NY.

Table 5.3-1 PCWG Conditions Used to Bracket All Operating Conditions for IP3 SPU				
	3068-MWt Analysis		3216-MWt SPU	
Parameter	High T_{avg}	Low T_{avg}	High T_{avg}	Low T_{avg}
T_{hot}	600.8°F	600.8°F	603.0°F	580.3°F

Table 5.3-2 Highest Stresses, Compared to Allowables, for CRDM Joints, Applicable for IP3 SPU		
	Normal and Upset Condition Stresses (psi)	
*CRDM Joint and Component	Value Applicable for the SPU	Allowable Value
Upper Joint Canopy	[ ]a,c	48,300
Middle Joint Canopy		45,900
Lower Joint Canopy*		45,900
Capped Latch Housing (CLH) Short Cap		52,200

Bracketed [ ]^{a,c} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

* The 3 S_m allowable (45,900 psi) is exceeded by [ ]^{a,c} psi. This is insignificant and therefore considered acceptable.

Table 5.3-3 CUFs for CRDM Joints, Applicable for IP3 SPU		
CRDM Joint and Component	Cumulative Usage Factor	
	Value Applicable for the SPU	Allowable Value
Upper Joint Canopy	[ ]a,c	1.00
Middle Joint Canopy		1.00
Lower Joint Canopy		1.00
CLH Short Cap		1.00

Bracketed [ ]a,c information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.4 Reactor Coolant Loop Piping and Supports

5.4.1 RCL Piping

5.4.1.1 Introduction

The parameters associated with the Indian Point Unit 3 (IP3) stretch power uprate (SPU) were evaluated and analyzed to determine the effects on the analysis of WCAP-8228, Revision 1, (Reference 1) of the reactor coolant loop (RCL) analysis for the following components:

- RCL piping stresses and displacements
- Primary equipment nozzle loads
- Pressurizer surge line piping stresses and displacements including the effects of thermal stratification
- RCL branch nozzle loads
- Class 1 and 2 auxiliary piping systems

5.4.1.2 Inputs

The following four basic sets of input parameters were considered in the evaluation:

- Nuclear Steam Supply System (NSSS) design parameters (Table 2.1-2 of Section 2)
- NSSS design transients (Section 3 of this report)
- Loss-of-coolant accident (LOCA) hydraulic forcing functions loads (Section 6.7 of this document) and associated reactor pressure vessel (RPV) motions (Section 5.2 of this document)
- Secondary side pressure effects (Table 2.1-2 of Section 2)

The parameters associated with the SPU were reviewed to determine the effects on the existing RCL piping and the subsequent effects on the RCL branch nozzles and the Class 1 and 2 auxiliary lines attached to the RCL. The conclusions of this review are summarized later in subsection 5.4.1.6.

NSSS Design Parameters

The NSSS design parameters (see Table 2.1-2 of this report) were used in the thermal analysis of the RCL and the pressurizer surge line. The RCL was evaluated for two temperature conditions—one for the lower-bound temperature condition (Cases 1 and 2), and the second for the upper-bound temperature condition (Cases 3 and 4) as identified in Table 2.1-2.

NSSS Design Transients

The effect on design transients due to the changes in full-power operating temperatures for the SPU is addressed in Section 3 of this report. WCAP-8228 (Reference 1) specifies the design criteria for the RCL piping as *USAS B31.1 Power Piping Code*, 1967 Edition (Reference 2), which does not require fatigue analysis for the RCL.

For the pressurizer surge line, the effect of the design transients is controlled by the ΔT between the pressurizer temperature and the hot leg temperature. It has been shown that the temperatures and the design transients affected by the SPU have an insignificant effect on the pressurizer surge line analysis, including the effects of thermal stratification. However, this effect is also evaluated.

LOCA Hydraulic Forcing Functions Loads and Associated RPV Motions

The effect on the LOCA hydraulic forcing functions (HFFs) due to the SPU is addressed in Section 6.7 of this report. Leak-before-break (LBB) is applicable for the RCL main loop piping (see subsection 5.4.2). Based on the application of LBB, the RCL was evaluated for LOCA using HFFs generated for the SPU, based on breaks at the 14-inch surge line nozzle and at the 14-inch residual heat removal (RHR) line nozzle on the hot leg, and at the 10-inch accumulator line nozzle on the cold leg. RPV motions corresponding to the surge line break, RHR line break, and accumulator line break were also included.

Secondary Side Pressure Effects

The RCL was evaluated for secondary side breaks at the main steam line and feedwater line terminal end nozzle locations at the steam generator. The feedwater line break (FWLB) and the main steam line break (MSLB) evaluation for the SPU is performed based on the secondary side pressure in the NSSS design parameters (Table 2.1-2 of Section 2).

5.4.1.3 Analysis Methods

The system analysis of the RCL piping was performed using the methods in WCAP-8228 (Reference 1), using the computer program WESTDYN for deadweight, thermal expansion, LOCA and pipe break cases. The seismic analysis was performed using the WECAN computer code.

5.4.1.4 Acceptance Criteria

The acceptance criteria for the IP3 RCL Piping System as indicated in the *Indian Point Nuclear Generating Unit No. 3 Updated Final Safety Analysis Report (UFSAR)*, Table 1.4-1 and Section 10.2.1 (Reference 3) are based upon the *ANSI Code for Pressure Piping, Power Piping USAS B31.1*, 1955 Edition (Reference 4). For the stress analysis evaluation performed for the SPU, the acceptance criteria are based on the requirements established in *ANSI Code for Pressure Piping, Power Piping USAS B31.1*, 1967 (Reference 2), as specified in WCAP-8228 (Reference 1) in which the steam generator snubber elimination calculation was performed.

The acceptance criteria for the pressurizer surge line thermal stratification analysis are those in the *American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel (B&PV) Code* Section III, Subsection NB, 1986 Edition (Reference 5), as specified in WCAP-12937 (Reference 6).

The piping stress criteria for the RCL piping are the code-allowable stress values presented in Tables 5.4-1, 5.4-2, and 5.4-3.

5.4.1.5 Analysis and Results

The deadweight analysis for the SPU considered the weight of the RCL piping and the primary equipment water weight. Since there are no changes in the weight of the system, the deadweight analysis is not revised for the SPU. The results in the analysis of WCAP-8228 (Reference 1) remain applicable for the deadweight analysis.

The thermal analysis considered the range of operating temperatures for 100-percent power as defined by the SPU NSSS design parameters identified in Table 2.1-2 of this report. The temperatures used in the thermal analysis in WCAP-8228 (Reference 1) are shown to remain applicable to the corresponding temperature ranges for the SPU. Therefore, the thermal analysis results in WCAP-8228 (Reference 1) are shown to remain applicable for the SPU.

The seismic analysis performed in WCAP-8228 (Reference 1) has been shown to remain applicable for the SPU.

The LOCA analysis for the RCL is performed using the time-history hydraulic forces distributed throughout the RCL system, including the effects of the SPU-associated RPV motion. The analysis is performed for the breaks at the auxiliary nozzles for the 14-inch RHR line on the hot leg, the 14-inch surge line nozzle on the hot leg, and the 10-inch accumulator line on the cold leg. IP3 has been licensed for LBB on the main RCL piping. The LOCA analysis considered multiple cases based on the various primary equipment support activity cases and accounted for the range of operating temperatures as defined by the SPU NSSS design parameters.

Secondary side breaks at the main steam line and feedwater line terminal end nozzle locations at the steam generator are included in the analyses. The feedwater nozzle break analysis conservatively performed in WCAP-8228 (Reference 1) is shown to remain applicable for the SPU. The main steamline break (MSLB) analysis is performed using the secondary side pressure from the SPU NSSS design parameters.

The maximum RCL piping stress results for the RCL piping and the corresponding code-allowable stress values are presented in Tables 5.4-1, 5.4-2, and 5.4-3. The stresses were combined in accordance with the methods specified in the criteria in subsection 5.4.1.4. As per WCAP-8228 (Reference 1), the following stresses from the load combinations are required for the normal, upset, faulted, and thermal expansion conditions:

- Normal condition = pressure + deadweight
- Upset condition = pressure + deadweight +OBE
- Faulted 1 condition = pressure + deadweight + DBE
- Faulted 2 condition = pressure + deadweight + DBE + pipe rupture
- Thermal expansion condition = normal thermal

As can be seen in Tables 5.4-1 through 5.4-3, the RCL piping stresses are within the allowable limits and meet the acceptance criteria (Reference 2) and are acceptable for the SPU.

The primary equipment nozzle loads were compared to the allowables and to previously qualified nozzle loads evaluated for WCAP-8228 (Reference 1) as applicable and are shown to meet the criteria and to be acceptable for the SPU and have no adverse effect on the results.

The SPU effect on the RCL piping displacements at the RCL branch nozzles and corresponding Class 1 and Class 2 auxiliary piping systems was evaluated. These evaluations considered the SPU parameters, SPU LOCA HFFs, and the NSSS fluid system performance evaluation in Section 4 of this report. These evaluations included the Reactor Coolant System (RCS), Primary Sampling System (PSS), Chemical and Volume Control System (CVCS), Residual Heat Removal System (RHRS), Safety Injection System (SIS), Component Cooling Water System

(CCWS), and the Containment Spray System (CSS). The SPU effect on RCL piping displacements at branch nozzles had a negligible effect on the RCL branch nozzle loads and on the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL.

Based on the discussion in subsection 5.4.1.2 for the evaluation of the NSSS design parameters and the NSSS design transients for the SPU, the current design basis pressurizer surge line analysis results including the effects of thermal stratification in WCAP-12937 (Reference 6), are applicable and meet the acceptance criteria for the SPU. Therefore, the SPU will have no adverse effect on either the thermal stratification or the fatigue analysis for the pressurizer surge line, and the limiting transients and the pressurizer surge line evaluation in WCAP-12937 (Reference 6) remain valid.

5.4.1.6 Conclusions

The RCL piping stress results in Tables 5.4-1, 5.4-2, and 5.4-3 demonstrate that the RCL piping stresses meet the required stress criteria under the SPU.

The primary equipment nozzle loads are shown to meet the criteria and are acceptable for the SPU and have no adverse effect on the results.

RCL piping displacements at branch nozzles due to the SPU has no adverse effect on either the RCL branch nozzle loads or the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL. Therefore, these nozzles and piping systems meet the acceptance criteria and are acceptable.

Additionally, the current design basis analysis results for the pressurizer surge line as documented in WCAP-12937 (Reference 6), including the effects of thermal stratification, are still applicable, acceptable, and meet the acceptance criteria and remain valid for the SPU.

Therefore, based on the evaluations performed on the RCL piping system for the SPU, the RCL piping system is adequate and acceptable, and meets all the acceptance criteria.

5.4.2 Application of LBB Methodology

The current structural design basis of IP3 includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. This section describes the analyses and evaluations performed to demonstrate that the elimination of these breaks continues to be justified at the operating conditions associated with the IP3 SPU.

5.4.2.1 Introduction

LBB analyses were performed for the IP3 primary loop piping in 1984 and 1997. The results of the 1984 LBB analyses were documented in *Fracture Proof Design Corporation Report 80-121*, Revision 0 (Reference 7), and approved by the NRC (Reference 8). Analyses performed in 1997 to support the Steam Generator Snubbers Deactivation Program and the results of the LBB analyses were documented in Appendix A of the WCAP-8228 (Reference 1).

To demonstrate the elimination of RCS primary loop pipe breaks, the following objectives had to be achieved:

- Demonstrate that margin exists between the "critical" crack size and a postulated crack that yields a detectable leak rate.
- Demonstrate that there is sufficient margin between the leakage through a postulated crack and the leak detection capability.
- Demonstrate margin on the applied load.
- Demonstrate that fatigue crack growth is negligible.

These objectives were met and are documented in the *Fracture Proof Design Corporation Report* (Reference 7) and Appendix A of the WCAP-8228 (Reference 1).

To support the IP3 SPU, the current LBB analyses were updated to address SPU conditions. The SPU evaluation and results are addressed below.

5.4.2.2 Input Parameters and Assumptions

The loadings, operating pressure, and temperature parameters for the SPU were used in the evaluation.

The parameters, which are important in the evaluation, are the piping forces, moments, normal operating temperature, and normal operating pressure. These parameters were used in the evaluation. For normal operating temperature and normal operating pressure at the SPU conditions, see Section 2 of this report.

5.4.2.3 Description of Analyses and Evaluations

The recommendations and criteria proposed for LBB evaluation in *Standard Review Plan* (SRP) 3.6.3 (Reference 9) are used in this evaluation. The primary loop piping deadweight, normal thermal expansion, safe shutdown earthquake (SSE), and pressure loads due to the SPU have been used. The normal operating temperature and pressure due to the SPU conditions were used in the evaluation. The evaluation showed that all the LBB-recommended margins were satisfied for the SPU conditions. The margins from SRP 3.6.3 (Reference 9) are also described below.

5.4.2.4 Acceptance Criteria and Results

The LBB acceptance criteria is based on the SRP 3.6.3 (Reference 9). The recommended margins are as follows:

- Margin of 10 on leak rate
- Margin of 2 on flaw size
- Margin on loads of 1 (using faulted load combinations by absolute summation method)

The evaluation results showed the following at all the critical locations:

Leak Rate – There is a margin of 10 between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gpm.

Flaw Size – There is a margin of 2 or more between the critical flaw and the flaw having a leak rate of 10 gpm (the leakage flaw).

Loads – There is a margin of 1 on loads.

The evaluation results show that the LBB conclusions provided in the *Fracture Proof Design Corporation Report* (Reference 7) and Appendix A of the WCAP-8228 (Reference 1) for IP3 remain unchanged for SPU conditions.

5.4.2.5 Conclusions

The LBB acceptance criteria are satisfied for the IP3 primary loop piping at the SPU conditions. All the recommended margins are satisfied and the conclusions shown in *Fracture Proof Design Corporation Report* (Reference 7) and Appendix A of the WCAP-8228 (Reference 1) remain valid. It is, therefore, concluded that the dynamic effects of RCS primary loop pipe breaks need not be considered in the structural design basis of IP3 at the SPU conditions.

5.4.3 RCS Equipment Supports

5.4.3.1 Introduction

This report documents the acceptability of the equipment supports for the SPU conditions. The parameters associated with the SPU were reviewed to determine the effects of the SPU conditions on the existing design basis analysis for the RCS equipment supports (RCSES). The following loads were considered in the analysis:

- Piping loads on RCSES
  - Deadweight
  - Thermal
  - Pressure
  - Operating basis earthquake (OBE) and design basis earthquake (DBE)
  - Pipe break (main steam and feedwater)
  - LOCA (pressurizer surge line, RHR, 45-degree, and 90-degree accumulator)
- Loads due to attachments to RCSES
  - Pipe supports
  - Whip restraints
- Pipe whip and jet impingement loads on RCSES
  - From 10-inch lines and larger

Note that per subsection 5.4.1.5, "The SPU effect on RCL piping displacements at branch nozzles had a negligible effect on the RCL branch nozzle loads and on the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL." Therefore, support reconciliations are not required.

5.4.3.2 Inputs

The following sets of inputs were used in the evaluation:

- RCSES as-built drawings and embedment allowables
- Support pipe whip and jet impingement loads
- Support attachment locations and loads
- RCL piping loads
- Reactor vessel loads

The IP3 RCL was re-analyzed for postulated LOCA to incorporate the SPU power uprate conditions. The RCL piping analysis calculated revised loads from the piping to the steam generator and RCP supports. The reactor vessel analysis calculated revised loads for the reactor vessel support reconciliation.

5.4.3.3 Analysis Methods

The equipment supports were analyzed by developing detailed structural computer models of the steam generator and reactor coolant pump (RCP) support frames, then loading the frame with the various loads determined in the RCL piping analysis. Additional loads corresponding to auxiliary line pipe whip, pipe whip restraint attachments, and pipe supports were also applied to the support frames. GTSTRUDL Version 26 NT was used for the structural modeling. The GTSTRUDL code evaluation option was used to qualify the standard AISC shapes used in the support frames per the acceptance criteria discussed in subsection 5.4.3.4. For the non-standard members, stresses were obtained from GTSTRUDL and calculations were then performed to satisfy the code interaction equations. The support frame embedment reactions calculated within GTSTRUDL were compared with the allowable embedment loads. Miscellaneous members such as tie rods were qualified with the use of separate calculations.

The reactor vessel supports were qualified by comparing the maximum LOCA faulted loads on the supports with the allowable loads on the support shoe developed per scale model tests. The LOCA loads on the reactor vessel support envelope loads due to the other pipe breaks, MSLB, and feedwater break, since the secondary side breaks do not cause the large primary side pressure waves associated with a primary side break.

The normal, seismic, feedwater break, and mainsteam break loads on the support structures were not affected by the SPU, therefore, the SPU support evaluations focused only on the faulted conditions containing the postulated LOCA cases. The normal, upset, and faulted RCS equipment support evaluations for the mainsteam and feedwater breaks previously performed for the steam generator snubber elimination analyses completed in 1997 were not affected by the SPU and, therefore, were not redone.

The loads considered in the support evaluations are as follows:

- Deadweight — Loads due to deadweight of equipment, attached piping, insulation, and contained fluids
- Thermal — Load on the supports due to constrained thermal expansion of the RCL
- Pressure — Loads on the supports due to system pressure of the RCL

- OBE — Seismic loads due to the OBE
- DBE — Seismic loads due to the DBE
- Main steamline — Loads due to a break at the steam generator main steamline nozzle (MSLB)
- Feedwater line — Loads due to a break at the steam generator main feedwater line nozzle (FLB)
- LOCA — Loads due to a break in any one of several RCL nozzles, that is, surge line nozzle, RHR line nozzle, or accumulator line nozzle

The LOCA loads on the support structures were combined with the DBE loads by the square root of the sum of the squares (SRSS) method, then added to the deadweight, pressure, and thermal loads to form the faulted loading combinations considered in the GTSTRUDL analyses.

Normal, seismic, and pipe break loads were combined based on the probability of occurrence and evaluated to stress levels that were increased for low probability events. The load combinations identified in Table 5.4-4 are based on Table 16.1-2 of the UFSAR (Reference 3).

5.4.3.4 Acceptance Criteria

The acceptance criteria for the IP3 RCSES are based upon Table 16.1-2 in the UFSAR (Reference 3), in combination with the criteria discussed below.

Steam Generator and RCP Frames

Load Cases 1, 2, and 3 were previously qualified as part of the Steam Generator Snubber Elimination Program and are not impacted as part of the SPU. Load case 4 is enveloped by load Case 5.

For load Cases 4 and 5 the criteria is that "Deflections and stresses of supports limited to maintain supported equipment within their stress limits." This correlates to limiting the deflection of the supports such that additional stresses do not occur in the supported piping/equipment. Acceptable means of satisfying the above criteria are to use the faulted increase factors provided in Appendix F of the 1974 *Boiler & Pressure Vessel* Section III Code for Supports, that is, F-1370(a) and F-1370(c) (Reference 10). These rules state that the increase factor for faulted-condition loads can be increased above the Level A (AISC allowables) by:

- Increase Factor (IF) = minimum 1.2 x (S_y / F_t) and 0.7 x (S_u / F_t)
  Since F_t = 0.6 S_y for the frame members being considered,

- IF = minimum 2 and (0.7 x S_u) / (0.6 x S_y)

- Section F-1370(c) states that loads shall not exceed 2/3 of the critical buckling load

Steam Generator and RCP Tie Rods

The steam generator and RCP tie rods are tension members. As such, the allowable loads were based on the lesser of the turnbuckle rated load multiplied times 1.33, the tensile stress in the tie rods, and the bearing stress under the nuts. The turnbuckle rated load (which is 20 percent of the turnbuckle ultimate capacity) multiplied times 1.33 is the controlling allowable load for the tie rods.

Concrete Embedments

The calculated loads on the embedments were shown to be enveloped by the embedment allowable loads (see Table 5.4-5) from the original design.

RCP and Steam Generator Holddown Bolts

Each pump foot is restrained by a 4-inch diameter A490 bolt. The allowable tension stress, allowable shear stress and shear tension interaction defined in ASME Code Case 1644-6 (Reference 11) and Appendix F (Reference 10) was used to evaluate the A490 bolts since the AISC Sixth Edition (Reference 12) does not specify allowable stresses for A490 bolts.

The steam generator feet are connected to a pad with a 2.75-inch diameter ASTM A540 Class 1 pin and four 3/4-inch diameter A490 bolts. The pad is then connected the steam generator frame columns with four 2-inch diameter ASTM A540 Class 2 bolts.

This connection was evaluated by calculations to satisfy the allowable tension stresses and the allowable shear stresses per Code Case 1644 and Appendix F in the bolts and pins.

RPV Supports

The reactor vessel support evaluations were based on WCAP-9117 (Reference 13). This report documents scale model tests that were used to determine the reactor vessel support shoe horizontal capacity. The support shoe governs the overall support horizontal capacity.

5.4.3.5 Analysis and Results

The loads on the steam generator, RCP, and RPV supports meet the acceptance criteria provided in subsection 5.4.3.4 of this report.

As noted previously in subsections 5.4.1.5 and 5.4.3.1, the effect on RCL piping displacements at branch nozzles due to the SPU has no subsequent effect on either the RCL branch nozzle loads or the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL (as applicable). Therefore, the supports for the auxiliary piping systems are not affected by the SPU. The previous analyses for these supports apply for the SPU.

A summary of the results is provided in Table 5.4-6.

5.4.4 References

1. WCAP-8228, Vol. 1, *Structural Evaluation of Reactor Coolant Loop/Support System For Indian Point Nuclear Generating Station Unit No. 3*, Rev. 1, April 1997

2. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1.0 – 1967*, 1967 Edition, The American Society of Mechanical Engineers, New York, NY.

3. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

4. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1.0 – 1955*, 1955 Edition, The American Society of Mechanical Engineers, New York, NY.

5. *American Society of Mechanical Engineers Boiler & Pressure Vessel Code*, Section III, Subsection NB, 1986 Edition, The American Society of Mechanical Engineers, New York, NY.

6. WCAP-12937, *Structural Evaluation of Indian Point Units 2 and 3 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification*, May 1991.

7. *Fracture Proof Design Corporation Report 80-121, Summary of the Tearing Stability Analysis of the Indian Point 3 Primary Coolant System*, Rev. 0, May 4 1984.

8. NRC Docket # 50-286, Letter from Steven A. Varga PWR Project Directorate No. 3, Division of PWR Licensing-A of the NRC to Mr. John C. Brons, Senior Vice President Power Authority of the State of New York, March 10, 1986.

9. *Standard Review Plan*, Public Comment Solicited, 3.6.3, "Leak-Before-Break Evaluation Procedures," Federal Register/Vol. 52, No. 167/Friday, August 28, 1987/Notices, pp. 32626-32633.

10. *ASME Boiler & Pressure Vessel Code,* Section III, Appendix F, 1974 Edition, The American Society of Mechanical Engineers, New York, NY.

11. *ASME Boiler & Pressure Vessel Code*, Code Case 1644-6, The American Society of Mechanical Engineers, New York, NY.

12. *American Institute of Steel Construction (AISC) Specification for Design, Fabrication & Erection of Structural Steel for Buildings*, 1963 Edition.

13. WCAP-9117, *Analysis of Reactor Coolant System for Postulated Loss-of-Coolant Accident: Indian Point 3 Nuclear Power Plant*, June 1977.

Table 5.4-1

RCL Piping Stress Analysis Summary for Loops 31/34 – SPU

Stress Combination	Hot Leg Maximum ksi	Hot Leg Allowable ksi	Crossover Leg Maximum ksi	Crossover Leg Allowable ksi	Cold Leg Maximum ksi	Cold Leg Allowable ksi
Normal Condition (pressure + deadweight)	6.985 (1) 5.296 (2)	17.050 (1) 14.950 (2)	6.821 (1) 5.403 (2)	17.050 (1) 14.950 (2)	6.850 (1) 5.429 (2)	17.050 (1) 14.950 (2)
Allowable Stress Limit (5)	(1.0 S)		(1.0 S)		(1.0 S)	
Upset Condition (pressure+deadweight + OBE)	13.137 (1)	20.460 (1)	10.755 (1)	20.460 (1)	9.693 (1)	20.460 (1)
Allowable Stress Limit (5)	(1.2 S)		(1.2 S)		(1.2 S)	
Faulted 1 Condition (pressure+deadweight+DBE)	13.137 (1)	20.460 (1)	10.755 (1)	20.460 (1)	9.693 (1)	20.460 (1)
Allowable Stress Limit (5)	(1.2 S)		(1.2 S)		(1.2 S)	
Thermal Expansion Condition (normal thermal)	17.350 (1)	27.700 (1)	6.240 (1)	27.700 (1)	3.850 (1)	27.700 (1)
Allowable Stress Limit (5)	$(1.25 \times S_c + 0.25 \times S_h)$		$(1.25 \times S_c + 0.25 \times S_h)$		$(1.25 \times S_c + 0.25 \times S_h)$	

Note:

1. These are the maximum stresses and allowable corresponding to piping material.
2. These are the maximum stresses and allowable corresponding to elbow material.
3. S = Allowable stress in material at the operating temperature.
4. S_c = Allowable Stress of material at ambient temperature (70°F).
5. S_h = Allowable Stress of material at maximum hot temperature (650°F).

Per References 1 and 2.

Table 5.4-2 RCL Piping Stress Analysis Summary for Loops 32/33 – SPU						
Stress Combination	Hot Leg		Crossover Leg		Cold Leg	
	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi
Normal Condition (pressure + deadweight)	6.985 (1) 5.296 (2)	17.050 (1) 14.950 (2)	6.821 (1) 5.403 (2)	17.050 (1) 14.950 (2)	6.750 (1) 5.329 (2)	17.050 (1) 14.950 (2)
Allowable Stress Limit (5)	(1.0 S)		(1.0 S)		(1.0 S)	
Upset Condition (pressure+deadweight+OBE)	12.864 (1)	20.460 (1)	10.458 (1)	20.460 (1)	9.300 (1)	20.460 (1)
Allowable Stress Limit (5)	(1.2 S)		(1.2 S)		(1.2 S)	
Faulted 1 Condition (pressure+deadweight+DBE)	12.864 (1)	20.460 (1)	10.458 (1)	20.460 (1)	9.300 (1)	20.460 (1)
Allowable Stress Limit (5)	(1.2 S)		(1.2 S)		(1.2 S)	
Thermal Expansion Condition (normal thermal)	17.150	27.700	7.150	27.700	7.350	27.700
Allowable Stress Limit (5)	(1.25 x S_c + 0.25 x S_h)		(1.25 x S_c + 0.25 x S_h)		(1.25 x S_c + 0.25 x S_h)	

Note:

1. These are the maximum stresses and allowable corresponding to piping material
2. These are the maximum stresses and allowable corresponding to elbow material.
3. S = Allowable stress in material at the operating temperature.
4. S_c = Allowable Stress of material at ambient temperature (70° F).
5. S_h = Allowable Stress of material at maximum hot temperature (650° F).
   Per References 1 and 2.

Table 5.4-3 Faulted 2 Condition Maximum Piping Stress Pressure + Deadweight + DBE + Pipe Rupture - Combination Case											
	Piping Stress (ksi)						Stress Ratio				
	SI	S_Y	S_a Max.	S_a Min.	S_τ	S_H	SI/S_Y	S_a Max. / S_Y	S_a Min. / S_Y	S_τ / S_Y	S_H / S_Y
Steam Generator Inlet Elbow Critical Location	48.75	19.0	3.58	-3.58	1.89	11.45	2.6	0.20	-0.20	0.10	0.60

Note:

1. SI = Stress Intensity (KSI).
2. S_Y = Yield Strength (KSI).
3. S_a = Axial Stress (KSI).
4. S_τ = Shear Stress (KSI).
5. S_H = Hoop Stress (KSI).

Table 5.4-4 Support Load Combinations and Allowable Stress	
Load Combinations	**Allowable Stress**
1. Normal (deadweight + thermal + pressure + pipe support attachments)	AISC working stresses or applicable factored load design values
2. Upset (normal + OBE)	AISC 1-1/3 working stresses or applicable factored load design values
3. Faulted (normal + DBE)	Deflections and stresses of supports limited to maintain supported equipment within their stress limits
4. Faulted (normal + pipe break + pipe whip)	Deflections and stresses of supports limited to maintain supported equipment within their stress limits
5. Faulted (normal + DBE + pipe break + pipe whip)	Deflections and stresses of supports limited to maintain supported equipment within their stress limits

Table 5.4-5

Allowable Concrete Embedment Loads

Support	Direction	Allowable Load (kips)
RPV	Downward	5136
	Horizontal	6283
Steam Generator Upper Support Guides	Perpendicular to hot leg	756
	Parallel to hot leg	635
Steam Generator Columns	Tension	827
	Shear	847
RCP Columns	Tension	1072
Tie Rods	Minimum tension(1)	1050

Note:

1. Only allowables for two tie rods attached outside the primary shield wall are provided. For all other tie rods, the tie rods extend through the primary shield wall and the allowable would be much greater.

Table 5.4-6

RCSES Stress Analysis Summary – SPU
(interaction ratios are for load Case 5, Normal + SRSS [DBE, LOCA])

Support		Maximum Interaction Ratio	Comment
1. Steam Generator Frame Structure		0.95	Axial tension plus bending on pipe stub columns(1)
2. RCP Frame Structure		0.67	Axial compression plus bending on reinforced column(2)
3. Steam Generator/RCP Tie Rods		0.32	Based on 1.33 x turnbuckle rated working load(3)
4. Equipment Pad Holddown Bolts	Steam Generator	0.85	Shear on 2.75-inch pin and tension in 0.75-inch bolts(4)
	RCP	0.59	Tension, shear on 4-inch bolt(5)
5. Embedments	Steam Generator	0.56	Uplift at column bases(6)
	RCP	0.67	Uplift at column bases(7)

Note:
The SPU did not affect the FLB and MSLB qualifications performed for the Snubber Elimination Program, and those break cases are not included in this table.

1.	Calculated axial stress = 20.6 ksi	Allowable axial stress = 41.3 ksi
	Calculated bending stress = 18.7 ksi	Allowable bending stress = 41.3 ksi
2.	Calculated axial stress = 12.2 ksi	Allowable axial stress = 23 ksi
	Calculated bending stress = 4.9 ksi	Allowable bending stress = 34.4 ksi
3.	Calculated load = 98 kips	Allowable load = 311 kips
4.	Calculated shoe uplift = 835 kips	Allowable shoe uplift = 980 kips
5.	Calculated tension load = 689 kips	Allowable tension load = 1166 kips
	Calculated shear load = 120 kips	Allowable shear load = 546 kips
6.	Calculated uplift = 460 kips	Allowable uplift = 827 kips
7.	Calculated uplift = 716 kips	Allowable uplift = 1072 kips

5.5 Reactor Coolant Pumps and Motors

The reactor coolant pumps (RCPs) at Indian Point Unit 3 (IP3) were evaluated for the stretch power uprate (SPU) in two separate areas: the structural adequacy of the pumps (subsection 5.5.1 of this report), and the acceptability of the RCP motors (subsection 5.5.2).

5.5.1 RCPs Structural Integrity

5.5.1.1 Introduction

This section addresses the ASME Code structural considerations for the pressure boundary components of the Westinghouse Model 93 RCPs. The RCP is not a Code vessel, but the IP3 RCP equipment specification requires that the design, analysis, materials, welding, inspection, and testing of the pumps meet the requirements of the ASME Code, Section III. The 1965 Edition, and later addenda and editions, are used as a basis for the design (Reference 1).

The evaluation of the RCPs for the SPU considered the SPU parameters (see Section 2 of this report), and the Nuclear Steam Supply System (NSSS) design transients (see Section 3.1 of this report), which assumed a core power of 3216 MWt.

The evaluation of the RCPs for the SPU compared the operating temperatures and pressures defined in the SPU NSSS parameters to the pressures and temperatures considered in previous analyses of the RCPs. In addition, the NSSS design transients for the SPU were compared to the transients considered in previous evaluations. For the inputs that were not enveloped by the previous analyzed parameters, stress levels were ratioed to account for the changes and the stresses were verified to remain below the allowable values.

5.5.1.2 Input Parameters and Assumptions

The Model 93 RCPs were originally designed and analyzed to meet the RCP equipment specification and the ASME Code. Evaluations of the RCPs were performed in stress analyses prepared for the original design and for the 1.4-percent measurement uncertainty recapture (MUR).

The IP3 RCPs are installed in the Reactor Coolant System (RCS) cold leg, between the steam generator outlet and the reactor vessel inlet. The temperatures and pressures used as inputs to the RCP Code structural analysis are those defined for the reactor vessel inlet in the SPU NSSS parameters (Table 2.1-2). The RCPs have been evaluated for the NSSS design transients, as defined for the RCS cold leg by the equipment specification and updated by this SPU.

5.5.1.3 Description of Analysis

Operating Temperature and Pressure

The SPU parameters (see Section 2 of this report) were used to evaluate the acceptability of the RCPs. From the SPU parameters, there are no changes from the current reactor coolant pressure of 2250 psia for any of the SPU cases. The RCS cold-leg temperature (T_{cold}), defined by the vessel inlet (RCP outlet) temperature on the SPU NSSS parameters for the IP3 SPU, is a maximum of 541.5°F. The maximum SPU RCS T_{cold} is less than the equipment specification operating temperature of 555°F and is also less than the 1.4-percent MUR T_{cold} temperature of 542.2°F. Since none of the temperatures exceeds the previously considered temperatures, and the pressure does not change, the SPU parameters are bounded by those defined in the equipment specification and used as inputs to the 1.4-percent MUR evaluation.

Table 5.5-1 summarizes the cold-leg SPU NSSS temperatures. From Table 5.5-1, the originally specified operating temperature is 555°F and the present (1.4-percent MUR) RCS T_{cold} value is 542.2°F, compared to an RCS T_{cold} range of 517.3° to 541.5°F for the SPU. Since higher temperatures correspond to lower allowable stresses, a decrease in operating temperature is conservative. Therefore, the present operating temperature bounds the maximum RCS T_{cold} temperature for the SPU. Furthermore, both conditions are bounded by the originally specified operating temperature of 555°F.

Transient Discussion

The NSSS design transients have been recalculated for the IP3 SPU. The recalculated transients have some temperature and pressure changes that are different from the design transients given in the equipment specification. The transients defined for the 1.4-percent MUR were shown to be bounded by the original equipment specification transients.

The cold leg transients applicable to the RCP evaluation are shown on Table 5.5-2. Since there is some variation in the transients considered in the original analyses, the comparison of the revised transients to the analyzed transients is approached on the basis of the original stress analyses (see Table 5.5-3).

Main Flange Bolted Joint Stress Analysis

This analysis shows that the transients other than the heatup and cooldown transients do not affect the fatigue usage of the main flange bolted joint. The cumulative usage factor (CUF) for the main flange bolts thus remains as calculated. The highest stress in the bolts occurs for the loss-of-load transient, which had a maximum pressure increase of 500 psi in the original analysis. This maximum pressure increase has now increased to 525 psi, and thus an adjustment of the maximum stress levels is required. This increase is minor, and the stresses remain within the ASME Code allowable values. The values of these stresses are shown in Table 5.5-3.

Pump Casing Stress Analysis

The transients considered in this analysis differ from the ones that were originally specified for the IP3 RCPs, and in most cases they were more severe. The exception to this is the temperature range spanned by the heatup and cooldown transients. In the original analysis, the temperature range considered was 433°F, while the IP3 temperature range is 447°F. The maximum values of the stress intensity occurred at the suction nozzle area of the casing. Adjusting the calculated thermal stresses for this difference results in small increases in the primary-plus-secondary stress intensity and the maximum thermal-plus-pressure-plus mechanical stress intensity. The stress intensities remain less than the ASME Code allowable values. The values of these stress intensities are shown in Table 5.5-3.

Support Foot Analysis

The support foot is considered a structural member in the original analysis and is analyzed only for mechanical loads. There is no transient analysis.

Auxiliary Nozzles

The original auxiliary nozzle analysis was prepared specifically for IP3. This analysis addressed the seal injection, No.1 seal leak off, and No. 2 seal leak off nozzles, and the component cooling water inlet and outlet nozzles for the thermal barrier heat exchanger, the motor upper bearing oil cooler, and the motor lower bearing oil cooler. The analysis that was performed was based on the loads that were applied to the auxiliary nozzles, and the internal pressure within the auxiliary nozzles. No cold leg transients were considered in the analysis. Thus, there is no effect from changes to the cold leg transients.

5.5.1.4 Acceptance Criteria

The acceptance criteria for the ASME Code structural analysis of the RCP pressure boundary are that the analyzed stresses do not exceed the stress allowables of the ASME Code and that the CUFs from the Code fatigue analysis remain less than 1.0. This can be demonstrated by showing that the design inputs for the SPU are either unchanged or bounded by the design inputs used in previous analyses, which show that the RCPs meet the ASME structural integrity criteria. For those inputs that are not bounded by the inputs used in previous analyses, then adjusted stresses or usage factors are calculated and compared to the ASME Code allowables.

5.5.1.5 Results

The operating temperature and pressure discussion presented in subsection 5.5.1.3 showed that the operating temperatures and pressures are unchanged or bounded by those considered for previous analyses and evaluations, as shown in Table 5.5-1.

For the NSSS design transients, the original stress analyses and evaluations have been shown to be applicable to the current SPU conditions, with the exception of some stresses in the main flange bolts and in the casing that have been adjusted to incorporate the effects of revised design transients. The adjusted stresses continue to meet the ASME Code allowable values that were considered in the original analyses. The cumulative usage factors are not affected by the SPU and the RCPs remain within the ASME Code requirements. A summary of the peak stresses and cumulative usage factors is provided in Table 5.5-3.

5.5.1.6 Conclusions

The stresses and CUFs resulting from the SPU parameters and NSSS design transients have been shown to be bounded by the stresses and CUFs resulting from the parameters and transients considered in the original analyses and evaluations, or have been recalculated and shown to continue to be in compliance with the ASME Code allowable values. The RCPs are acceptable from a structural standpoint. The RCP pressure boundary parts still comply with the ASME Code originally specified or later editions. Therefore, the evaluation results of the SPU for the RCP structural evaluation are consistent with and continue to comply with the current licensing basis and acceptance requirements for IP3.

5.5.2 Reactor Coolant Pump Motors

5.5.2.1 Introduction

This section addresses the performance of the RCP motors. The RCP motors are evaluated for the IP3 SPU parameters and best-estimate flows, which assumed a core power of 3216 MWt.

5.5.2.2 Input Parameters and Assumptions

The input parameters considered in the evaluation of the RCP motors are the steam generator outlet temperatures and the best-estimate flows defined for the IP3 SPU. These parameters are considered for the IP3 Model 93 RCPs containing impeller serial numbers 320, 321, 323, and 1561, and for spare impeller serial number 322.

5.5.2.3 Description of Analysis

The steam generator outlet temperatures and best-estimate flows are considered in a hydraulic analysis using the operating characteristics of the IP3 RCPs. This hydraulic analysis calculates the power requirements for the impeller that operates at the highest cold power. For the IP3 SPU, the power requirements from this analysis for hot-loop and cold-loop operation were compared to the hot and cold nameplate ratings for the motors. The power requirements for the SPU were determined to be within the nameplate ratings of the motors. Therefore, the RCP motors are acceptable for the SPU.

The IP3 SPU evaluated the RCP motor loading in three areas:

- Continuous operation at hot-loop temperatures and flows
- Continuous operation at cold-loop temperatures and flows
- Thrust-bearing loading

5.5.2.4 Acceptance Criteria

For the IP3 SPU, the acceptance of the RCP motor loading is based on the hot and cold brake horsepower requirements being within the nameplate ratings of the motors. The motors have been shown by test and analysis to operate within the equipment specification limits at the nameplate ratings. Per design, motor operation is acceptable for any load up to the hot nameplate rating of 6000 horsepower (hp) and the cold loop nameplate rating of 7500 hp.

Per the original equipment specifications, the temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 120°F must be in accordance with the National Electric Manufacturers' Association (NEMA) Standard MG1-20.40-1963.

Per the equipment specifications, the motor is required to drive the pump for up to 50 hours (continuous) and 3000 hours maximum over the 40-year design life under cold-loop conditions.

The thrust-bearing loading used for the motor design is given in the equipment specifications. Performance of the thrust bearings in an RCP motor can be adversely affected by excessive or inadequate loading. The thrust-bearing loading for the revised conditions is compared to the design thrust-bearing loading to determine continued acceptability.

5.5.2.5 Results

The worst case loads for the RCP motors were calculated for the IP3 SPU operating conditions. The new worst-case hot-loop load under the revised operating conditions is 5969 hp. The new worst-case cold-loop load under the revised operating conditions is 7425 hp. These loadings are less than the motor nameplate ratings of 6000 hp for hot-loop operation and 7500 hp for cold-loop operation. Thus, the revised motor loadings are acceptable based on the loadings being within the nameplate ratings for the motors.

The evaluations of the RCP motors that are the basis of the IP3 SPU conclusions are described in the following paragraphs.

Continuous Operation at Hot-Loop Conditions

The worst-case hot-loop operating load for the SPU is 5969 hp, which is below the nameplate rating of the motor, 6000 hp. Since the loading is within the nameplate rating of the motor, it is acceptable without further calculations.

Continuous Operation at Cold-Loop Conditions

The worst-case cold-loop operating load of 7425 hp for the SPU is below the nameplate cold-loop rating of the motor, 7500 hp. Since the loading is within the cold nameplate rating of the motor, it is acceptable without further calculations.

Thrust-Bearing Loading

The thrust-bearing loadings for the IP3 SPU conditions indicate a reduction in the thrust-bearing load of 6024 lbs for hot-loop operation, and an increase of 2674 lbs for cold-loop operation. In comparison to the normal operating thrust-bearing load of 101,200 lbs, these changes are not considered significant and the thrust bearings are acceptable for the SPU loads.

Motor Ambient Temperature

The temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 130°F will continue to meet National Electric Manufacturers' Association (NEMA) Standard MG1-20.40-1963.

5.5.2.6 Conclusions

The RCP motors are evaluated in three areas for the IP3 SPU conditions, under loadings of 5969 HP for worst-case hot-loop operation and 7425 HP for worst-case cold-loop operation. Since the new RCP motor loads are within the nameplate ratings of the motors the motor, temperature rise for hot and cold operating conditions will be within the NEMA requirements and the first two areas meet requirements. In comparison to the normal operating thrust-bearing load of 101,200 lbs, the SPU changes are not considered significant and the thrust bearings remain acceptable for the SPU loads. Therefore, the RCP motors at IP3 are acceptable for operations at the SPU conditions.

5.5.3 References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition with later Editions and Addenda, The American Society of Mechanical Engineers, New York, NY.

Table 5.5-1 SPU NSSS Conditions Used to Bracket All Operating Conditions				
	Equipment Specification	Present (1.4-percent MUR Program)	SPU	
Parameter	Operating Temperature	Operating Temperature	High T_{avg}	Low T_{avg}
T_{cold} (vessel inlet)	555°F	542.2°F	541.5°F	517.3°F

Table 5.5-2 Cold Leg Thermal Transient Summary for RCP Evaluation for IP3 SPU(1)			
	Thermal Transient ΔT (°F)	Pressure Transient ΔP (psi)	Occurrences
Normal Condition			
Heatup/Cooldown	[		]a,c,e
Unit Loading/Unloading at 5% of Full Power			
Step Increase/Decrease of 10% Full Power			
Large Step-Load Decrease with Steam Dump			
Steady-State Fluctuations			
Upset Condition			
Loss of Load			
Partial Loss of Flow			
Reactor Trip from Full Power			

Notes:

1. The number of occurrences of the transients, and the pressure and temperature changes for heatup, cooldown, and the steady-state fluctuations, are taken from the RCP equipment specification. The other pressure and temperature changes are those defined for the SPU.

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.5-3

RCP Stress and Fatigue Evaluation for IP3 SPU

RCP Component	Max Stress Intensity (psi)[1]		Allowable (psi)[1]	Cumulative Usage Factor	ASME Code
	Original Value	Recalculated Value		No Usage Factors Were Recalculated	
Casing[2]	[			]a,c,e	1965
Main Flange Bolting					1965

Notes:

1. The ASME Code year used as the basis for the allowable stress is listed in the "ASME Code" column of this table.
2. The three values given are for primary general membrane stress intensity, primary membrane plus bending stress intensity, and primary plus secondary membrane plus bending stress intensity. The corresponding allowable stresses are equal to S_m, 1.5 S_m, and 3 S_m, where S_m is 16,700 psi.

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.6 Steam Generators

Evaluations of the thermal-hydraulic performance, structural integrity, and mechanical hardware have been performed to address operation of the Indian Point Unit 3 (IP3) steam generators at stretch power uprate (SPU) conditions.

5.6.1 Thermal-Hydraulic Evaluation

The thermal-hydraulic evaluations of the IP3 Model 44F steam generators focused on the changes to secondary side operating characteristics at the proposed SPU conditions. The SPU design operating conditions considered are presented in Table 2.1-2 of this report. The evaluations discussed in this section were performed to confirm the acceptability of the steam generator secondary side parameters. Four cases were analyzed at the 3230-MWt Nuclear Steam Supply System (NSSS) power corresponding to the 3216-MWt core power conditions: two Reactor Coolant System (RCS) primary average temperatures (T_{avg}), 549.0° and 572.0°F, and two steam generator tube plugging (SGTP) levels, 0 and 10 percent.

The four cases are distinguished as follows:

Case 1 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 0-percent SGTP.

Case 2 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 10-percent SGTP.

Case 3 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 0-percent SGTP.

Case 4 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 10-percent SGTP.

Each case was evaluated for two feedwater temperatures, 390.0° and 433.6°F. The low feedwater temperature cases are referred to as case "a" (such as Case 2a), while the high temperature cases are referred to as case "b" (such as Case 2b) for this section of the report. The steam generator secondary side operating characteristics at the SPU conditions are compared with a reference case for the current (100-percent power) condition. The results of the thermal-hydraulic evaluations are summarized in Table 5.6-1. Based on these evaluations, the IP3 steam generators are qualified to operate at the SPU conditions with up to 10-percent SGTP.

Methodology

A number of secondary side operating characteristics are considered to assess the acceptability of steam generator operation at various operating conditions. These operating characteristics include peak heat flux, margin to departure from nucleate boiling (DNB) transition, moisture carryover (MCO), hydro-dynamic stability, and secondary side pressure drop. The calculation of these steam generator characteristics was accomplished using two programs: the GENF code and the ATHOS code.

GENF is a one-dimensional steady-state thermal and hydraulic performance code developed by Westinghouse specifically for feed-ring steam generators. The code has been verified and is maintained under Westinghouse Configuration Control. GENF calculates the overall primary side heat balance based on the thermal power and the primary flow rate, outlet temperature, and operating pressure. On the secondary side, the code determines the secondary side saturation pressure in the tube bundle using an iterative procedure. The steam outlet pressure is then calculated by subtracting all losses from the bundle region to the steam nozzle outlet. The steam outlet pressure is used to determine steam flow rate via the secondary side heat balance and feedwater inlet temperature. The steam generator operating characteristics obtained using the GENF code, including the circulation ratio, secondary side pressure drop, fluid masses, and stability damping factor, are shown in Table 5.6-1.

The ATHOS code was used to evaluate the potential for local tube dryout or margin to DNB. ATHOS is a three-dimensional computer program for computational fluid dynamics analysis of steam generators. The ATHOS code was developed under the sponsorship of the Electric Power Research Institute (EPRI). The ATHOS code consists of a geometry pre-processor, a thermal-hydraulic (ATHOS) solver, and a post-processor module. The geometry pre-processor simulates the detailed geometry. This geometry simulation includes the detailed tube layout, tube lane blocks, flow distribution baffle (FDB), tube support plates (TSPs), anti-vibration bars (AVBs), and opening of the primary separators. The ATHOS module uses the pre-processor data to calculate the primary and secondary side thermal-hydraulic parameters in the steam generator. The ATHOS code calculates both heat flux and tube wall temperature in addition to typical parameters such as liquid velocity, vapor velocity, and steam quality for a two-phase flow like that in the secondary side of a steam generator.

The ATHOS code for the analysis of steam generators has been verified and qualified by EPRI and Westinghouse. The Westinghouse-developed post-processors process the large amount of output from the ATHOS calculation. Their capabilities include velocity vector plots and contour plots of thermal-hydraulic parameters, such as steam quality, velocity, heat flux, and critical steam quality corresponding to DNB. DNB ratios obtained using the ATHOS code are shown on the last line of Table 5.6-1.

Steam Pressure

Steam pressure is affected by both the available heat transfer area in the tube bundle and the average primary fluid temperature. For the current 100-percent power conditions, the steam pressure is calculated to be 766.18 psia using the Westinghouse GENF code. With the SPU and T_{avg} of 549.0°F, the GENF code shows a decrease in steam pressure to a minimum of [ ]^{a,c,e} psia. With the SPU and T_{avg} of 572.0°F, the GENF code shows a decrease to a minimum of [ ]^{a,c,e} psia. Both of these maximum steam pressure drops occur at a 10-percent SGTP level and are within the acceptable range.

Heat Flux

Average heat flux in the steam generator is directly proportional to heat load and inversely proportional to the heat transfer area in service. For the 0-percent SGTP case, the average heat flux increases from [ ]^{a,c,e} Btu/hr-ft^2 at 100-percent power to [ ]^{a,c,e} Btu/hr-ft^2 at SPU conditions. With 10-percent SGTP and SPU conditions, the average heat flux increases to [ ]^{a,c,e} Btu/hr-ft^2.

Tube Dryout

A measure of the margin for DNB transition in the tube bundle is the DNB index, which is the ratio of the local quality (x) to the estimated quality at DNB transition. The ATHOS code was used to estimate the DNB index of the limiting case for the SPU conditions. Based on the results of the ATHOS program, the highest DNB indexes occur on the hot leg side near the center of the steam generators. The maximum DNB index predicted has a value of [ ]^{a,c,e} and occurs at a small area near the top of the U-bend region. Since the DNB index remains less than 1.0 for the limiting SPU conditions, the whole tube bundle is expected to be within nucleate boiling regime and thus no local tube dryout is expected for any of the SPU conditions.

Moisture Carryover

The performance of moisture separator packages is primarily determined by three operating parameters: steam flow (power), steam pressure, and water level. For the moisture separator performance data evaluation, steam flow and steam pressure are combined into a single parameter designated as the separator parameter (SP). A correlation for MCO as a function of SP is used to predict MCO at desired conditions. The values of the SPs for the IP3 SPU conditions were calculated using the results of the GENF program. The MCO was calculated to possess a maximum of 0.01508 percent of steam flow at the SPU conditions with 10-percent SGTP. Therefore, the MCO is predicted to remain well below the 0.10-percent design limit for SPU conditions.

Hydro-Dynamic Stability

The hydro-dynamic stability of a steam generator is characterized by its damping factor. A negative value of the damping factor indicates that any disturbance to the thermal-hydraulic parameters (for example, flow rate or water level) will rapidly reduce in amplitude and the steam generator will return to stable operation. For the SPU conditions, the damping factor was calculated by the GENF program to range from [ ]^{a,c,e} hr^{-1}, meaning that even the largest damping factor calculated is substantially negative. Therefore, the IP3 steam generators will continue to operate in a hydro-dynamically stable manner at the SPU operating conditions.

Steam Generator Secondary Fluid Inventory

Secondary side fluid inventory consists of the masses of the liquid and the vapor phases. With the proposed SPU, the secondary side fluid liquid mass may vary from [ ]^{a,c,e} lbm. This is a variation of -6.96 percent and +2.73 percent relative to the 100-percent power fluid mass of [ ]^{a,c,e} lbm. The secondary side vapor mass may vary from [ ]^{a,c,e} lbm. This is a variation of -23.43 to -0.99 percent relative to the 100-percent power fluid mass of [ ]^{a,c,e} lbm. Finally, the total secondary side fluid (liquid + vapor) inventory is calculated to vary from [ ]^{a,c,e} lbm for the SPU conditions. These small changes in secondary side fluid inventory are judged to have no effect on operation.

Steam Generator Secondary Side Pressure Drop

The secondary side pressure drop (from the feedwater nozzle the steam exit nozzle) is predicted by GENF program to vary from [ ]^{a,c,e} psi as a result of the SPU. The secondary side pressure drop for the current 100-percent power condition is calculated to be [ ]^{a,c,e} psi. The largest secondary side pressure drop, [ ]^{a,c,e} psi, is predicted with

10-percent SGTP and a T_{avg} of 549.0°F, while the smallest secondary side pressure drop, [ ]^{a,c,e} psi, is predicted with 0-percent SGTP and a T_{avg} of 572.0°F. The small fluctuations in secondary side pressure drop should have no significant effect on the feed system operation.

Thermal-Hydraulic Evaluation Conclusion

In conclusion, the thermal-hydraulic characteristics of the IP3 Model 44F steam generators are within acceptable ranges for the SPU conditions with a SGTP level of 10 percent or less.

5.6.2 Structural Integrity Evaluation

The structural evaluation for the SPU focused on the critical steam generator components. The critical components are those whose primary-plus-secondary stress ranges without peak and stress ranges with peak in fatigue calculations are affected due to the reduction of steam pressure, which results in higher ΔP between primary and secondary side, for the SPU conditions. The critical components are affected by changes in the pressure and temperature in the primary and secondary side of the steam generator. The following critical primary side components were evaluated: divider plate, tubesheet and shell junction, tube-to-tubesheet weld, and tubes. The critical secondary side components included: feedwater nozzle, secondary manway studs, and steam nozzle.

Comparisons of the primary side transients and RCS parameters were performed to determine the scale factors that were applied to the baseline analyses maximum stress ranges and fatigue usage factors. The scale factor was applied to the baseline analysis results for various components to obtain the values for the SPU conditions.

For the primary side components (particularly the divider plate, the tubesheet and shell junctions, the tube-to-tubesheet weld, and tubes), the applicable scale factors were the ratios of the primary-to-secondary-side differential pressure for the baseline and SPU conditions.

The scale factors are applied to the stress ranges that are a combination of both thermal and pressure stresses, and the revised stress ranges are used to calculate the revised alternating stress and the fatigue usage.

For the secondary side components, such as the feedwater nozzle and secondary manway bolts/studs, the decrease in secondary side pressure was the basis for the scale factors. The reduced pressure results in an increased stress range during transient events. The increase in stress range due to the reduced pressure is added to the baseline stress range to evaluate the revised stress range and the revised fatigue usage.

Input Parameters and Assumptions

The SPU structural evaluation was performed for 3230-MWt NSSS power and 10-percent SGTP. The 10-percent SGTP case is the most conservative of the proposed operating cases. The applicable NSSS design parameters used for the steam generator's structural evaluation are shown in Table 2.1-2 of this document. The design transients and the results of the steam generator primary-to-secondary side ΔP calculation (discussed in subsection 5.6.3), were used to generate scaling factors with respect to the design basis stress reports results. The scaling factors were based on the existing design basis steam temperature of 513.8°F, corresponding to a steam pressure of 770 psia.

The NSSS design plant operating conditions provide for both a low T_{avg} temperature operating condition case and a high T_{avg} temperature operating condition (see Table 2.1-2). The low T_{avg} case results in a lower steam pressure (and, therefore, a greater primary-to-secondary side ΔP) and, as such, will envelop the high T_{avg} case. On this basis, the bounding scale factors based on low T_{avg} were used to perform a bounding evaluation of the critical components.

The scale factors calculated based on the differential pressure are applied conservatively on the stress intensities that are due to both pressure and thermal loads, since the scale factors based on pressure will envelop the scale factors based on thermal loads. The evaluation based on scale factors due to ΔP is conservative, since the thermal variation is small.

Description of Analyses and Evaluations

This structural evaluation was performed for the bounding condition for low T_{avg} case, where P_{stm} = 650 psia. The existing design basis evaluation corresponds to the reference NSSS design parameter case of P_{stm} = 770 psia. Scale factors are calculated based on the revised steam pressure at the SPU operating conditions.

Primary Side Components

For primary side components, the scale factor is based on the change in the primary-to-secondary side differential pressure and was calculated based on the following equation:

[ ] a,c,e

Secondary Side Components

Secondary side components, such as the feedwater nozzle, steam nozzle and secondary manway studs, are subjected to only the steam pressure. Therefore, the scale factor is calculated based on the reduced steam pressure during transient events.

The calculated scale factors were applied to the stress ranges for all applicable transient combinations involved in the original reference analysis.

Applying the scale factors to the design basis stresses approximates the stress and fatigue usage values that would occur during operation at the SPU conditions.

Acceptance Criteria

The acceptance criteria for each component are consistent with the criteria used in the design basis analysis for that component. The maximum range of primary-plus-secondary stresses was compared with the corresponding $3S_m$ limits of the ASME Boiler and Pressure Vessel (B&PV) Code, 1965 Edition through Summer 1966 Addenda (Reference 1). For situations in which these limits were exceeded, a plastic analysis or simplified elastic-plastic analysis was performed consistent with the original design basis analysis to meet the American Society of Mechanical Engineers (ASME) Code Section III limits. Results of these original analyses were updated for the SPU conditions.

A cumulative fatigue usage factor less than or equal to unity demonstrates the adequacy of the steam generators for a 40-year design life.

Results

The results of the evaluation show that all components analyzed meet ASME Code Section III limits for a 40-year design life. The results of the evaluation are summarized in Table 5.6-2.

5.6.3 Evaluation of Primary-to-Secondary Side Pressure Differential

An analysis was performed to determine if ASME B&PV Code, (Reference 1) limits on the Model 44F replacement steam generator (RSG) design primary-to-secondary ΔP are exceeded for any of the applicable transient conditions for the SPU parameters (Table 2.1-2). The design pressure limit for primary-to-secondary pressure differential is 1700 psi, as defined in the applicable design specification.

The normal/upset transient conditions are subject to the following design pressure requirements:

- Normal Condition Transients: Primary-to-secondary pressure gradient should be less than the design limit of 1700 psi.

- Upset Condition Transients: If the pressure during an upset transient exceeds the design differential pressure limit, the stress limits corresponding to design conditions apply using an allowable stress intensity value of 110 percent of those defined for design conditions. In other words, as long as the upset condition pressure differential values are less than 110 percent of the design pressure differential values, no additional analysis is necessary. For the IP3 steam generators, 110 percent of the design pressure differential limit corresponds to 1870 psi.

The primary-to-secondary pressure differential evaluation was based on the transient parameters discussed in Section 3.1 of this report and the corresponding full-power conditions that are defined in Table 2.1-2 of this document. The pressure differentials across the primary-to-secondary side pressure boundary are calculated for these defined full-power conditions. Note that the evaluation was performed for the 10-percent SGTP condition since increased levels of plugging result in greater primary-to-secondary pressure differentials. Therefore, the 10-percent SGTP case bounds all other cases.

The analysis determined that the maximum normal/upset operating condition primary-to-secondary side differential pressures (based on Table 2.1-2 of this document) for high T_{avg} operation would be [ ]^{a,c,e} psi for normal operating condition transients, and [ ]^{a,c,e} psi for upset condition transients. For the low T_{avg} operating conditions, the maximum pressure differentials (based on Table 2.1-2 of this document) are [ ]^{a,c,e} psi for the normal and upset conditions, respectively. The results show that the maximum primary-to-secondary pressure gradients are less than the allowable values of 1700 and 1870 psi for normal and upset operating conditions, respectively. Therefore, the design pressure requirements of the ASME Code continue to be satisfied.

5.6.4 Evaluations for Repair Hardware

The IP3 RSGs entered service in 1989. During the fabrication on 1 of the steam generators, several Westinghouse shop welded plugs were installed. These components were re-evaluated for the operating conditions and transients associated with SPU operation.

In anticipation of future needs, both "long" and "short" 7/8-inch ribbed mechanical plugs were qualified for installation in the Model 44F RSGs for the SPU operating conditions. In addition, since there are circumstances that may require tube ends to be reamed, a 40-percent tube wall undercut was considered. The resulting reduced tube mouth weld joint geometry is qualified for continued service. Also, if a future need arises that a steam generator tube may require stabilization, evaluations were performed to qualify collar-cable tube stabilizers and bare-cable stabilizers.

Mechanical Plugs

The enveloping condition for the Westinghouse mechanical plug (Alloy 690 plug shell material) results in the largest pressure differential between the primary and secondary sides of the steam generator. Both the SPU parameter changes and the updated NSSS design transients were used to determine the effect of the SPU on the mechanical plugs. The most critical set of parameters for the mechanical plug evaluation are those for the primary side hydro-static pressure test in which the differential pressure across the plug is [ ]a,c,e psi and is independent of the SPU.

Description of Evaluation

A structural evaluation was performed for both "long" and "short" Westinghouse 7/8-inch ribbed mechanical plugs for both the 1.4-percent Measurement Uncertainty Recapture (MUR) Program and the SPU conditions. This evaluation was performed to the applicable requirements of ASME B&PV Code (Reference 1).

Acceptance Criteria

The Westinghouse mechanical tube plug was evaluated for the changes to the NSSS transients due to the SPU. The primary stresses due to design, normal, abnormal, and test conditions must remain within the respective Code allowable values (Reference 1). The maximum range of primary-to-secondary stresses is limited to $3S_m$. The cumulative fatigue usage factor must be less than or equal to 1.0, or the ASME fatigue exemption rules must apply, for a 40-year fatigue life for the plug. In addition to the stress criteria, plug retention must be ensured.

Results

The critical loading parameter from the design of the plug shell is the primary-to-secondary differential pressure. The plug qualification was based on a primary pressure of 2485 psig. The maximum design primary-to-secondary differential pressure of 1700 psi for plug retention was also addressed.

All stress/allowable ratios are less than unity, indicating that all primary stress limits are satisfied for the plug shell wall between the top land and the plug end cap. The plug meets the Class 1 fatigue exemption requirements per N- 415.1 of the ASME B&PV Code (Reference 1). It was also determined that adequate preload and friction are available to prevent dislodging of the plug for the limiting steady-state and transient loads.

Since this is a component that is installed into the steam generator after original fabrication is complete, and since this part is typically fabricated to the requirements of the 1989 ASME Code Edition (Reference 2), an evaluation was conducted based on the 1989 Code year requirements. It was determined that the mechanical plug is also acceptable for the SPU operating conditions based on the 1989 ASME Code Edition.

Conclusions

Results of the analyses performed for the mechanical plug for IP3 show that both the long and short mechanical plug designs satisfy all applicable stress and retention acceptance criteria at the SPU operating conditions with up to 10-percent SGTP.

Shop Weld Plugs

The Westinghouse shop weld plugs are fabricated from ASME SB-166, Alloy 600 rod material. The minimum yield for this material is 35,000 psi. Since several design transients were revised for the SPU conditions, a revised analysis was performed to qualify the plugs for the revised conditions.

Description of Evaluation

A structural evaluation was performed for the existing shop weld tube plugs for the SPU operating conditions. The evaluation was performed to the applicable requirements of the ASME B&PV Code (Reference 1).

Acceptance Criteria

The primary stresses due to design, normal, abnormal, and test conditions must remain within the respective ASME Code allowable values (Reference 1). The maximum primary-to-secondary stresses are limited to $3S_m$. The cumulative fatigue usage factor must be less than or equal to 1.0, or the ASME fatigue exemption rules must apply, for a 40-year fatigue life for the plug.

Results

The evaluation of the weld plug first addressed the design condition. A vertical minimum weld thickness critical plane around the perimeter (circumference) of the weld plug was considered. The design pressure differential of 1700 psi between the primary and secondary was applied to the plug.

Test conditions for the primary hydro-static and secondary hydro-static tests were then evaluated. Values for primary stresses, primary stresses plus secondary stresses, and primary-to-secondary stress range intensities were calculated. All stress values were determined to be acceptable.

The normal and abnormal conditions were then reviewed. It was determined that the controlling transient for both the normal and abnormal conditions was the "loss of load" transient. The differential pressure considered was [ ]^{a,c,e} psi. This was the controlling pressure condition for the baseline transient conditions. It was determined that the stress limits are acceptable for the controlling differential pressure. However, the governing differential pressure for the SPU was calculated at [ ]^{a,c,e} psi.

The last step in the evaluation process considered fatigue. The approach was to investigate if the weld plug would be exempt from an explicit usage factor calculation based on the ASME requirements for fatigue exemption. The six required fatigue exemption conditions were determined to be satisfied. Therefore, it was concluded that the welded plug does meet the ASME Code cycle load fatigue limits for the SPU.

Conclusions

All primary stresses are satisfied for the weld between the weld plug and the tubesheet cladding. The overall maximum primary-plus-secondary stresses for the enveloping transient case of "loss of load" was determined to be acceptable. The fatigue evaluation for the weld plug used the ASME fatigue exemption rules. It was determined that the fatigue exemption rules were met, and therefore, fatigue conditions are acceptable.

Tube Undercut Qualification

It may be necessary to field machine steam generator tube mouth ends to modify and repair tubes (that is, plugging, sleeving, and tube end reopening). It is sometimes necessary to remove a portion of the tube and weld material with a machining process (drilling and reaming) when removing a Westinghouse mechanical plug. The structural evaluation performed for the SPU conditions addressed the acceptability of up to a 0.020-inch (40-percent of the 0.050-inch tube wall) undercut of the tube wall thickness. The evaluation was performed to the applicable requirements of ASME B&PV Code (Reference 1).

Description of Evaluation

Past structural evaluations for steam generator tube-end machining have been performed for various steam generator models. The approach for the IP3 tube-end evaluation was to use the results from a previous evaluation and adjust the stress values from the past project as appropriate to address the applicable NSSS transients for the SPU operating conditions.

Acceptance Criteria

The primary stresses due to design must remain within the respective ASME Code allowable values (Reference 1). The maximum range of stress intensities is limited to $3S_m$. The cumulative fatigue usage factor must be less than or equal to 1.0, or the ASME fatigue exemption rules must apply, for a 40-year fatigue life for the undercut tube.

Results

The approach for the IP3 tube-end evaluation was to use the results from past structural evaluations for steam generator tube-end machining and adjust the stress values from the past project as appropriate for design transient changes. The adjustment value was conservatively based on the increase in a differential pressure for the SPU across the tubesheet. It was determined from the results that all revised stresses for the SPU conditions are within ASME Code allowable values.

A similar approach, using stress factors based on increased pressure differentials, was used to evaluate fatigue in the undercut tube. It was determined that fatigue usage values, when adjusted for the SPU conditions, remain acceptable.

Conclusions

The stress evaluation of undercut tubes in the IP3 model 44F steam generators determined that the stresses are within ASME Code allowable values. Also, the fatigue usage factors were determined to remain less than 1.0.

Collar-Cable-Stabilizer Qualification

The Westinghouse collar-cable stabilizer consists of a central coaxial cable made up of Type 302 stainless steel wire strands protected over the full length of the stabilizer by several Type 304 stainless steel tubular collars, which are swaged onto the cable. The swaged collars are about 8-inches long with a longitudinal space of about 1-inch between the adjacent collar segments. This arrangement provides flexibility and dynamic damping.

Description of Evaluation

The qualification method was employed to show that the wall of an assumed hypothetical fully severed host tube would wear out before the stabilizer collar wore away, should a random wear couple form between the severed host tube and the stabilizer collar. Under these conditions, the central coaxial cable of the stabilizer would remain intact and protected by the collar remnant for the life of the installation. The evaluation approach was based on the relative wear coefficients and cross-sectional areas of the tube and stabilizer, and is independent of the dynamic fluid forces causing potential random vibration of the assumed severed host tube.

Acceptance Criteria

The design intent of the Westinghouse cable stabilizer is that the local tube wall wears out totally before the tubular segment of the stabilizer wears out, thereby providing positive protection from wear of the stabilizer's central co-axial cable for the life of the installation. Also, the worn stabilizer remnant should prevent significant contact with the adjacent tubes.

Results

The qualification was based solely on geometric parameters and the relative wear coefficients between the stabilizer collars and the host tube materials. Should a potentially unstable dynamic condition occur and the tube starts to wear against the stabilizer collar, the tube wall was determined to essentially wear through before the collar wears through (which protects the central co-axial cable for the life of the installation). Also, potentially deleterious contact with adjacent active tubes was determined not to occur.

Conclusions

The evaluation of the straight leg collar-cable tube stabilizer for IP3 model 44F steam generators determined that the 0.625-inch diameter stabilizer is acceptable for use in the 0.875-inch diameter, 0.050-inch nominal wall tubes, for operation at the SPU conditions.

Bare-Cable Stabilizer Qualification

The Westinghouse bare-cable stabilizer's function is to retain severed tubes, to dampen vibration and to mitigate additional wear on plugged steam generator tubes. The tube stabilizer is fabricated from 0.5-inch diameter 6 x 19 Type 304 stainless steel wire rope. It has a lower end fitting that allows it to be installed with a typical probe pusher. The upper end of the stabilizer is capped with a welded bullet nose to facilitate installation. This stabilizer is used in the same manner as the collar -cable stabilizer discussed previously.

Description of Evaluation

It has been previously demonstrated that the bare-cable tube stabilizer is acceptable generically for use in Westinghouse-designed steam generators with 7/8-inch tubing. The generic design was based on the original Sequoyah Units 1 and 2 steam generators and is generally applied to defects below the first tube support. However, longer lengths of this stabilizer design can be applied to defects anywhere along the straight length of the tubing. A review of the generic bare-cable stabilizer analysis and the SPU thermal-hydraulic conditions shows that the existing qualification of the stabilizer remains valid for the SPU conditions at IP3.

Both IP3 and Sequoyah have similar Westinghouse steam generator designs. The tube support geometry for both designs is essentially the same except the Model 44F steam generators at IP3 have a flow distribution baffle (FDB) located approximately 23 inches up from the secondary face of the tubesheet. However, this baffle is not assumed to provide any support for the tubes. Thus, the free-span region of the tube at the entrance to the tube bundle is essentially the same for both steam generator designs. Other assumptions used in the generic bare-cable stabilizer analysis (for example, threshold instability constant, tube inside diameter [ID] and outside diameter [OD], damping ratio, etc.) are the same for both Sequoyah and IP3.

Comparisons of the SPU operating conditions for IP3 and those considered in the qualification of the stabilizers for Sequoyah were used to determine the applicability of the generic analysis to IP3.

Acceptance Criteria

The bare-cable stabilizer design is considered qualified if the tube with the stabilizer installed remains fluid-elastically stable for operation at the SPU conditions. That is, the stability ratio of a tube with a bare-cable stabilizer must be less than or equal to 1.0.

Results

A review of the thermal-hydraulic analysis shows that the SPU results in a maximum increase in fluid velocities at the tube bundle entrance of no more than 3-percent. More significantly, the dynamic pressure (ρV^2) of the fluid against the tubes increases by approximately 4-percent for the worst case analyzed. To account for these potential differences, the previous generic bare-cable stabilizer evaluation included secondary side flow velocities increased by 50 percent and the unsupported tube span at the tube bundle entrance lengthened by 25 percent. Even with these overly conservative assumptions, the stability ratio remains less than 1.0, and the tube movements would be less than the defined limits, as such the results are acceptable. Thus, the existing qualification for the bare-cable stabilizer is bounding for the SPU operating conditions proposed for the IP3 steam generators.

Conclusions

The bare-cable tube stabilizer is acceptable for use in the IP3 steam generator at the SPU conditions.

5.6.5 Regulatory Guide 1.121 Analysis

The heat transfer area of steam generators in a pressurized water reactor (PWR) NSSS comprises over 50 percent of the total primary system pressure boundary. The steam generator tubing, therefore, represents a primary barrier against the release of radioactivity to the environment. For this reason, conservative design criteria have been established for the maintenance of tube structural integrity under the postulated design basis accident (DBA) condition loadings in accordance with Section III of the ASME Code.

Over a period of time under the influence of the operating loads and environment in the steam generator, some tubes may become degraded in local areas. Partially degraded tubes are satisfactory for continued service as long as the defined stress and leakage limits are satisfied, and as long as the prescribed structural limit is adjusted to account for possible uncertainties in the eddy current inspection and an operational allowance for continued tube degradation until the next scheduled inspection.

NRC Regulatory Guide (RG) 1.121 (Reference 3) describes an acceptable method for establishing the limiting safe condition of tube degradation beyond which tubes determined to be defective by the established in-service inspection should be removed from service. The level of acceptable degradation is referred to as the "repair limit." For tube cracking due to fatigue and/or stress corrosion, a specification on maximum allowable leak rate during normal operation must be established so that a reasonable likelihood that "leak-before-break" would be achieved. If the leak rate exceeds the specification, the plant must be shut down and corrective actions taken to restore the integrity of the unit. The EPRI *PWR Primary-to-Secondary Leak Guidelines* (Reference 4) form the basis of the plant's operational leakage program.

Description of Evaluation

An analysis has been performed to define the "structural limits" for an assumed uniform thinning mode of degradation in both the axial and circumferential directions. 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 repair limit, in accordance with RG 1.121

(Reference 3), is obtained by incorporating a growth allowance for continued operation until the next scheduled inspection and also an allowance for eddy current measurement uncertainty into the resulting structural limit. Calculations have been performed to establish the structural limit for the tube straight leg (free-span) region of the tube for degradation over an unlimited axial extent, and for degradation over limited axial extent at the TSP, FDB, and AVB intersections.

Results and Conclusions

A summary of the tube structural limits as determined by this analysis for both the high T_{avg} and low T_{avg} operating conditions is provided in Table 5.6-3. The corresponding repair limits are established by subtracting from the structural limits an allowance for eddy current uncertainty and continued growth. The reduced minimum tube wall thickness (t_{min}) requirements established for the AVB intersections in Table 5.6-3 only apply for tube rows 17 and higher. The t_{min} requirements and structural limits corresponding to the straight leg are to be used for AVB intersections in tube rows 9 to 16.

5.6.6 Tube Vibration and Wear

The effect of the proposed SPU on the steam generator tubes was evaluated based on the current design basis analysis and included the changes in the thermal-hydraulic characteristics of the secondary side of the steam generator resulting from the SPU. The effects of these changes on the fluid-elastic instability ratio and amplitudes of tube vibration due to turbulence have been addressed. In addition, the effects of the SPU on potential future tube wear have also been considered.

Description of Analyses and Evaluations

The baseline tube vibration and wear analysis results for the IP3 Model 44F RSG were used for comparison. The original vibration analysis demonstrated that the maximum fluid-elastic stability ratio for the expected tube support conditions was less than the allowable limit of 1.0. The original tube vibration analysis also determined that negligible tube responses occurred due to the vortex-shedding mechanism. The amplitudes of vibration due to turbulence were also determined to be reasonably small with maximum displacements that were determined to be on the order of [ ]a,c,e. The maximum expected tube wear that could occur over the remaining period of operation was calculated to be [ ]a,c,e.

The results of the vibration and wear analysis were modified to account for anticipated changes in secondary side operating conditions due to the SPU. The following is a summary of results.

For the expected support conditions, it was determined that straight leg stability ratios were not significantly affected. However, the stability ratio for U-bend conditions increased from [ ]a,c,e, which is still less than the allowable limit of 1.0. As a result, the analysis indicated that large amplitudes of vibration are not projected to occur due to the fluid-elastic mechanism while operating the steam generator in the SPU condition.

The maximum displacement values calculated for turbulence excitation in the original analysis were modified to account for SPU- induced changes in the operating conditions. For the most limiting tube support condition, it was determined that the turbulence-induced displacement could increase to [ ]a,c,e. Displacements of this magnitude are not sufficient to produce tube-to-tube contact. However, the potential for tube wear must be considered.

As in the original analysis, the vortex-shedding mechanism was determined not to be a significant contributor to tube vibration, which continues to be the case for operation in the post-SPU condition.

The potential for tube wear was addressed in the original analysis that addressed wear in both the straight leg and U-bend portions of the steam generator. These calculations were then updated to reflect operation of the steam generator at SPU conditions. The calculation determined that the level of tube wear that could occur would increase from [ ]a,c,e at the SPU conditions. From these calculations it can be concluded that although there may be an increase in the level of wear that could occur at the SPU operating conditions, the increased level would not be significant. Any increase in the rate of tube wear would progress over many cycles and would be observable during normal eddy current inspections, at which time remedial action could be taken.

Note that as of the 3R12 outage, no AVB wear was reported. It should be noted that there is no direct correlation of flow-induced vibration with primary-to-secondary side pressure differences. The steam generator tubes respond primarily to the conditions associated with the secondary side since the forcing functions associated with the secondary side of the steam generator dominate any other effects. Any effects of primary-to-secondary side pressure difference are inherently considered in the analysis in that the secondary side conditions are defined by the total steam generator conditions such as steam pressure, flow rates, re-circulation, etc., and include the primary-to-secondary side pressure difference.

In some model steam generators, particular consideration is given to the potential for high cycle fatigue of U-bend tubes. This phenomenon has been observed in tubes with carbon steel support plates where denting or a fixed tube support condition has been observed in the uppermost plate. However, since the IP3 steam generator TSPs are manufactured from stainless steel, there is no potential for the necessary boundary conditions (that is, denting) to occur at the uppermost support plate. Hence, high-cycle fatigue of U-bend tubes is not an issue for the IP3 Model 44F steam generators.

Conclusions

The analysis of the IP3 Model 44F RSGs indicates that significant levels of tube vibration will not occur from the fluid-elastic, vortex-shedding, or turbulent mechanisms as a result of the proposed SPU. In addition, the projected level of tube wear as a result of vibration can be expected to remain small and not result in unacceptable wear. High cycle fatigue at U-bend tubes is not an issue for concern at IP3.

5.6.7 Tube Integrity

Over a period of time, some tubes can become degraded locally under the influence of the operating loads and chemical environment in the steam generator. Degradation mechanisms observed in the first generation steam generators (for example, those using mill annealed [MA] Alloy 600 tubing) include OD stress corrosion cracking (ODSCC), primary water stress corrosion cracking (PWSCC), pitting, as well as tube wear at AVBs and TSPs due to tube vibration, and potentially at other locations such as the FDB, due to maintenance operations. The potential for these degradation mechanisms affecting the IP3 steam generators due to the SPU is discussed below.

The IP3 steam generators are Model 44F steam generators containing thermally treated Alloy 690 tubing and ASME SA-240 TSPs with broached quatrefoil (concave) holes. The first eight rows of tubes were heat treated after bending to relieve stresses. Performance of the RSGs has been exceptional with no indications of corrosion related tube degradation up to the end of cycle 12 (Reference 5).

According to laboratory testing conducted over several years by several independent organizations, Alloy 690TT is substantially more resistant to cracking than Alloy 600MA. Alloy 690TT has cracked in laboratory tests in high temperature water with characteristics similar to those of current steam generator secondary environments. Although it has not been completely immune to SCC in laboratory tests in caustic conditions, occurrences of SCC in Alloy 690TT have been relatively rare in laboratory conditions. SCC of steam generator tubing is believed to follow an Arrhenius relationship, yet no SCC has been observed in any operating steam generator with Alloy 690TT tubing.

Alloy 690TT operating experience in RSGs tubed with thermally treated Alloy 690 has confirmed its corrosion resistance. Since mid-1989, all new and replacement SGs manufactured by Westinghouse, CE, and BWI in the U.S. and most foreign vendors have used Alloy 690TT as the heat transfer tubing (and other components subject to corrosion as well). This includes 17 Westinghouse/CE PWRs and approximately 57 non-Westinghouse/CE PWRs which are operating with Alloy 690TT tubing. The Westinghouse/CE replacements have been operating for two to ten effective full-power years (EFPYs) at hot leg temperatures in the range of 596° to 620°F. Not a single incident of tube plugging due to environmental degradation has been reported in those steam generators. The highest reactor outlet temperature, 603.0°F, for the IP3 SPU is near the bottom of that range. IP3 SPU parameters used for this work are listed in Table 2.1-2 of this report. The more conservative parameters will be used for this analysis.

Secondary side steam generator chemistry has contributed to tube cracking in some units with A600MA tubing. Concentration of caustic solutions in areas of stress concentration aids the initiation of cracking. ODSCC has not been reported in any plant with Alloy 690TT tubing in approximately 15 years of operation. The presence of this condition is detectable by eddy current examination using EPRI-qualified bobbin, motorized rotating probe coil (MRPC), and array probe techniques. Thus, if any tubes in the IP3 steam generators contain a similar material condition, these tubes can be identified and effectively monitored by nondestructive examination (NDE).

In addition to enhanced tube materials of construction, the IP3 steam generators use design features that have been shown to effectively reduce the potential for SCC initiation. These include hydraulically expanded tubes in the tubesheet region, quatrefoil-broached tube hole design with stainless steel TSP material, and supplemental thermal treatment of the Row 1 through 8 U-bends following bending. Hydraulic expansion of the tubes in the tubesheet region results in reduced residual stresses compared to mechanical roll expansion and a more uniform expansion compared to explosively expanded tubes. The broached tube hole condition results in reduced potential for contaminant concentration at TSP intersections by reducing the crevice area. Supplemental thermal treatment of the row 1 through 8 U-bends following bending was performed to reduce residual stresses to near straight leg region levels. For thermally treated Alloy 690 U-bends, already highly resistant to PWSCC, this stress relief process ensures that the expected resistance to PWSCC is not diminished in the small-radius U-bends.

Potential tube degradation mechanisms due to potential localized chemistry changes at the tube surfaces after the SPU in the IP3 RSGs are ODSCC and pitting. Other degradation mechanisms are either mechanical and evaluated earlier in this report or are not relevant to IP3 RSGs. Based on laboratory and operating experience and present operating and maintenance practices at IP3 the SPU will not increase the propensity of degradation due to those mechanisms.

5.6.8 References

1. *ASME Boiler and Pressure Vessel Code* Section III, "Nuclear Vessels," 1965 Edition, Summer 1966 Addendum, The American Society of Mechanical Engineers, New York, NY.

2. *ASME Boiler and Pressure Vessel Code Section III*, "Rules for the Construction of Nuclear Power Plant Components," 1989 Edition, ASME, New York, NY.

3. NRC Regulatory Guide 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes (for comment)*, August 1976.

4. EPRI Report TR-104788-R2, *PWR Primary-to-Secondary Leak Guidelines – Revision 2*, EPRI, Palo Alto, CA, 2000.

5. Report Number SG-SGDA-02-42, *Steam Generator Degradation Assessment for Indian Point Unit 3 RFO*-12, February 2003.

Table 5.6-1

Thermal-Hydraulic Characteristics of IP3 Steam Generators

	Ref. Case	With Uprate to 3230-MWt NSSS Power			
Case	**3082 MWt**	**1a / 1b**	**2a / 2b**	**3a / 3b**	**4a / 4b**
RCS T_{avg} °F	571.5	549.0	549.0	572.0	572.0
Operating Conditions					
Power - %	100	104.8	104.8	104.8	104.8
NSSS Power - MWt	3082	3230	3230	3230	3230
Power - MWt/SG	770.5	807.5	807.5	807.5	807.5
Primary Temps. - °F					
SG T_{hot} – °F	600.8	580.3	580.3	602.5	602.5
SG T_{cold} – °F	541.9	517.0	517.0	540.7	540.7
Primary Flow - gpm	89,700	88,600	88,600	88,600	88,600
Feed Temp. - °F	427.8	390.0 / 433.6	390.0 / 433.6	390.0 / 433.6	390.0 / 433.6
Fouling - hr-ft^2-°F/Btu x 10^6	0.00011	0.00011	0.00011	0.00011	0.00011
Plugging - %	0	0	10	0	10
Operating Characteristics					a,c,e
Steam Flow/SG - 10^6 lbm/hr					
Steam Press$^{(1)}$ - psia					
Circulation Ratio					
Downcomer Velocity - ft/sec					
Total Secondary ΔP - psi					
Secondary Fluid Liquid Mass - lbm					
Secondary Fluid Vapor Mass - lbm					
Secondary Fluid Heat Content - 10^6 Btu					
Average Heat Flux - Btu/hr-ft^2					
Damping Factor - hr^{-1}					
Overall Resistance - hr-ft^2-°F/Btu					
Peak Heat Flux - Btu/ft^2-hr					
Separator Parameter					
MCO – weight %					
Operating Characteristics					
Maximum $(X/X_{DNB})^{(2)}$	NA	NA	0.9105 / NA	NA	NA

Note:

1. Table 2.1-2 steam pressures differ slightly from these values as a result of different codes used and different calculations of internal pressure drop.
2. Ratio of local quality to quality at DNB based on ATHOS runs. ATHOS analysis was performed only for Case 2a.
3. The low feedwater temperature cases are referred to as case "a" (such as Case 2a), while the high temperature cases are referred to as case "b" (such as Case 2b) for this section of the report.

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.6-2

IP3 SPU Evaluation Summary Primary and Secondary Side Components

Component	Load Condition	Stress Category	Stress (ksi)/ Fatigue - Baseline	Stress (ksi)/ Fatigue SPU	Allow (ksi)/ Fatigue	Comments
Primary Side Components						
Divider Plate	Normal/Upset	P_m+P_b+Q (1)		a,c,e	69.90	Note 4
		Fatigue			1.00	
Tubesheet & Shell Junction	Normal/Upset	P_m+P_b+Q			80.10	Note 4
		Fatigue			1.00	
Tube- to-Tubesheet Weld	Normal/Upset	P_m+P_b+Q			69.90	Note 2
		Fatigue			1.00	
Tubes	Normal/Upset	P_m+P_b+Q			79.80	
		Fatigue			1.00	
Secondary Side Components(2)						
Main Feedwater Nozzle	Normal/Upset	P_m+P_b+Q			80.10	Note 1
		Fatigue			1.00	
Secondary Manway Stud	Normal/Upset	P_m+P_b+Q			94.50	Note 1, 5
		Fatigue(3)			1.00	
Steam Nozzle	Normal/Upset					
Limiting Section		P_m+P_b+Q			80.10	Note 1
		Fatigue inside			1.00	
Insert		P_m+P_b+Q			56.07	Note 1, 3
		Fatigue			1.00	
Support Ring		P_m+P_b+Q			36.50	Note 1, 3
		Fatigue			1.00	

Note

1. Additional stress due to reduction of pressure is taken to calculate the increase in stress range for secondary side components.
2. Conservative high fatigue strength reduction factors (per NB-3228.5) are used with elastic stresses in the fatigue evaluation in place of simplified plastic analysis.
3. Exceeds $3S_m$. Simplified Elastic plastic analysis was done in the reference analysis for fatigue evaluation demonstrates code compliance
4. Exceeds $3S_m$. Plastic analysis done in the reference analysis for fatigue evaluation demonstrates code compliance.
5. $94.5 = 2.7S_m$

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.6-3 Summary of Tube Structural Limits RG 1.121 Analysis			
Location/Wear Scar Length	**Parameter**	**High T_{avg}**	**Low T_{avg}** a,c,e
Straight Leg and AVB/ 1.50 inch (Tub Rows 9-16)	t_{min} (inch)		
	Structural Limit (%)(1)		
AVB(2) / 0.9 inch Tube Rows 17-45)	t_{min} (inch)		
	Structural Limit (%)(1)		
FDB/0.75 inch	t_{min} (inch)		
	Structural Limit (%)(1)		
TSP/1.125 inch	t_{min} (inch)		
	Structural Limit (%)(1)		

Notes:

1. Structural Limit = $[(t_{nom} - t_{min}) / t_{nom}]$ x 100 percent
   t_{nom} = 0.050 in
2. The tube structural limits and minimum thickness specified for the AVB applies only for tube rows 14 and higher. For tube/AVB intersections for tube rows 1 to 13, the structural limits and minimum thickness for the FDB locations are to be used.

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.7 Pressurizer

5.7.1 Structural Analysis

The pressurizer absorbs any expansion or contraction of the primary reactor coolant due to changes in temperature and pressure and, in conjunction with the pressure control system components, keeps the Reactor Coolant System (RCS) at the desired pressure. The first function is accomplished by keeping the pressurizer approximately half-full of water and half-full of steam at normal conditions, allowing inflow to, or outflow from, the pressurizer as required via a connection to the RCS at the hot leg of one of the reactor coolant loops (RCLs). The second function is accomplished by keeping the temperature in the pressurizer at the water saturation temperature (T_{sat}) corresponding to the desired pressure. The temperature of the water and steam in the pressurizer can be raised by operating electric heaters at the bottom of the pressurizer and can be lowered by introducing relatively cool spray water into the steam space at the top of the pressurizer.

The components in the lower end of the pressurizer (such as the surge nozzle, lower head/heater well, and support skirt) are affected by pressure and surges through the surge nozzle. The components in the upper end of the pressurizer (such as the spray nozzle, safety and relief nozzle, upper head/upper shell, manway, and instrument nozzle) are affected by pressure, spray flow through the spray nozzle, and temperature differences between the pressurizer steam and the spray water.

The limiting operating conditions of the pressurizer occur when the RCS pressure is high and the RCS hot leg (T_{hot}) and cold leg (T_{cold}) temperatures are low. This maximizes the ΔT that is experienced by the pressurizer. Due to flow out of, and into, the pressurizer during various transients, the surge nozzle alternately sees water at the pressurizer temperature (T_{sat}) and water from the RCS hot leg at T_{hot}. If the RCS pressure is high (which means, correspondingly, that T_{sat} is high) and T_{hot} is low, then the surge nozzle will see maximum thermal gradients (ΔT_{hot} = temperature difference between T_{hot} and the pressurizer [surge nozzle] temperature) and, thus experience the maximum thermal stress. Likewise, the spray nozzle and upper shell temperatures alternate between steam at T_{sat} and spray water, which, for many transients, is at T_{cold}. Thus, if RCS pressure is high (T_{sat} is high) and T_{cold} is low, then the spray nozzle and upper shell will also experience the maximum thermal gradients (ΔT_{cold} = temperature difference between T_{cold} and the pressurizer [spray nozzle] temperature) and thermal stresses.

By evaluating the surge and spray nozzles, all other components are qualified. These evaluations were performed to support the IP3 SPU to address the effect of the SPU on the pressurizer. This evaluation is based on the range of NSSS operating parameters to support a NSSS power level of 3230 MWt (see Table 2.1-2 in Section 2 of this report).

The reactor vessel outlet (T_{hot}) and the reactor vessel/core inlet (T_{cold}) temperatures from Table 2.1-2 define the normal operating temperatures for the surge and spray lines to the pressurizer. The reactor coolant pressure defines the pressurizer normal operating pressure (2250 psia) and saturated temperature (653°F). The minimum values of T_{hot} and T_{cold} from all cases were used in the evaluation of the pressurizer. The NSSS design transients are also applicable to the pressurizer and were considered in the analysis.

The input parameters associated with the IP3 SPU were reviewed and compared to the design inputs considered in the current pressurizer stress report. In cases for which revised input parameters are not obviously bounded, pressurizer structural analyses and evaluations were performed, and reviewed against hand calculations using appropriate engineering assessments. Any effects to the existing design basis analysis were evaluated through a comparative analysis of the changes. This method involves a simplified engineering approach, using the existing analyses as the basis of evaluation. It uses scaling factors to assess the effect of the changes in the parameters such as the system transients, temperatures, and pressures. New stresses and revised cumulative usage factors (CUFs) are calculated, as applicable, and compared to previous results. The evaluation results show that conformance to the ASME Code-allowable limits is maintained. Since the change in the ΔT_{hot} was minimal and bounded by the original design basis calculations, no analyses were necessary for the lower shell and its key components. Only the change in the ΔT_{cold} warranted an analysis of key upper shell components such as the spray nozzle, the safety and relief nozzle, and the upper shell itself.

Conclusions

The analysis shows that the SPU will have a limited effect on the IP3 pressurizer components. Table 5.7-1 compares the fatigue usages calculated for the SPU conditions with those reported from the original design basis. The largest increase was for the spray nozzle for which the fatigue usage increased from [ ]^{a,c,e} to [ ]^{a,c,e}. The fatigue usage for the upper shell decreased significantly due to use of more realistic assumptions on spray effects than were used in the original evaluation. The results for the analyzed components, as shown on Table 5.7-1, envelop all other pressurizer components.

It is concluded that the pressurizer components meet the stress and fatigue analysis requirements of the ASME Code, Section III (Reference 1) for plant operation at the SPU conditions.

5.7.2 References

1. *ASME Boiler and Pressure Vessel Code,* Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition through Summer 1966 Addenda, The American Society of Mechanical Engineers, New York, NY.

Table 5.7-1

IP3 Pressurizer Component Fatigue Usage Comparison

Component	Revised Fatigue Usage	Previous Fatigue Usage
Spray Nozzle (node 441)	[	]a,c,e
Upper Shell (stress difference S31)		
Safety & Relief Nozzle (location 28 inside)		

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.8 Nuclear Steam Supply System Auxiliary Equipment

5.8.1 Introduction

The Nuclear Steam Supply System (NSSS) auxiliary equipment is defined as the equipment contained in the NSSS fluid systems, which are the Reactor Coolant System (RCS), the Chemical and Volume Control System (CVCS), the Residual Heat Removal System (RHRS), the Safety Injection System (SIS), the Component Cooling Water System (CCWS), the Primary Sampling System (PSS), and the Containment Spray System (CSS).

The NSSS auxiliary equipment (auxiliary tanks, heat exchangers [HXs], pumps and valves) were reviewed on a system basis for potential effects due to the revised NSSS parameters (the maximum operating temperatures, pressures, and flow rates in Table 2.1-2 in this report) and the revised design transients resulting from the Indian Point Unit 3 (IP3) stretch power uprate (SPU) conditions as discussed in Section 3 of this report. The evaluation consisted of a structural and flow capacity review of the component pressure boundaries.

5.8.2 Input Parameters and Assumptions

The NSSS parameters provided in Section 2.1 reflect the effect of the SPU on the NSSS system operating temperatures and pressures. This information was applied where applicable for evaluation of the auxiliary equipment maximum operating temperatures and pressures. Section 3.2 discusses the effect of the SPU on the NSSS auxiliary equipment design transients for the auxiliary tanks, HXs, pumps and valves subject to these transients. Section 3.1 defines the effect of the SPU on the NSSS design transients for the auxiliary system valves subject to these transients.

The evaluation of the NSSS auxiliary equipment was made relative to the technical requirements for the NSSS auxiliary equipment as originally supplied by Westinghouse.

5.8.3 Description of Analyses and Evaluations

The original design parameters, including design temperature, pressure, thermal transients, and flow rates were reviewed for the auxiliary tanks, HXs, pumps and valves. These parameters were compared to those used in the SPU, from Sections 2.1 and 3 of this report, to determine if the design parameters still enveloped those for the SPU.

5.8.3.1 Auxiliary System Tanks

None of the tanks have significant transients identified as part of the original design. From an evaluation of the data and parameters discussed in Sections 2.1 and 3, the operating temperatures and pressures for these vessels remain within the design basis for these tanks, and the SPU transients remain bounded by the original design transients.

5.8.3.2 Auxiliary System Heat Exchangers

The NSSS auxiliary HX specifications identify the applicable design transients, and the data sheets identify the design temperatures and pressures.

Based on a comparison to the NSSS parameters for the SPU, the operating temperature and pressure ranges for these vessels remain bounded by the original design parameters. Section 3 indicates that the original design transients for the auxiliary equipment bound the transients associated with the SPU. The HXs identified in the original design specifications as having transients are the regenerative, letdown, excess letdown, and RHR HXs. All of these temperatures remain bounded by the original design conditions. The RHRS HXs have been structurally evaluated for limiting operating flows during the post-loss-of-coolant-accident (post-LOCA) recirculation phase due to various pump alignments. These flow rates exceed the original design flows for the RHR HXs. The evaluation indicated the HXs were acceptable for these flows. Therefore, these flows remain valid for the SPU condition as well as the original power condition.

5.8.3.3 Auxiliary System Pumps

The NSSS auxiliary pump specifications identify the applicable design transients, and the data sheets identify the design temperatures and pressures. For the SPU conditions, the operating temperature and pressure ranges for these pumps remain bounded by the original design parameters. Section 3 indicates that the original design transients for the auxiliary equipment bound the transients associated with the SPU.

5.8.3.4 Auxiliary System Valves

The NSSS auxiliary valves specifications identify the applicable design transients, and the data sheets identify the design temperatures and pressures. For the SPU conditions, the operating temperature and pressure ranges for the valves remain bounded by the original design parameters. Section 3 indicates that the original design transients for the auxiliary equipment remain bounded for the transients associated with the SPU.

5.8.4 Acceptance Criteria and Results

If the maximum system operating temperatures, pressures, and flow rates for the SPU are bounded by the original system design conditions, then the auxiliary tanks, HXs, pumps, and valves are considered to be qualified for the SPU.

If the original design transients bound the revised SPU design transients for the auxiliary tanks, HXs, pumps, and valves, then the auxiliary tanks, HXs, pumps, and valves are considered to be qualified for the SPU.

5.8.5 Conclusions

The IP3 auxiliary tanks, HXs, pumps and valves are acceptable for the SPU conditions, since the SPU NSSS parameters are bounded by the original NSSS design parameters (for example, maximum and minimum temperatures) and the original auxiliary equipment design transients.

5.9 NSSS Components Fracture Integrity

5.9.1 Introduction

The Indian Point Unit 3 (IP3) stretch power uprate (SPU) involves changes that affect each of the primary Nuclear Steam Supply System (NSSS) components. This section addresses the effects of the SPU on the fracture integrity of the ferritic Class 1 components, specifically the reactor vessel, steam generators, and pressurizer. These are the components for which non-ductile failure must be considered, according to the requirements of the *American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code,* Section III (Reference 1).

The IP3 reactor vessel was designed to Section III of the 1965 ASME Code (Reference 2). The non-ductile failure requirements were not incorporated into the Code until Appendix G was added to the 1972 Summer Addenda and therefore, there was no Appendix G analysis of record for IP3. Consequently, a base analysis for the IP3 reactor vessel was developed as part of this task.

IP3 has the Model 44F steam generator and a Model 44F pressurizer (the Model 44F pressurizer has the same dimensions and materials as the Model D Series 84 pressurizer). Generic analyses were used for Appendix G qualification of the steam generator and pressurizer, respectively. These generic analyses were used as the base analyses for these components to assess the effect of the SPU.

5.9.2 Input Parameters and Assumptions

The key input parameters are the stresses in the various components and the fracture properties of the components. The fracture integrity evaluations for the SPU draw on the ASME Code design re-evaluations for the reactor vessel, steam generator components, and pressurizer in Sections 5.1, 5.6, and 5.7 of this report, respectively.

The stresses for the baseline reactor vessel analysis were taken from a similar reactor vessel fracture analysis. The original design transients were considered in that reactor vessel fracture analysis, and have been updated to account for the transients discussed in Section 3 of this report.

The stresses for the baseline steam generator analysis were taken from a typical Model 44F replacement steam generator (RSG) stress report. The Model D Series 84 pressurizer analysis was used as the base analysis for the IP3 pressurizer. The stresses obtained from those analyses were adjusted using scale factors previously discussed in Sections 5.6 and 5.7 of this report.

5.9.3 Description of Analyses and Evaluations

5.9.3.1 Methodology

The approach used in these evaluations is a direct application of ASME B&PV Appendix G of Section III (Reference 1). A flaw is postulated, and the crack driving force or stress intensity factor is calculated after adding a safety factor of 2.0 on the primary stresses. The applied stress intensity factor is then compared with the material fracture toughness, as characterized by the reference stress intensity factor (K_{IR}) toughness curve contained in Appendix G. The following sections detail each of these steps.

5.9.3.2 Stress Intensity Factor Calculations and Postulated Flaw Size

The maximum defect assumed in Appendix G (Reference 1) is a sharp surface defect normal to the direction of the maximum stress. The typical flaw is assumed to be semi-elliptical with an aspect ratio of 6:1 and a depth of one quarter of the vessel wall thickness.

Appendix G (Reference 1) recognizes that some regions cannot be expected to meet the requirements of a one-quarter thickness defect; it states that "smaller defect sizes may be used on an individual case basis if a smaller size of maximum postulated defect can be assured." Welding Research Bulletin 175, *PVRC Recommendations on Toughness Requirements for Ferritic Materials* (Reference 3), provides procedures for considering postulated defect sizes smaller than one quarter of the wall thickness.

The combination of examinations originally required by ASME B&PV Section III (Reference 1) (radiography and surface exams) and the volumetric examination required by Section XI (ultrasonic mapping) are capable of detecting flaws of the magnitude of those assumed for the discontinuity regions for the SPU analyses.

The stress intensity factor, K_I, was calculated for both primary and secondary stress for the limiting transients.

The value of K_I depends on:

- The geometry of the body in which the crack is postulated
- The shape and size of the crack
- The mode and the magnitude of the stress distribution at the crack surface

The general formula of K_I is

$$K_I = M_m \sigma_m + M_b \sigma_b$$

where:

M_m, M_b = the correction factors for membrane and bending stresses, respectively (depend on the depth and aspect ratio of the crack - see Figure 5.9-1)

σ_m, σ_b = membrane and bending stresses (calculated as if no crack were present)

The general formula is valid for a semi-elliptical surface flaw in both primary and secondary stress conditions.

K_I for primary and secondary stresses should be added to obtain the combined stress intensity factor. Appendix G (Reference 1) requires that a safety factor of 2 be applied to the K_I of primary stresses in normal and upset conditions. A safety factor of 1.5 is to be used for test conditions. Therefore,

$$[K_I] \text{ combined} = 2\,[K_I] \text{ primary} + [K_I] \text{ secondary}$$

for normal and upset conditions, and

$$[K_I] \text{ combined} = 1.5\,[K_I] \text{ primary} + [K_I] \text{ secondary}$$

for in-service leak and hydrostatic (ISLH) test conditions.

The methodology and the correction factors for calculation of the stress intensity factor for all analyzed regions were taken directly from Appendix G (Reference 1). The expression in Appendix G was developed for a flat plate geometry, but has also been found to be applicable to large-diameter vessels. The same expression can be used to model flaws in the nozzle corner region by setting the plate thickness equal to the nozzle corner throat thickness.

5.9.3.3 Determination of the K_{IR} Curve

The principles of linear elastic fracture mechanics (LEFM) serve as a basis for the evaluation methods of Appendix G of ASME Section III (Reference 1). The central parameter of LEFM is the crack opening mode stress intensity factor K_I. This single parameter defines the elastic stress field in the vicinity of a crack tip. K_I is dependent on the geometry of the body containing the crack, the crack size and shape, and the magnitude and distribution of the stress. A defect will grow unstably whenever K_I exceeds a critical value, K_{IC}, the fracture toughness. The fracture toughness is a material property, dependent on strain rate and temperature. It is also dependent on the metallurgical condition, that is, it changes with microstructure, neutron irradiation, and other metallurgical conditions.

For stress intensity factor rates below 2.5 ksi $\sqrt{in.}$/second (the static range), the fracture toughness is indicated by K_{Ic}, whereas for higher strain rate (the dynamic range), the critical stress intensity factor is indicated by K_{Id}. A third LEFM parameter, the arrest fracture toughness, K_{Ia}, is the value at which a fast-running crack (unstable propagation) will eventually stop. K_{Ic} values are invariably higher than K_{Id} or K_{Ia} values.

The K_{IR} curve essentially represents the lower bound static, dynamic and crack arrest critical K_I values measured as a function of temperature on specimens of SA-533 Grade B Class 1, and SA-508-1, 2, and 3 steel. No available data points for static, dynamic, or arrest tests fall below the curve for K_{IR}.

The temperature scale is defined relative to the reference nil ductility transition temperature, RT_{NDT}. The RT_{NDT}, a nonphysical constant that is related to the brittle-to-ductile fracture transition temperature, is determined by both drop weight tests and Charpy V notch impact tests.

A typical reference fracture toughness curve (K_{IR} versus temperature) is presented in Figure 5.9-2 (Figure G-2110-1 of Reference 1). To facilitate analytical calculations, the equation representing this curve can be expressed as:

$$K_{IR} = 26.78 + 1.233 \exp [0.0145 (T - RT_{NDT} + 160)]$$

Where:

K_{IR} = reference stress intensity factor, ksi $\sqrt{in.}$

T = temperature at which K_{IR} is permitted, °F

RT_{NDT} = reference nil ductility temperature, °F

A K_{IR} upper shelf of 200 ksi$\sqrt{in.}$ has been adopted for unirradiated material, and a shelf of 170 ksi$\sqrt{in.}$ has been fixed for irradiated material provided the upper shelf Charpy energy exceeds 50 ft lb. This is a generally accepted industry practice, as shown for example in EPRI Report NP-7195R (Reference 4).

Neutron irradiation adversely affects the toughness properties of the reactor vessel steel. The neutron embrittlement of the steel has been found to be a function of the copper content of the steel for given fluences.

A consequence of a decrease in the toughness properties is a shift in the fracture toughness curve to a higher temperature. Quantitatively, this shift can be assessed by determining the shift to higher temperatures of the initial reference nil ductility temperature RT_{NDT}.

The Nuclear Regulatory Commission (NRC) has also developed copper trend curves for the prediction of RT_{NDT} versus fluence. These curves are presented in Regulatory Guide (RG) 1.99, Revision 2 (Reference 5). RG 1.99 curves predict RT_{NDT} shift as a function of nickel content as well as copper content.

The fracture toughness curve, indexed to $T - RT_{NDT}$, therefore, will shift along the abscissa by a value equal to ΔRT_{NDT} for a given level of irradiation and copper and nickel content as indicated by the copper trend curves. The RT_{NDT} values at the end of life (EOL) differ sufficiently for the locations, so different reference fracture toughness curves are required.

The fluence drops drastically at a short longitudinal distance beyond the vicinity of the core assemblies as illustrated by Figure 5.9-3. For instance, the nozzles are located more than 30 inches above the top level of the core assembly. The curve in Figure 5.9-3 shows that the fluence is about 0.6 percent of the peak fluence value. This is a typical curve, and not meant to represent IP3 specifically. Thus, the irradiation effects at the nozzle areas become insignificant due to the nozzle locations relative to the core.

The upper head and lower head junctions are located still farther from the core ensuring that there will be no significant irradiation effect at those locations. Consequently, only the K_{IR} curve of the vessel beltline, which is exposed to the maximum irradiation, has been adjusted to account for the shift in RT_{NDT} resulting from irradiation.

The material properties of the reactor vessel are tabulated in Table 5.9-1 along with the initial RT_{NDT}, predicted EOL RT_{NDT}, and cross section thickness of each critical location. For the beltline region, EOL RT_{PTS} value in Table 5.1-2 of Section 5.1 is used.

5.9.3.4 Acceptance Criteria

The K_I values calculated for the affected regions of the reactor vessel, steam generator and pressurizer were compared with the corresponding material fracture toughness, K_{IR}. Protection against non-ductile failure is then assured if the K_I values are less than or equal to the K_{IR} values.

The expression used to calculate the stress intensity factor was derived for application to a flaw in a flat plate. An axisymmetrical body provides more constraint than a flat plate does. So, the stress intensities calculated by Appendix G (Reference 1) will be higher than the actual values in the reactor vessel and steam generators.

5.9.4 Analysis and Results

Reactor Vessel—The procedures of Appendix G (Reference 1) were applied to 4 critical locations in the reactor vessel: the bottom head to shell junction, the beltline region, the closure-head-to-upper-flange region, and the outlet-nozzle-to-shell-region.

The similar reactor vessel fracture evaluation was used as the baseline for assessing the effects of the SPU. The secondary stresses were adjusted to incorporate the changes described in Section 5.1 for the affected design transients. Since the pressure does not change measurably, the primary stresses are identical to the original analysis results. The reference flaw size was one quarter of the section thickness in all cases, except for the outlet nozzle where a reduced defect size of 1/5t was used. The justification for a 1/5t defect for the nozzle is based on the availability of highly reliable non-destructive inspection techniques that ensure capability of detecting such a flaw, because of the greater cross-section thickness at the nozzle-shell juncture, this flaw size is negligibly smaller than a 1/4t defect in the other areas of interest.

The combined K_I values for each design transient in Table 5.9-2 are compared with the appropriate EOL K_{IR} curve for the critical locations. Exceptions to this are the plant heatup and cooldown, and ISLH test conditions, which are controlled to be in compliance with Appendix G (Reference 1) margins through the plant *Technical Specifications.* Table 5.9-2 also shows minimum temperature during each transient for the SPU that is conservatively used for the Appendix G calculation.

The results of the analysis are plotted in Figures 5.9-4 through 5.9-7 for the bottom head to shell junction, the beltline region, the closure-head-to-upper flange region and the outlet-nozzle-to-shell region, respectively. Each transient is represented as a point corresponding to the stress intensity factor and the corresponding minimum temperature during that transient.

The fracture integrity evaluation of the IP3 reactor vessel for the SPU is summarized in Table 5.9-3. The results show that the maximum stress intensity factor for the governing transient meets the fracture toughness requirements set by ASME, Section III, Appendix G.

Steam Generator—The procedures of ASME Appendix G (Reference 1) were applied to both primary and secondary side critical components in the steam generators. The Model 44F replacement steam generator fracture mechanics analysis is applicable to the IP3 steam generators. Since hydrostatic tests are the governing transients for the critical steam generator components, those portions of the replacement Model 44F Appendix G evaluations still remain valid for the SPU. Only normal/upset conditions were affected by the SPU, therefore, only the affected normal/upset conditions were evaluated for the critical steam generator components as part of the SPU.

The Model F steam generator stress report was used as the baseline for assessing the effects of the SPU. The primary and secondary stresses were adjusted to incorporate the changes described in Section 5.6 for the affected normal/upset transients. The temperatures for the affected transients are always at least 300°F, so the shell material is always in the upper shelf range of fracture toughness, which is 200 ksi$\sqrt{\text{in.}}$, as for the reactor vessel.

The results in Table 5.9-4 show that the maximum stress intensity factor for the SPU is in all cases less than the fracture toughness, so the steam generators meet the requirements of Appendix G (Reference 1).

Pressurizer—For the pressurizer, the Model D Series 84 pressurizer fracture mechanics analysis was used as the baseline for assessing the effects of the IP3 Model 44F pressurizer for the SPU conditions. Since the change in the ΔT_{hot} was minimal and bounded by the original design basis, no analyses were necessary for the pressurizer lower shell and its key components. Only the change in the ΔT_{cold} warranted an analysis of key upper shell components such as the spray nozzle, the safety and relief nozzle, and the upper shell itself.

To take the change in the ΔT_{cold} into account, a scaling factor was derived as discussed in Section 5.7. The K_I values for the spray nozzle and the safety and relief nozzle were modified for the governing transient using this scaling factor. For the remaining pressurizer components, the existing Appendix G evaluation remains valid.

The fracture integrity evaluation of the IP3 pressurizer for the SPU is summarized in Table 5.9-5. The results show that the maximum stress intensity factors for the governing transients meet the fracture toughness requirements of Appendix G (Reference 1).

5.9.5 Conclusions

The fracture integrity evaluations completed for the SPU for the IP3 reactor vessel, steam generators, and pressurizer have shown that these components are in compliance with the fracture integrity design requirements of Appendix G (Reference 1). Such compliance was not originally required by ASME of the reactor vessel because it was manufactured to a code edition that preceded the Summer 1972 Addenda, in which Appendix G first appeared, but IP3 committed to this compliance as a condition for 10CFR50 requirements. The pressurizer and steam generators must comply, and their Appendix G analyses were modified to account for the SPU changes.

5.9.6 References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Nuclear Power Plant Components," 1998 Edition for Appendix G, The American Society of Mechanical Engineers, New York, NY.

2. *ASME Boiler and Pressure Vessel Code,* "Nuclear Vessels," 1965 Edition, The American Society of Mechanical Engineers, New York, NY.

3. Welding Research Bulletin 175, *PVRC Recommendations on Toughness Requirements for Ferritic Materials*, New York, NY, July 1973.

4. EPRI Report NP-7195R, *Flaw Evaluation Procedures: ASME Section XI*, T. U. Marstan, editor, August 1978.

5. NRC Regulatory Guide 1.99, *Radiation Embrittlement of Reactor Vessel Material*, Rev. 2, May 1988.

Table 5.9-1 IP3 Reactor Vessel Material Data				
Location	Cu-Wt (%)	Initial RT_{NDT} (°F)	Predicted End of Life RT_{NDT} (°F)	Cross-Section Thickness (inches)
Closure-Head Flange	N.A.[1]	60[2]	60	9.41
Outlet Nozzle	N.A.[1]	60[2]	60	10.75
Beltline	0.25	65	250[3]	8.63
Bottom Head Segment	N.A.[1]	15	15	8.63

Notes:

1. Not available.
2. Estimated.
3. For the beltline region, EOL RT_{PTS} value in Table 5.1-2 of Section 5.1 is used.

Table 5.9-2			
Transient Temperature – IP3			
No.	**Transient**	**Cold Leg Temperature (for beltline and bottom head) (°F)**	**Hot Leg Temperature (for outlet nozzle and top head) (°F)**
1	Heatup	[	]a,c,e
2	Cooldown		
3	Plant Loading		
4	Plant Unloading		
5	Step-Load Increase		
6	Step-Load Decrease		
7	Large Step-Load Decrease		
8	Loss of Flow		
9	Steady-State Fluctuations		
10	Loss of Load		
11	Reactor Trip		
12	Cold Hydro		
13	Hot Hydro		

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.9-3 **Fracture Integrity Evaluation Summary** **IP3 – Reactor Vessel**				
Location	**Governing Transient**	**Flaw Depth**	**Flaw Depth (in.)**	**K_I/K_{IR}**
Bottom-Head-to-Shell Junction	Loss of flow	1/4t	2.16	[ ]a,c,e
Beltline Region	Loss of flow	1/4t	2.16	
Closure-Head-to-Upper-Flange Region	Loss of flow	1/4t	2.35	
Outlet-Nozzle-to-Shell Region	Loss of load	1/5t(1)	2.15	

Note:

1. The justification for a 1/5t defect for the nozzle is based on the use of highly reliable non-destructive inspection techniques that ensure capability of detecting such a flaw.

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.9-4 Fracture Integrity Evaluation Summary for SPU Normal/Upset Transients IP3 – Steam Generators						
Location	Thickness (in.)	Min. Temp. (°F)	RT_{NDT} (°F)	Flaw Depth (in.)	K_I (ksi $\sqrt{in.}$)	K_{IR} (ksi $\sqrt{in.}$)
Tubesheet and Shell Junction	5.22	[	]a,c,e	0.6525(1)	[ ]a,c,e	200
Secondary Manway	3.51			0.8775		200
Steam Outlet Nozzle	1.35			0.945(1)		200
Feedwater Nozzle	6.53			0.7256(1)		200

Note:

1. The justification for a smaller defect is based on the use of highly reliable non-destructive inspection techniques that ensure capability of detecting such a flaw.

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.9-5 Fracture Integrity Evaluation Summary IP3 – Pressurizer			
Location	**Governing Transient**	**Flaw Depth**	**K_I/K_{IR}**
Spray Nozzle (corner region)	[ ]a,c,e	1/4t	[ ]a,c,e
Safety & Relief Nozzle (corner)		0.50	
Upper Shell		0.15	
Lower Head/Support Skirt		1/4t	
Support Lug		1/4t	
Manway (knuckle region)		1/4t	
Valve Support Bracket		0.13	
Surge Nozzle (corner region)		1.42	

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

a,c,e

Figure 5.9-1

M_m and M_b versus $\sqrt{\text{Thickness}}$ Curves

a,c,e

Figure 5.9-2

K_{IR} Reference Stress Intensity Factor Curve

a,c,e

Figure 5.9-3

Longitudinal Distance vs. Multiplying Factor for Peak Fluence

a,c,e

Figure 5.9-4

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Bottom-Head-to-Shell Junction (RT_{NDT} = +15°F)

a,c,e

[ ]

Figure 5.9-5

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Beltline Region (RT_{NDT} = +250°F)

a,c,e

Figure 5.9-6

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Closure-Head-to-Upper-Flange Region (RT_{NDT} = +60°F)

a,c,e

Figure 5.9-7

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Outlet Nozzle-to-Shell Region (RT_{NDT} = +60°F)

5.10 Reactor Coolant System Potential Material Degradation Assessment

This section summarizes the evaluations and results of an assessment of the potential materials degradation issues arising from the effects of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) on the performance of primary component materials.

The primary concern from the proposed SPU is the potential effect of changes in the Reactor Coolant System (RCS) chemistry (impurities) and pH conditions and the SPU service temperatures on the integrity of primary component materials during service. These concerns include general corrosion (wastage) and stress corrosion cracking (SCC) of system materials, fuels corrosion, and primary water stress corrosion cracking (PWSCC) of nickel base alloys. These issues are discussed in the following subsections.

5.10.1 Proposed SPU Service Conditions

A review of the SPU design documents indicates that the following changes in the RCS chemistry and service conditions will occur during operations after the SPU implementation:

- The reactor coolant Li/B program is coordinated such that a pH value of 7.04 is maintained during the fuel cycle with a maximum lithium level of 3.5 ppm.
- The maximum increase in the upper reactor vessel head penetration (RVHP) temperature due to the SPU is estimated at 5.3°F (Table 5.10-1).
- The maximum increase in the hot-leg nozzle temperature due to the SPU is estimated at 2.2°F (Table 5.10-1).

5.10.2 Materials Assessment

The effect of the proposed service conditions on the performance of RCS materials is considered below:

Austenitic Stainless Steels

The two degradation mechanisms that are operative in austenitic stainless steels are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Susceptible materials, sensitized microstructure, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC. The chemistry changes resulting from the SPU do not involve introduction of any of these contributors so that no effect on material degradation is expected in the stainless steel components as a result of the SPU.

Fuel-Cladding Corrosion Effects

An examination of the proposed lithium, boron, and pH management program showed that the program adequately meets the proposed Electric Power Research Institute (EPRI) chemistry guidelines (Reference 1). Since these guide lines are specifically designed to prevent fuel-cladding corrosion effects such as fuel deposit build-up and Alloy 600 PWSCC, there will be no adverse effect on fuel cladding corrosion. Experience with operating plants as well as with the guidelines provided by EPRI (Reference 1) suggest that increasing initial Li concentrations of up to 3.5 ppm with controlled boron concentrations to maintain pH values ranging from 6.9 to 7.4 has not produced any undesirable material integrity issues and is considered acceptable. IP3 plans to maintain Lithium levels at 3.5 ppm or less. Therefore, there will be no adverse effects from this aspect of the SPU.

Alloy 600/82/182 Components

The most significant factor that influences the PWSCC of Alloy 600/82/182 components is the service temperature. The two most significant Alloy 600/82/182 components that are bounding to the PWSCC susceptibility are the reactor vessel head penetrations (RVHPs) and the hot-leg nozzle welds. These are considered below.

The Alloy 600 PWSCC susceptibility is a thermally activated process. The PWSCC susceptibility (S) (Reference 2) is given by:

$$S = A(Fyk)^4 \exp(-Q/RT)$$

where A is the material constant

$(Fyk)^4$ is the stress factor

Fy being the yield strength

and k the residual stress factor

Q is the activation energy of the PWSCC process (~50,000 cals/mole)

R the gas constant 1.103 cal/°R

T the temperature in °R

For the current situation, since the only variable due to uprating is the component service temperature, the susceptibility (S) can be expressed as:

$$S = B \exp(-Q/RT), \text{ B being a constant}$$

The change in the PWSCC susceptibility (ΔS) due to a change in the service temperature (ΔT) can be obtained by taking a differential and is given by:

$$\Delta S = B \exp(-Q/RT)\,(Q/RT^2)\,\Delta T$$

$$\text{or } \Delta S/S = (Q/RT^2)\,\Delta T$$

This change will only be experienced going forward in time. As such, the total susceptibility to PWSCC will be related to the integrated time-temperature history. A methodology has been proposed by the NRC in Order EA-03-009 (Reference 3) for calculating the integrated effect of changing times and temperatures and normalizing the data to a common reference temperature. This methodology calculates a term called Effective Degradation Years (EDY) to account for temperature changes during the current operating lifetime.

5.10.3 Service Temperature Data

A summary of service temperatures at component locations of interest for various design basis cases is provided in Table 5.10-1. The first two lines of Table 5.10-1 provide the calculated upper head temperature and hot-leg nozzle temperatures for a core power level of 3067 MWt. The last two lines of Table 5.10-1 provide the calculated upper head temperature and hot-leg nozzle temperatures for the SPU conditions and cases discussed in Section 2 of this report. See the notes on Table 5.10-1 for details of the cases for each temperature value. The maximum increases in service temperatures (ΔT) at the bounding RVHP and hot-leg outlet nozzle weld locations are provided in Table 5.10-1.

5.10.4 Change in the PWSCC Susceptibility of RVHPs

The industry experience over the past decade showed that the PWSCC susceptibility of the Alloy 600/82/182 outermost circle RVHPs is considered bounding to other Alloy 600 primary component locations due to the presence of high residual stresses and service temperatures at those penetration locations. The RV upper head best-estimate mean fluid maximum service temperature is considered to be the RVHP temperature for the purpose of the current evaluation.

The maximum change in the PWSCC susceptibility value (ΔS) of the highest susceptible (outer circle) penetration was assessed from the maximum change in the penetration temperature (ΔT_{max}) due to the SPU. This value was established from the data in Table 5.10-1 to be 5.3°F or 5.3°R.

From the equation above:

$$\Delta S/S = Q/(RT^2)\,(\Delta T°R) = (50000/(1.103*1052.47^2)*5.3 = 22\%$$

$\Delta S/S$ being the fractional change in the PWSCC susceptibility, and ΔT, the change in the service temperature in units of Rankine.

On this basis, an increase in the PWSCC susceptibility of 22 percent was estimated for the RVHP as a result of the SPU. This change would be recognized going forward in time. The relative increased risk going forward can be evaluated by integrating the time-temperature history and comparing that value to an integrated history if no change were made.

5.10.5 Change in the PWSCC Susceptibility of Alloy 82/182 Hot-Leg Nozzle Weld

The maximum change in the hot-leg nozzle weld PWSCC susceptibility due to the SPU was assessed from the data in Table 5.10-1 to be 2.2°F (2.2°R).

The change in the PWSCC susceptibility value (ΔS) of the highest susceptible hot-leg nozzle weld was assessed from the change in the RV outlet nozzle temperature ΔT due to uprating, from the above equation:

$$\Delta S/S = Q/(RT^2)\,(\Delta T°R) = (50000/(1.103*1062.67^2)(2.2) = 9\%$$

$\Delta S/S$ being the fractional change in the PWSCC susceptibility, and ΔT, the change in the service temperature in units of Rankine.

On this basis, an increase in the PWSCC susceptibility of 9 percent was estimated for the RV hot-leg nozzle weld as a result of the SPU. This change would be recognized going forward in time. The relative increased risk going forward can be evaluated by integrating the time-temperature history and comparing that value to an integrated history if no change were made.

5.10.6 Conclusions

An assessment of the potential materials degradation issues resulting from the SPU at IP3 concluded that:

- No appreciable material degradation issues were identified with the internal and core support materials due to the SPU at IP3. The lithium concentration will be limited to 3.5 ppm.
- The PWSCC susceptibility of the highest susceptible Alloy 600 control rod drive mechanism (CRDM) penetration was calculated to increase by an estimated 22 percent going forward in time. The rate of damage accumulation leading to PWSCC initiation will slowly increase after the change is made.
- The PWSCC susceptibility of the Alloy 82/182 hot-leg nozzle weld was calculated to increase by 9 percent due to the SPU going forward in time.

The increase in PWSCC susceptibilities of Alloy 600 RVHP and hot-leg nozzle weld locations (22 and 9 percent) indicated above is not considered significant since the absolute susceptibility of these locations is estimated to be very low ($\sim 10^{-11}$).

5.10.7 References

1. EPRI TR-1002884, *Pressurized Water Reactor Primary Water Chemistry Guidelines*, Rev. 5, September 2003.

2. *Methodologies to Assess PWSCC Susceptibility of Primary Component Alloy 600 Locations in PWRs*, Proceedings of the 6th International Symposium on Environmental Degradation of Materials, G. V. Rao, NACE, August, 1993.

3. NRC Order EA-03-009 – Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors, Feb. 2003.

Table 5.10-1 Summary of Change in the Vessel Upper Head and Hot Leg Nozzle Service Temperatures due to the SPU				
Core Power Level (MWt)	**Location**	**Lower-Bound Temperature (°F)**	**Upper-Bound Temperature (°F)**	**Maximum Increase in Temperature (ΔT°F)(2)**
3067	RV Upper Head	NA(1)	587.6	[redacted]
3216	RV Upper Head	570.2	592.9	[redacted]
Temperature Change		-17.4(2)	5.3°F	5.3°F
3067	Hot-Leg Nozzle	NA(1)	600.8	[redacted]
3216	Hot-Leg Nozzle	580.8	603.0	[redacted]
Temperature Change		-20(2)	2.2°F	2.2°F

Notes:

1. Lower bound temperatures and maximum increases in temperature are not applicable (NA) at 3067 MWt. (IP3 did not have a T_{avg} design range prior to the SPU.)
2. The lower bound SPU temperatures relative to the pre-SPU design condition represent a decrease in susceptibility.

6.0 SAFETY ANALYSIS

The Indian Point Unit 3 (IP3) stretch power uprate (SPU) includes safety analyses for the *Updated Final Safety Analysis Report* (UFSAR) transients and accidents at SPU conditions. This section includes the evaluation of initial condition uncertainties at SPU conditions, which are provided as input to the safety analyses. The results of the safety analyses and setpoint calculations identified whether any changes are required to the Reactor Trip System (RTS)/ Engineered Safety Feature Actuation System (ESFAS) setpoints. The RTS/ESFAS setpoint calculations are addressed in Section 6.10 of this report.

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

- Loss-of-coolant-accidents (LOCAs)
- Non-LOCA
- Steam generator tube rupture (SGTR) transients
- LOCA containment integrity
- Main steamline break (MSLB) inside and outside containment
- LOCA hydraulic forces
- Anticipated transients without scram (ATWS)
- Natural circulation cooldown capability
- Radiological assessments

The analyses and evaluations presented in this section support operation of IP3 at an uprated core power of 3216 MWt.

6.1 Initial Condition Uncertainties

6.1.1 Introduction

Initial condition uncertainties are conservative steady-state instrumentation measurement uncertainties that are applied to nominal parameter values to obtain conservative initial conditions for use in safety analyses. The initial condition uncertainties were recalculated at SPU conditions for use in the Indian Point Unit 3 (IP3) stretch power uprate (SPU) analyses and evaluations to assess the acceptability of the safety analyses at SPU conditions. The initial condition uncertainties for the SPU conditions were provided as input to the loss-of-coolant accident (LOCA) analysis (Section 6.2 of this report), non-LOCA analysis (Section 6.3), steam generator tube rupture (SGTR) analysis (Section 6.4), LOCA containment integrity analysis (Section 6.5), main steamline break (MSLB) inside and outside containment analysis (Section 6.6), LOCA hydraulic forces analysis (Section 6.7), and core thermal-hydraulic design analysis (Section 7.2).

6.1.2 Input Parameters and Assumptions

The uncertainty calculations for the IP3 SPU were performed for the SPU operating conditions based on the plant-specific instrumentation and plant calibration and calorimetric procedures.

6.1.3 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, that 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 IP3 SPU is defined in WCAP-16099-P (Reference 1).

Initial condition uncertainties were evaluated and recalculated as appropriate for the following six parameters that are explicitly modeled in the IP3 safety analyses:

- Pressurizer Pressure Control - Automatic pressurizer pressure control system (not affected by the SPU)
- RCS T_{avg} Control - Automatic reactor temperature control system
- Reactor Power Measurement - Daily calorimetric power measurement (rated thermal power [RTP])

- Reactor Coolant System (RCS) Total Flow Measurement – Loop RCS flow measurements based on a normalization to the once-per-fuel-cycle calorimetric RCS flow measurement to verify analysis flow assumptions

- Steam Generator Water Level Control - Automatic steam generator water level control system

- Pressurizer Water Level Control - Automatic pressurizer water level control system

To support the start of analyses and/or evaluations for safety analyses early in the IP3 SPU, preliminary initial condition uncertainties for power uprate were provided as input to safety analyses and evaluations. The initial condition uncertainties for the SPU were then calculated and finalized at a later time during the project, and confirmed to be bounded by the preliminary values. Therefore, although various safety analyses and evaluations may incorporate the preliminary initial condition uncertainties, those allowances are bounding compared to the calculated final values.

6.1.4 Acceptance Criteria and Results

The acceptance criterion for the initial condition uncertainties is that the final calculated values must be bounded by the allowances incorporated in the safety analyses.

The results of the initial condition uncertainty analysis for the IP3 SPU are summarized in Table 6.1-1 along with the allowances incorporated in the safety analyses. Pressurizer pressure control and pressurizer water level control are included for completeness, although pressurizer pressure control was not affected and pressurizer water level control was minimally affected by the IP3 SPU. With the exception of RCS T_{avg} control, this table demonstrates that the safety analyses incorporate uncertainties that are equal to or greater than the final calculated values. Safety analyses that use the RCS T_{avg} control uncertainty were modified to account for the larger final calculated value. The uncertainty calculations for steam generator water level control included the resolution of the generic steam generator level uncertainty issues (References 2 through 5), which are unrelated to the power uprate.

6.1.5 Conclusions

Preliminary initial condition uncertainties were determined for the IP3 SPU conditions and were provided as input to the safety analyses and evaluations. Final initial condition uncertainties were calculated and either confirmed to be bounded by the preliminary initial condition uncertainties, or the affected safety analyses were modified to account for the more conservative final initial condition uncertainty value.

6.1.6 References

1. WCAP-16099-P, *Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology Indian Point Unit 3 (Power Uprate to 3216 MWt – Core Power)*, Rev. 0.

2. NSAL-02-03, *Steam Generator Mid-deck Plate Pressure Loss Issue*, Rev. 1, April 2002.

3. NSAL-02-04, *Maximum Reliable Indicated Steam Generator Water Level*, Rev. 0, February 2002.

4. NSAL-02-05, *Steam Generator Water Level Control System Uncertainty Issue*, Rev. 1, April 2002.

5. NSAL-03-09, *Steam Generator Water Level Uncertainties*, Rev. 0, September 2003.

Table 6.1-1 IP3 SPU Summary of Initial Condition Uncertainties		
Parameter	Limiting Analysis Initial Condition Uncertainties(1)	Calculated Final Initial Condition Uncertainties(1)
Pressurizer Pressure Control(2)	±60.0 psi (random)	a,c,e
RCS T_{avg} Control(5)	±6.0°F (random) -1.0°F (bias)	
Reactor Power Measurement	±2.0% RTP (random)	
RCS Total Flow Measurement	±2.9% Flow (random)	
Steam Generator Water Level Control	±10.0% span (random)	
Pressurizer Water Level Control High(2)	±8.5% span (random)	

Notes:

1. A negative bias means the channel indicates lower than actual, and a positive bias means the channel indicates higher than actual.
2. Parameter included, although uncertainty not affected by the SPU.
3. Based on use of Caldon leading edge flow meter (LEFM).
4. Based on use of feedwater venturis.
5. The following analyses have accounted for the more conservative RCS T_{avg} control calculated final initial condition uncertainty:
   - Large-break LOCA (LBLOCA) (best-estimate) analysis
   - LBLOCA hydraulic forces analysis
   - Small-break LOCA (SBLOCA) analysis
   - Non-LOCA analyses
   - Steam-line break inside and outside containment M&E releases analyses
   - Thermal-hydraulic analysis
   - Containment integrity for LBLOCA analysis
   - Pressurizer pressure control sizing analysis
   - Radiological analysis

Backeted [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report

6.2 Loss-of-Coolant Transients

6.2.1 Best-Estimate Large-Break Loss-of-Coolant-Accident

6.2.1.1 Introduction

Westinghouse has obtained generic NRC approval of its topical report describing best-estimate large-break loss-of-coolant accident (BELBLOCA) methodology. NRC approval of the methodology is documented in the NRC *Safety Evaluation Report* (SER) appended to the topical report (Reference 1). Plant-specific analysis for Indian Point Unit 3 (IP3) was previously performed using the approved methodology.

A BELOCA re-analysis has been performed at the analyzed stretch power uprate (SPU) core power conditions (3216 MWt). The values of major plant parameters assumed in the BELOCA analysis will be documented in the respective sections of the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 2). These and other UFSAR changes resulting from approval of this *Licensing Amendment Report* (LAR) will be made in accordance with 10CFR50.71(e) (Reference 3).

Both Entergy and its analysis vendor (Westinghouse) have ongoing processes (updated *Technical Specifications*, plant operating ranges table in the UFSAR, core operating limits report), which assure that the values and ranges of the BELBLOCA analysis inputs for peak cladding temperature (PCT)-sensitive parameters bound the values and ranges of the as-operated plant for those parameters.

6.2.1.2 Acceptance Criteria

The criteria for acceptability for LOCAs are found in 10CFR50.46(b) (Reference 4). The criteria require that there is a high probability that:

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

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

3. Maximum Hydrogen Generation: 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. Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. Long-Term Cooling: 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.

6.2.1.3 Technical Analysis

The BELBLOCA re-analysis has been performed for IP3 using the methodology contained in WCAP-12945-P-A (Reference 1). All plant-specific parameters used in the analysis are bounded by the models and correlations contained in the generic methodology. Therefore, the IP3 re-analysis conforms to 10CFR50.46 (Reference 4) and Section II of Appendix K (Reference 5), and meets the intent of Regulatory Guide (RG) 1.157 (Reference 6). The conclusions of the re-analysis are that there is a high level of probability that:

- The calculated maximum fuel element cladding temperature (peak cladding temperature) will not exceed 2200°F.

- The calculated total oxidation of the cladding (maximum cladding oxidation) will not exceed 0.17 times the total cladding thickness before oxidation.

- The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam (maximum hydrogen generation) will nowhere 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.

- The calculated changes in core geometry are such that the core remains amenable to cooling.

- After successful initial operation of the Emergency Core Cooling System (ECCS), the core temperature will be maintained at an acceptably low value and decay heat will be removed for the extended period of time required by the long-lived radioactivity remaining in the core. The post-LOCA long-term cooling aspects are discussed in subsection 6.2.4.

Table 6.2-1 presents the 95th percentile peak clad temperature (PCT), maximum cladding oxidation, maximum hydrogen generation, and cooling results for IP3.

Therefore, Entergy has concluded that the BELBLOCA analysis for IP3 at the SPU conditions would not adversely affect the health and safety of the public.

6.2.2 Small-Break Loss-of-Coolant Accident

6.2.2.1 Introduction

A small-break loss-of-coolant accident (SBLOCA) analysis was performed to support the SPU for IP3. The analysis was performed to demonstrate conformance with the 10CFR50.46 requirements (Reference 4) for the conditions associated with the SPU and to explicitly include modeling of items for which the Analysis of Record (AOR) had PCT assessments applied. The approved Westinghouse SBLOCA Evaluation Model (EM) was used for this analysis (References 7 and 8). The SBLOCA EM update that has been approved by the NRC (References 7 and 8) has been used in this analysis, including the COSI condensation model and safety injection (SI) in the broken loop (Reference 9).

6.2.2.2 Input Assumptions and Initial Conditions

6.2.2.2.1 Assumptions

All of the assumptions required by Appendix K to 10CFR50 (Reference 5) have been made in the IP3 SBLOCA analysis. This analysis returns to the assumption of a 2-percent power uncertainty by assuming 102 percent of full power as the initial condition for the SBLOCA. Other Appendix K assumptions include, but are not limited to, all peaking factors simultaneously at their most limiting values, Baker-Just zirconium-water reaction rate, 120 percent of 1971 American Nuclear Society (ANS) infinite life decay heat, and Moody break flow during periods when two-phase flow is calculated to occur at the break.

Among the major assumptions inherent in the Westinghouse Appendix K SBLOCA EM are:

- Break area is <1 ft^2.
- SBLOCA initiates at hot full power (HFP) (Mode 1).
- All rod cluster control assemblies (RCCAs), except the single most reactive, insert following reactor trip.

- Loss-of-offsite power (LOOP) assumed at reactor trip time results in the following assumptions:
  - Loss of one emergency diesel generator (EDG) and subsequent loss of one train of pumped ECCS
  - Reactor coolant pump (RCP) trip and coastdown
  - Main steam line isolation (no steam dump capability)
- Standard four-loop ECCS spilling assumptions

A spectrum of 3 break sizes, including diameters of 2, 3, and 4 inches, was analyzed.

6.2.2.3 Description of Methodology/Analysis

6.2.2.3.1 Description of SBLOCA Engineering Methodology and Codes

The small-break analysis was performed with the Westinghouse ECCS EM using NOTRUMP (References 7 and 8), including changes to the model and methodology as described in Reference 9. The NOTRUMP EM includes the following computer codes:

NOTRUMP: Thermal-hydraulic response of Reactor Coolant System (RCS) during transient

SBLOCTA: Fuel rod/cladding heat-up during transient

6.2.2.3.2 Description of Analysis Performed for SBLOCA

The methodology first calculated the system thermal-hydraulic response to the SBLOCA event using the NOTRUMP code. These results are then analyzed for their effect on the hot rod heat up using the SBLOCTA code to demonstrate that the PCT, cladding oxidation, and hydrogen generation are below their limiting values as defined by 10CFR50.46 (Reference 4).

6.2.2.3.3 Limiting SBLOCA Sequence

The analysis consists of a break spectrum using the approved methodology as documented in References 7 and 8 and extended in Reference 9. For the IP3 SBLOCA analysis, a three-break spectrum (2-, 3-, and 4-inch) has been analyzed to confirm that the 3-inch break is limiting. The results are presented in Tables 6.2-2 and 6.2-3.

6.2.2.4 Design Basis Acceptance Criteria

The criteria for acceptability for LOCAs are found in 10CFR50.46(b) (Reference 4) and are quoted below:

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

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

3. Maximum Hydrogen Generation: 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. Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. Long-Term Cooling: 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.

6.2.2.5 Results and Conclusions

6.2.2.5.1 Description of Limiting 3-Inch Break Case

For the limiting 3-inch break, the primary side pressure begins a rapid drop at the time of break initiation (Figure 6.2-1). A reactor trip signal is generated at 22.8 seconds, followed by a SI signal at 30.2 seconds. This primary side depressurization is checked when the primary side saturation temperature reaches the secondary side saturation temperature, since the steam generators provide the predominant energy release path during this portion of the transient. When the loop seal in the broken loop clears at approximately 582 seconds, a vapor vent path is created between the top of the core and the break in the cold leg.

At break initiation, the core mixture level (Figure 6.2-2) drops rapidly until it reaches the elevation at the top of the hot legs. The rate of core level draining is then slowed as vapor is now allowed to enter the hot legs or the inner vessel due to the loop seal clearing. When the core mixture level decreases below the bottom of the hot legs, the mixture level again decreases until loop seal clearing occurs (Figure 6.2-2). After loop seal clearing, the core and downcomer come into a manometric balance as the downcomer level falls in response to the adjacent cold legs draining.

The core mixture level continues to decrease until the top of the core uncovers at 765 seconds, leading to the start of clad heat up. As illustrated in Figure 6.2-3, the SI flow rate continues to increase as the RCS pressure decreases (Figure 6.2-1). The SI replenishes the core level, which results in a reversal in the clad heat up transient. The PCT of 1543°F occurs at 1954 seconds (Figure 6.2-4), followed by a steady increase in the core mixture level. The accumulators inject at 1688 seconds. The transient core exit steam flow has been presented in Figure 6.2-5. The results of the 3-inch break case are presented in Tables 6.2-2 and 6.2-3.

6.2.2.5.2 Non-Limiting Results

The results of the 2- and 4-inch break cases are presented in Tables 6.2-2 and 6.2-3. Figures 6.2-6 through 6.2-11 pertain to the 2-inch and 4-inch break cases. The figures provided for the non-limiting cases are:

- Figure 6.2-6 – 2-Inch Break, Pressurizer Pressure
- Figure 6.2-7 – 2-Inch Break, Core Mixture Level
- Figure 6.2-8 – 2-Inch Break, PCT at PCT Elevation (11.5 ft)
- Figure 6.2-9 – 4-Inch Break, Pressurizer Pressure
- Figure 6.2-10 – 4-Inch Break, Core Mixture Level
- Figure 6.2-11 – 4-Inch Break, PCT at PCT Elevation (11.25 ft)

6.2.2.5.3 10CFR50.46 PCT Report Item Incorporation

As a result of this analysis, all items from the IP3 10CFR50.46 (Reference 4) PCT report are eliminated. This was accomplished by using the latest version of the NOTRUMP EM codes and incorporating each of the other miscellaneous items into the analysis.

6.2.2.5.4 Maximum Local and Core-Wide Oxidation

All cases meet the 10CFR50.46 requirements of maximum local and core-wide oxidation. The local oxidation of the cladding, does not exceed 17 percent, and the calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam does not exceed 1 percent.

6.2.2.5.5 Conclusions

The results of the analysis show that the acceptance criteria discussed in subsection 6.2.2.4 of this document for the SBLOCA have been met. The limiting PCT for IP3 will be reported as 1543°F, which occurs for the 3-inch break case. Local oxidation of the cladding is less than 17 percent, the core-wide oxidation is less than 1.0 percent and the core geometry remains amenable to cooling. The post-LOCA long-term cooling aspects are discussed in subsection 6.2.4. Results for the 3-inch limiting break case are shown in Figures 6.2-1 through 6.2-5.

6.2.3 Hot Leg Switchover

6.2.3.1 Introduction

A post-LOCA hot leg switchover (HLSO) time is calculated to support emergency operating procedures (EOPs) that require a realignment of the recirculation SI flowpath from the cold legs to the hot legs. This realignment to the hot legs precludes boron precipitation in the reactor vessel following an LBLOCA. At issue are cold-leg breaks where injected SI water boils off due to decay heat, leaving behind boric acid. The concern is the possibility that eventually the boric acid solution in the vessel may reach the boron precipitation point. The Westinghouse ECCS evaluation model relies on the preclusion of boron precipitation as one criterion for ensuring core coolable geometry.

6.2.3.2 Input Parameters and Assumptions

The IP3 HLSO calculation model is based on the following assumptions:

- A boric acid concentration level is computed over time for a core-region mixing volume. Other than the steam exiting through the hot legs and the corresponding makeup SI entering through the lower plenum, there are no other assumed flow paths in or out of the mixing volume. All boric acid entering this mixing volume remains in this mixing volume prior to initiation of hot-leg recirculation. The water/boric acid solution is well mixed in the mixing volume region. The water/boric acid solution in the vessel is assumed to be at atmospheric conditions, at a temperature of 212°F. The collapsed mixture level of the core/upper plenum region is at the bottom of the hot-leg flow area at the reactor vessel. This level is the top of the mixing volume. The bottom of the mixing volume is at the level of the top of the lower core plate. The lower plenum volume, and barrel-baffle region volume are not included in the mixing volume.

- The boric acid concentration limit is the experimentally determined boric acid saturation concentration with a 4 weight-percent uncertainty factor. There is no allowance for increase in boric acid solubility due to other solutes such as sodium hydroxide. The calculation neglects any elevation of boiling temperature due to concentration of boric acid in the core or due to backpressure from containment.

- The decay heat generation rate is based on the 1971 ANS Standard (Reference 10) for infinite operating time plus 20-percent margin. The decay heat generation includes a core power multiplier to address instrumentation uncertainty as identified by Section I.A of Appendix K (Reference 5).

- The boron concentration of the make-up SI water during recirculation is a calculated sump mixed mean boron concentration. The calculation of the sump mixed mean boron concentration assumes maximum mass and maximum boron concentrations for significant boron sources and minimum mass and maximum boron concentrations for significant dilution sources.

- Once realigned to hot-leg recirculation, the minimum recirculation flows for the hot legs, cold legs, or simultaneous hot- and cold-leg recirculation are confirmed to be sufficient to provide core cooling and preclude boron precipitation.

The methodology described above is consistent with, or otherwise conservative with respect to, the methodology described in Letter CLC-NS-309 (Reference 11).

6.2.3.3 Description of Analyses and Evaluations

The major inputs to the HLSO time calculation include the core power assumptions and boron concentrations and water volume/masses for significant contributors to the containment sump. Since the increase in core power to 3216 MWt effects decay heat, recalculation of the HLSO time and hot-leg recirculation minimum required flows are required. An increase in core power will reduce the HLSO time and increase the hot-leg recirculation minimum required flows.

For the SPU, a new HLSO time was calculated using the input parameters and assumptions described in the previous section, including decay heat based on the 1971 ANS Standard (Reference 10) for infinite operation with 20-percent margin. All inputs to the calculation were reviewed and confirmed to be appropriate for plant operation at the SPU conditions. The uprating calculations used the uprated core power of 3216 MWt with a 1.02-calorimetric uncertainty multiplier to address instrumentation uncertainty.

A revised set of hot-leg recirculation minimum required flows were calculated at the SPU conditions and new HLSO time.

6.2.3.4 Acceptance Criteria and Results

There are no specific acceptance criteria on the new hot-leg switchover time for the SPU conditions as long as the UFSAR (Reference 2) and EOPs are revised appropriately. The available flows at hot-leg switchover time are acceptable if they are shown to be sufficient to provide core cooling.

At the SPU conditions, a new HLSO time of 6.79 hours was calculated. The time of 6.79 hours was rounded down to 6.5 hours for added conservatism. The minimum hot-leg recirculation flows at a HLSO time of 6.5 hours and a power level of 3216 MWt are sufficient to preclude boron from precipitating in the vessel and to ensure adequate core cooling is maintained. As noted in Section 6.12 of this report, the EOPs will be revised to reflect the SPU HLSO time.

6.2.3.5 Conclusions

A HLSO time of 6.5 hours will preclude boron precipitation for post-LOCA scenarios for the SPU conditions. The available ECCS flows at hot-leg switchover were shown to be sufficient to provide core cooling and preclude boron from precipitating in the core.

6.2.4 Post-LOCA Subcriticality and Long-Term Core Cooling

6.2.4.1 Introduction

The post-LOCA subcriticality calculations support evaluations that demonstrate that the core will remain subcritical upon entering the sump recirculation phase of ECCS injection. During the sump recirculation phase, SI flow is drawn from the containment sump following switchover from the refueling water storage tank (RWST). To show that the sump water has sufficient boron concentration, the sump-mixed mean boron concentration is calculated. The mixed-mean boron concentration of the sump water is a function of the various water and boron contributors to the sump prior to start of sump recirculation. The boron concentration of the sump water must be sufficient to keep the core subcritical. The sump mixed-mean boron concentration calculations are used to develop a post-LOCA subcriticality boron limit curve that is confirmed on a cycle-specific basis as part of the *Westinghouse Reload Safety Evaluation Methodology* (Reference 12). Long-term core cooling also requires adequate ECCS flow to provide core cooling during the cold-leg recirculation period.

6.2.4.2 Input Parameters and Assumptions

The sump-mixed mean boron concentration calculation model is based on the following assumptions:

- Boron is mixed uniformly in the sump. The post-LOCA sump inventory is made up of constituents that are equally likely to return to the containment sump, that is, selective holdup in containment is neglected.

- The calculation of the sump mixed-mean boron concentration assumes minimum mass and minimum boron concentrations for significant boron sources, and maximum mass and minimum boron concentration for significant dilution sources.

- The sump mixed-mean boron concentration is calculated as a function of the pre-trip RCS conditions.

The Westinghouse licensing position for satisfying the requirements of 10CFR50.46 (Reference 4) Paragraph (b) Item (5), "Long-Term Cooling," is documented in WCAP-8339 (Reference 13). The Westinghouse position is that the core will remain subcritical post-LOCA by borated water from various injected ECCS water sources. To provide subcriticality when entering sump recirculation, the borated ECCS water provided by the accumulators and RWST must have a sufficiently high boron concentration that, when mixed with other sources of borated and non-borated water, the core will remain subcritical. Consistent with the position in WCAP-8339 (Reference 13), control rods are assumed to be withdrawn from the core.

Long-term core cooling also requires adequate ECCS flow to provide core cooling. For IP3, the confirmation of adequate ECCS flow during the cold-leg recirculation period is based on the following assumptions:

- The current SBLOCA analysis methodology explicitly models ECCS flow enthalpy changes during the switchover from cold-leg injection to cold-leg recirculation.

- The long-term core cooling methodology assumes that large-break ECCS flows are not adversely affected by the switchover from cold-leg injection to cold-leg recirculation.

6.2.4.3 Description of Analyses and Evaluations

Although core power level is not a direct input in the sump mixed-mean boron concentration calculation, the T_{avg} range associated with power uprate conditions will have a minor effect on the RCS fluid masses used in the calculation. Furthermore all of the inputs used in the calculation were reviewed to confirm consistency with the *Technical Specifications* (Reference 14) and consistency with the assumptions used in the other LOCA analyses being performed for the SPU.

A post-LOCA sump boron concentration curve was developed for the SPU conditions using the input parameters and assumptions described in the previous section.

6.2.4.4 Acceptance Criteria and Results

There are no specific acceptance criteria in generating the post-LOCA sump boron concentration curve. However, the resulting curve, which is calculated as a function of the initial RCS peak Xenon boron concentration, is included in the Reload Safety Analysis Checklist (RSAC) and is verified for each reload cycle to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA. Adequate post-LOCA boron concentration shows that the long-term core cooling criterion is satisfied.

The post-LOCA sump boron concentration was calculated for RCS boron concentrations of 0 and 1500 ppm assuming the pre-trip RCS boron concentration for peak Xenon concentrations to be 100 ppm lower than the equilibrium case. Figure 6.2-12 shows the post-LOCA sump boron concentration curve.

With respect to long-term core cooling, the SBLOCA analysis discussed in subsection 6.2.2 modeled the ECCS flow enthalpy change during the switchover from cold-leg injection to cold-leg recirculation. For LBLOCA, the minimum flows provided by the ECCS for switchover from cold-leg injection to cold-leg recirculation are adequate to provide long-term core cooling.

6.2.4.5 Conclusions

A post-LOCA sump boron concentration curve was developed for the uprated conditions. This curve will be used to evaluate the fuel loading arrangement on a cycle-by-cycle basis during the fuel reload process. Provided that the maximum critical boron concentration remains below the post-LOCA sump boron concentration curve (for all rods out, no Xenon, 68° to 212°F), the core will remain subcritical post-LOCA, and decay heat can be removed for the extended period required by the remaining long-lived radioactivity. ECCS flow during the cold-leg recirculation period is adequate to provide long-term core cooling.

6.2.5 References

1. WCAP 12945-P-A, Volume 1 (Rev. 2) and Volumes 2 through 5 (Rev. 1), *Code Qualification Document for Best Estimate LOCA Analysis,* March 1998.

2. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report,* Rev. 18, Docket No. 50-286.

3. 10CFR50.71(e), *Maintenance of Records, Making of Reports,* October 4, 1999.

4. 10CFR 50.46, *Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,* September 16, 2003.

5. 10CFR.50, Appendix K, ECCS Evaluation Models.

6. Regulatory Guide 1.157 *Best-Estimate Calculations of Emergency Core Cooling System Performance* (Draft RS 701-4 published March 1987).

7. WCAP-10054-P-A, *Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code,* N. Lee, et al., August 1985.

8. WCAP-10079-P-A, *NOTRUMP A Nodal Transient Small Break and General Network Code,* August 1985.

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

10. *Decay Energy Release Rates Following Shutdown of Uranium-Fueled Thermal Reactors,* Approved by Subcommittee ANS-5, ANS Standards Committee, October 1971.

11. Letter CLC-NS-309 from C. L. Caso to T. M. Novak, Chief, Reactor Systems Branch, NRC, from Manager, Safeguards Engineering, Westinghouse, April 1, 1975.

12. WCAP-9272-P-A, *Westinghouse Reload Safety Evaluation Methodology,* July 1985.

13. WCAP-8339, Westinghouse *ECCS System Evaluation Model - Summary,* June 1974.

14. Appendix A to Facility Operating License DPR-64 for Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, Inc., *Indian Point Nuclear Generating Plant Unit No. 3 Docket No. 50-286 Technical Specifications and Bases.*

Table 6.2-1

IP3 BELBLOCA Results

	Analysis Value	Acceptance Criteria
95th Percentile PCT (°F)*	1944	< 2200
Maximum Cladding Oxidation (%)*	7.60	< 17
Maximum Hydrogen Generation (%)*	0.620	< 1
Coolable Geometry	Core remains coolable	Core remains coolable
Long-Term Cooling	Core remains cool in long term	Core remains cool in long term

Note:

* Calculated using the methodology in the following reference:
WCAP-12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1).

Table 6.2-2 NOTRUMP Transient Results			
Event Time (sec)	**2-Inch**	**3-Inch**	**4-Inch**
Break Initiation	0.0	0.0	0.0
Reactor Trip Signal	55.9	22.8	13.0
S-Signal	71.2	30.2	16.1
SI Begins	99.0	58.0	43.9
Loop Seal Clearing*	1251	582	312
Core Uncovery	1738	765	601
Accumulator Injection Begins	N/A	1688	890
Core Recovery	N/A	N/A	2560

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

Table 6.2-3 Beginning-of-Life (BOL) Rod Heatup Results			
	2-Inch	**3-Inch**	**4-Inch**
Time-in-Life	BOL	BOL	BOL
PCT (°F)	1182	1543	1380
PCT Time (s)	3518	1954	1053
PCT Elevation (ft)	11.5	11.75	11.25
HR Burst Time (s)	N/A	N/A	N/A
HR Burst Elevation (ft)	N/A	N/A	N/A
Max. Local ZrO_2 (%)	0.12	1.04	0.21
Max. Local ZrO_2 Elev (ft)	11.25	11.75	11.25
Hot Rod Axial Avg. ZrO_2 (%)	<1.0	<1.0	<1.0

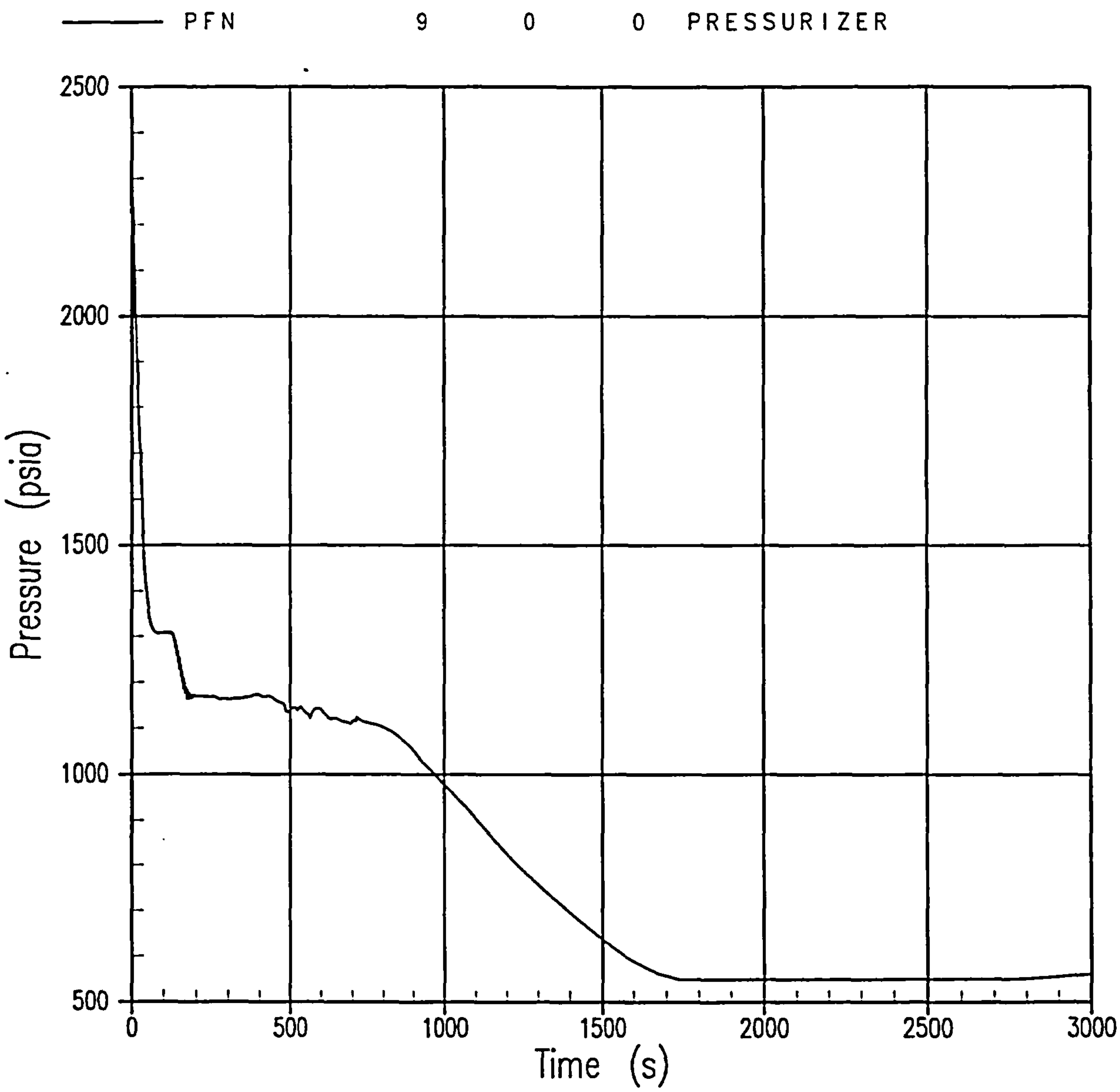

Figure 6.2-1

3-Inch Break Case, Pressurizer Pressure

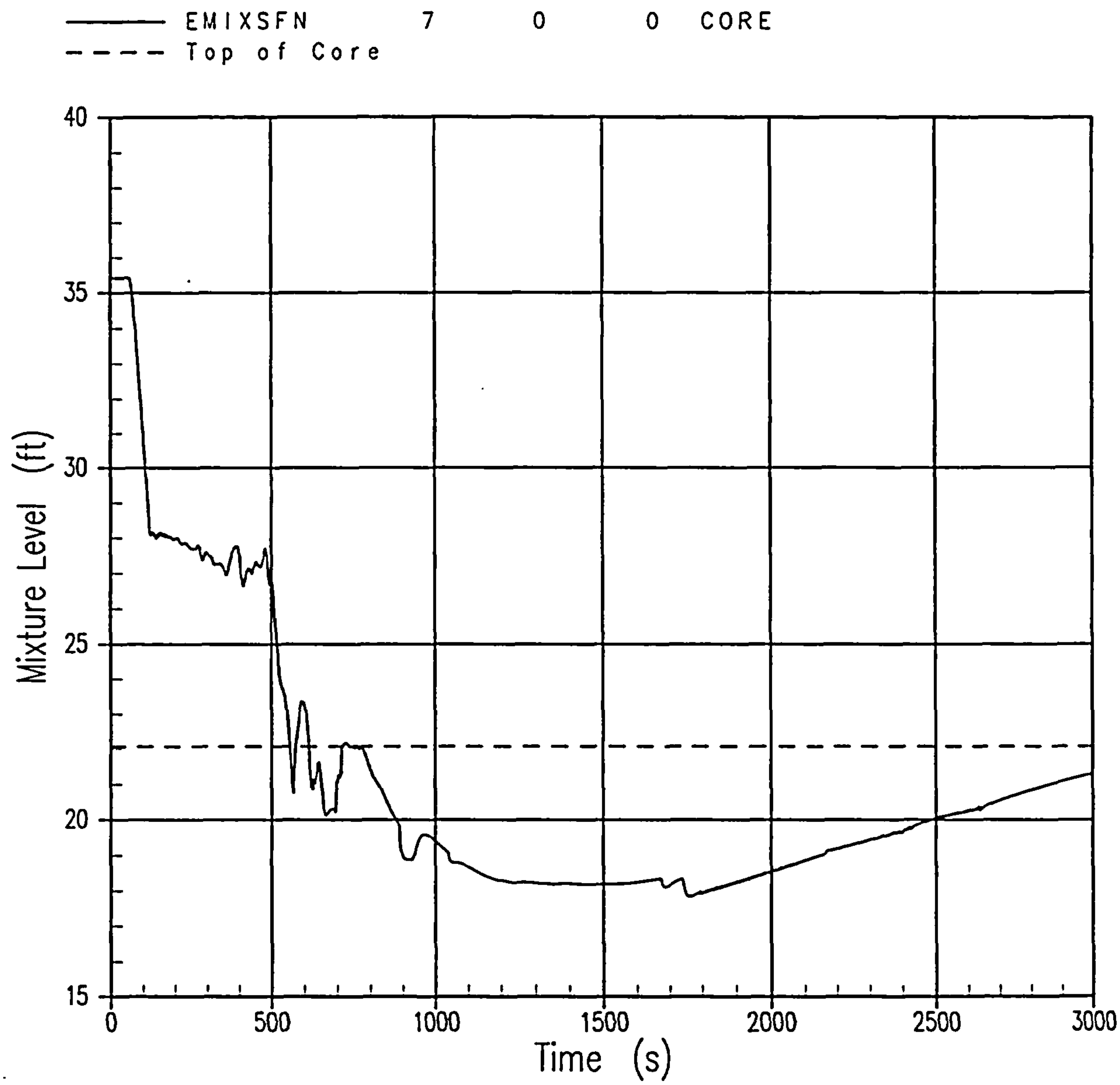

Figure 6.2-2

3-Inch Break Case, Core Mixture Level

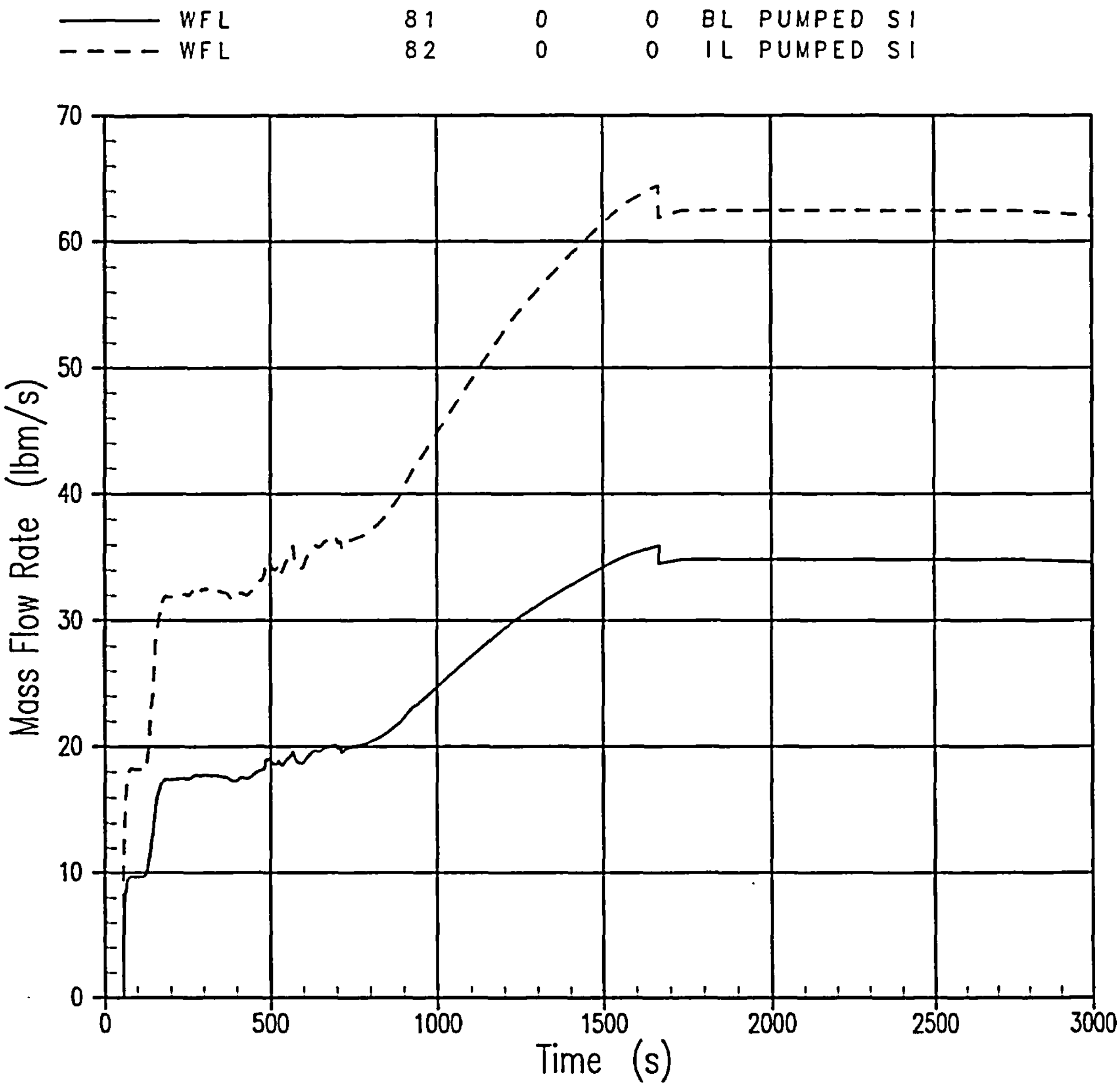

Figure 6.2-3

3-Inch Break Case, Broken Loop, and Intact Loop Pumped SI Flow Rate

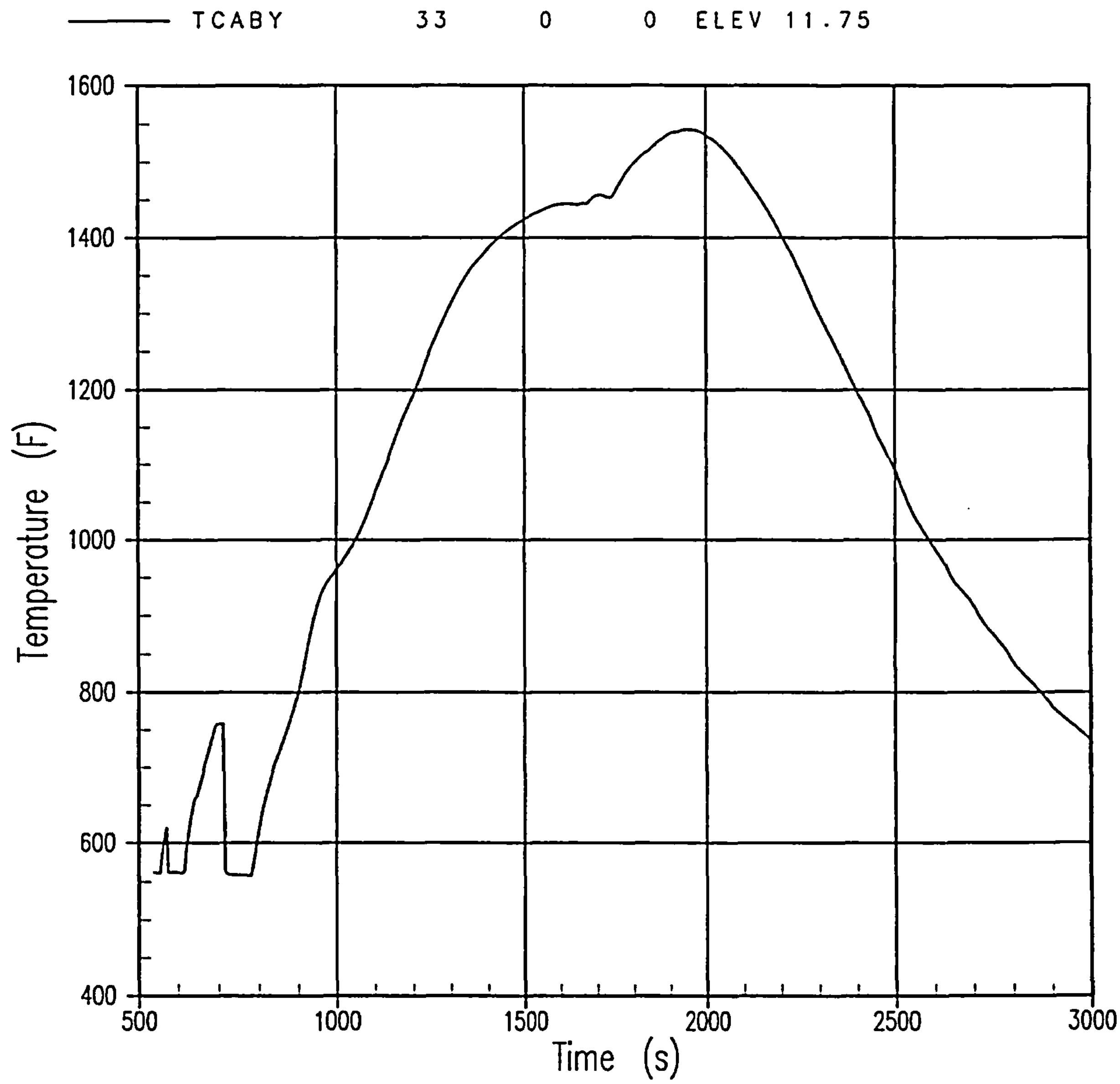

Figure 6.2-4

3-Inch Break Case, PCT at PCT Elevation (11.75 ft)

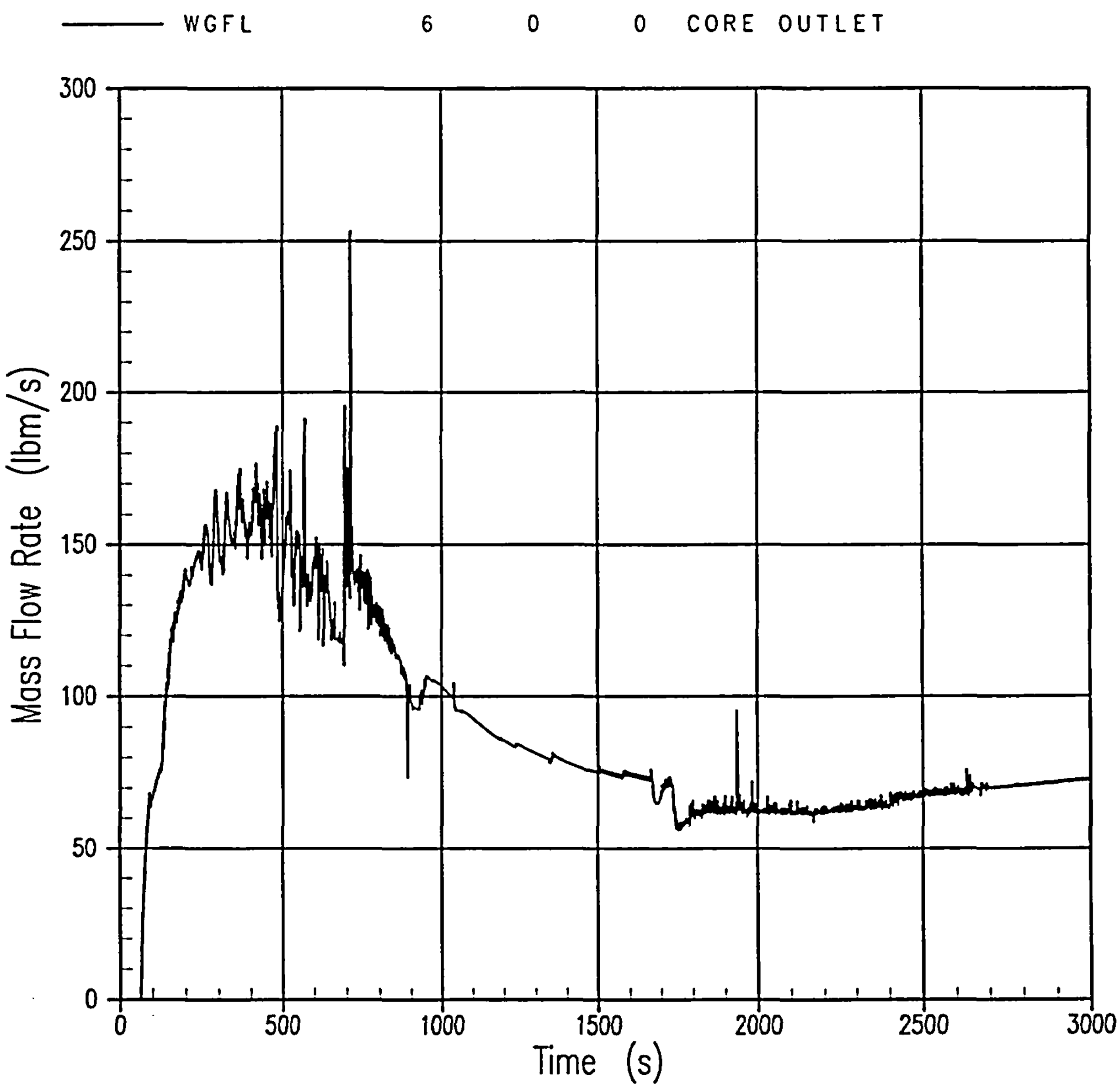

Figure 6.2-5

3-Inch Break Case, Core Exit Steam Flow

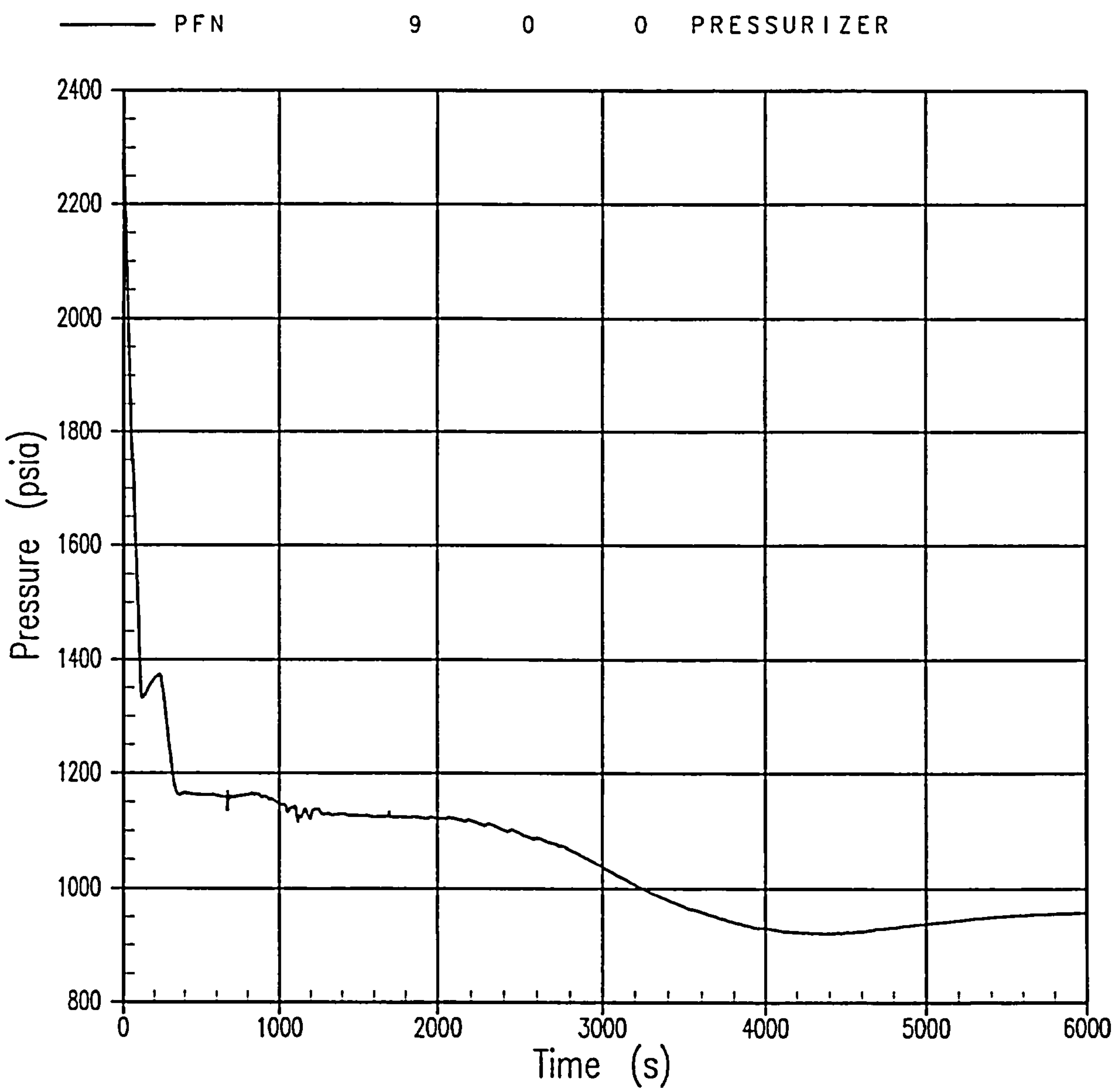

Figure 6.2-6

2-Inch Break, Pressurizer Pressure

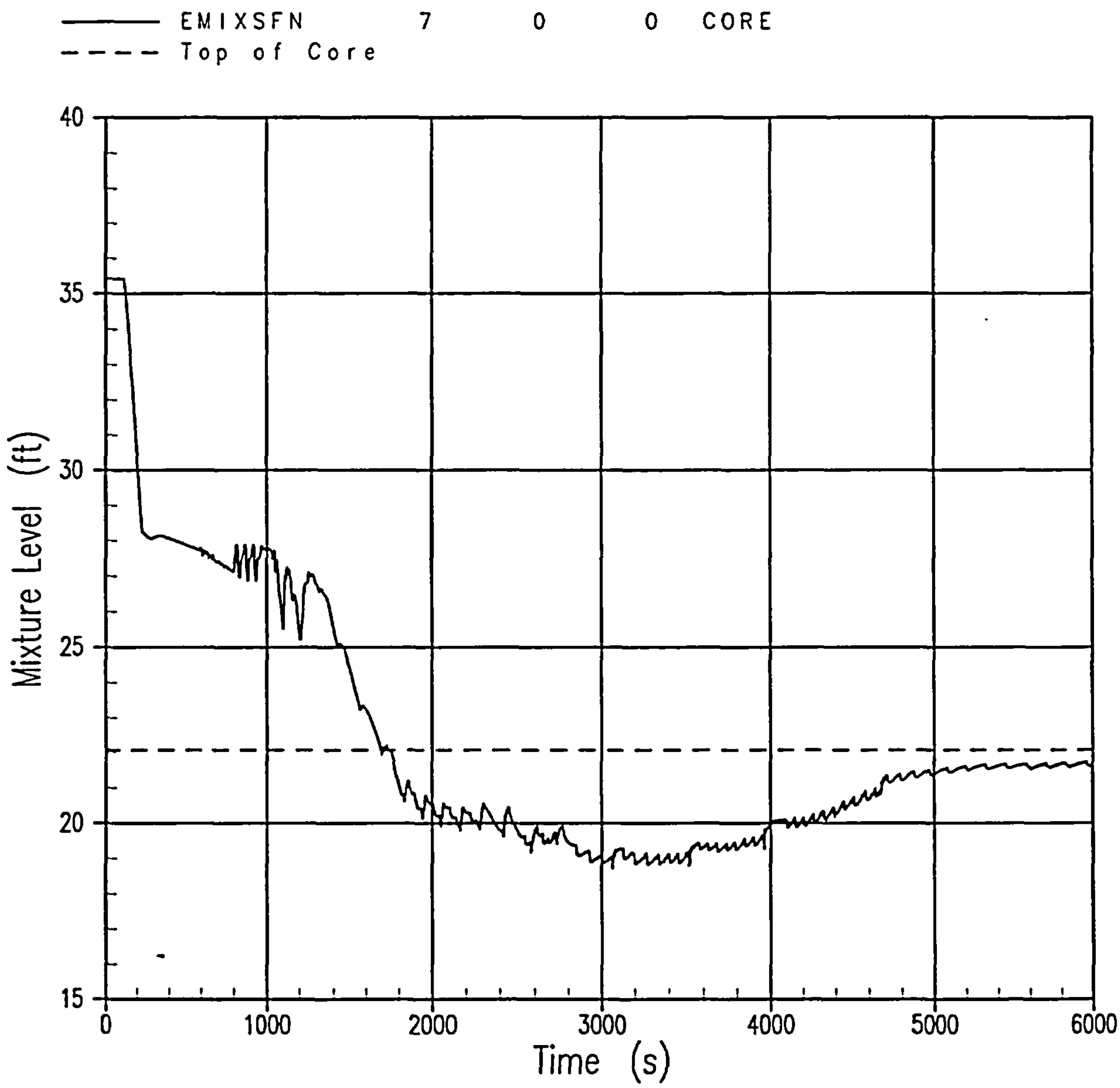

Figure 6.2-7

2-Inch Break, Core Mixture Level

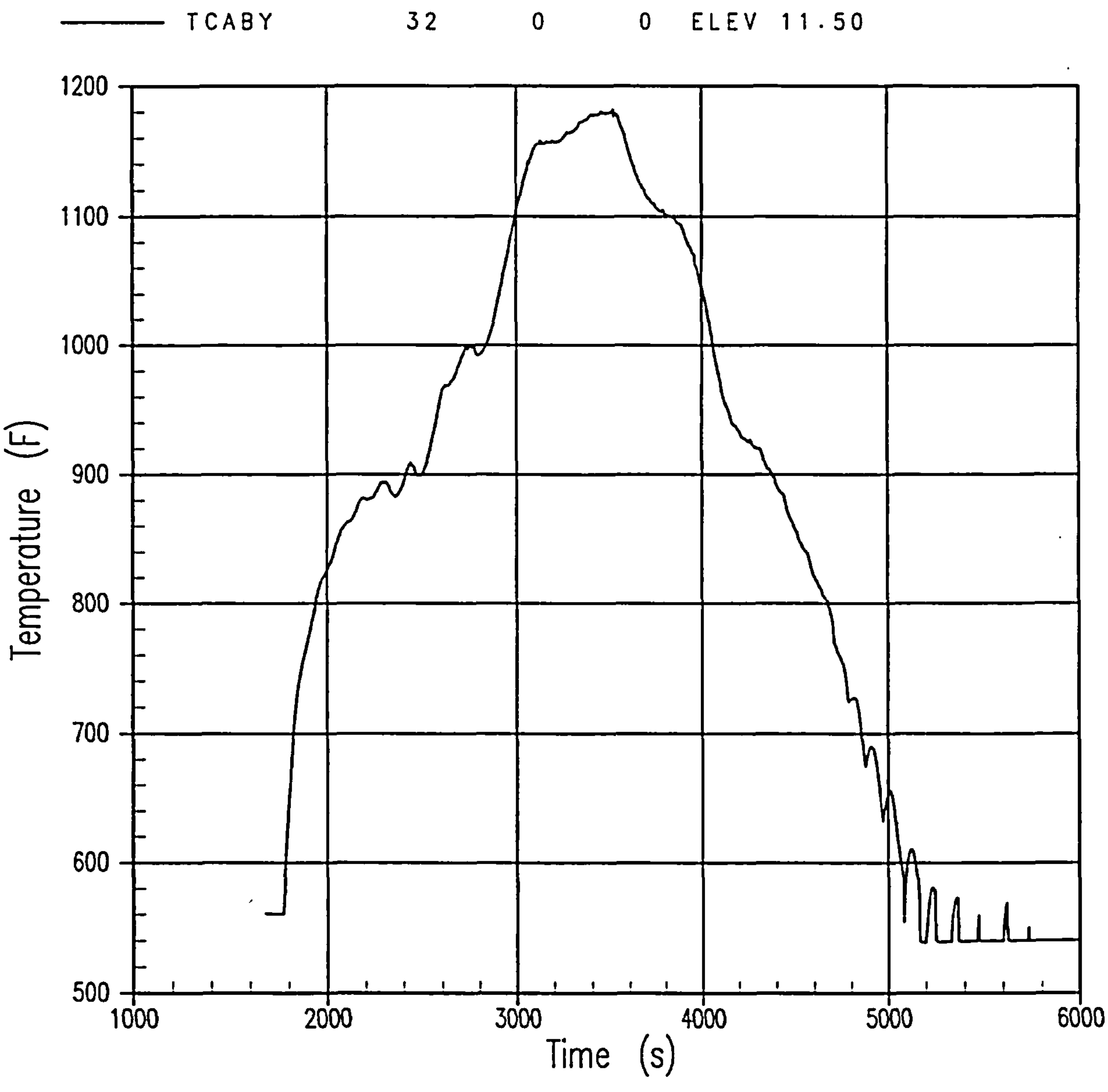

Figure 6.2-8

2-Inch Break, PCT at PCT Elevation (11.5 ft)

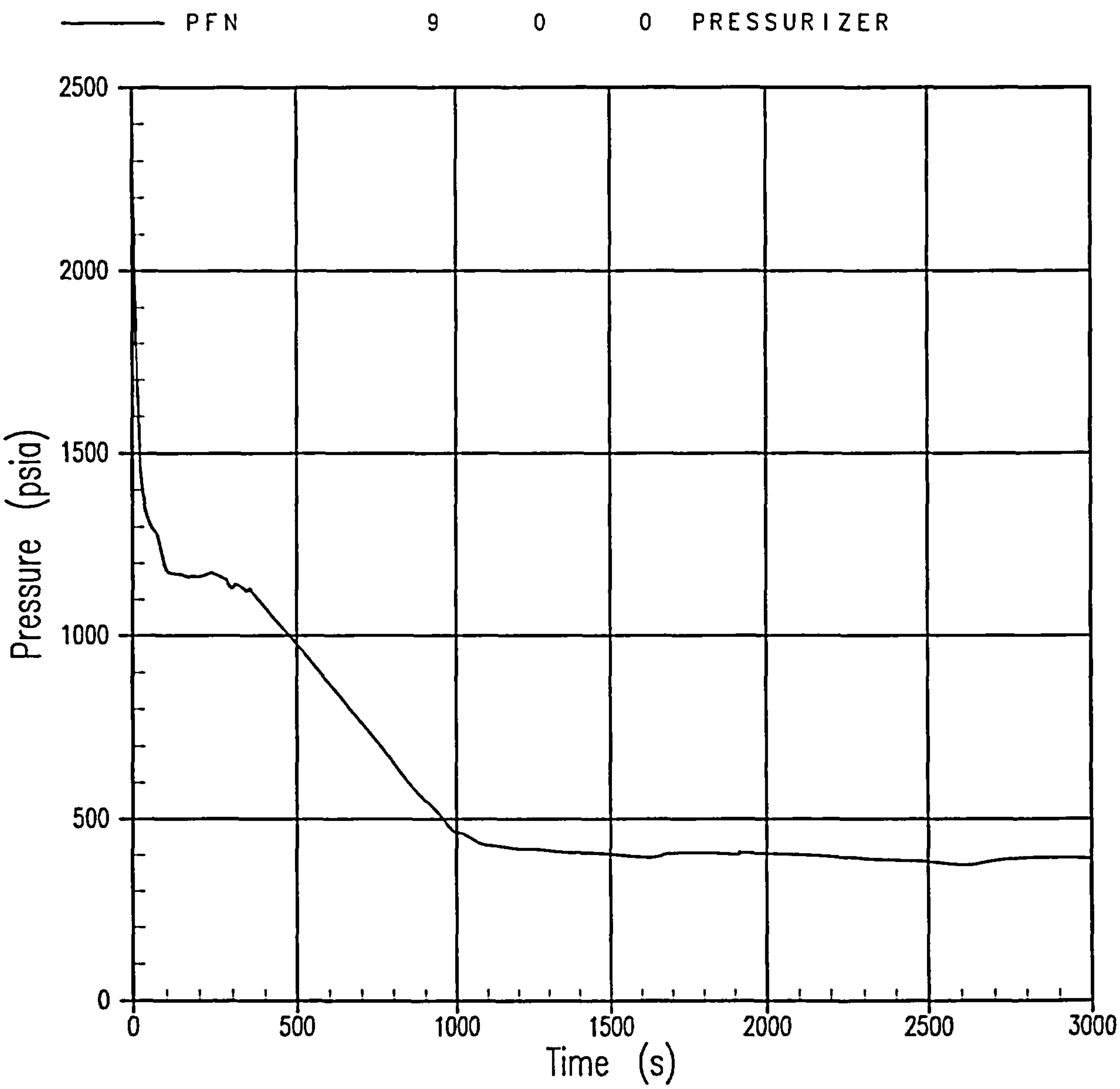

Figure 6.2-9

4-Inch Break, Pressurizer Pressure

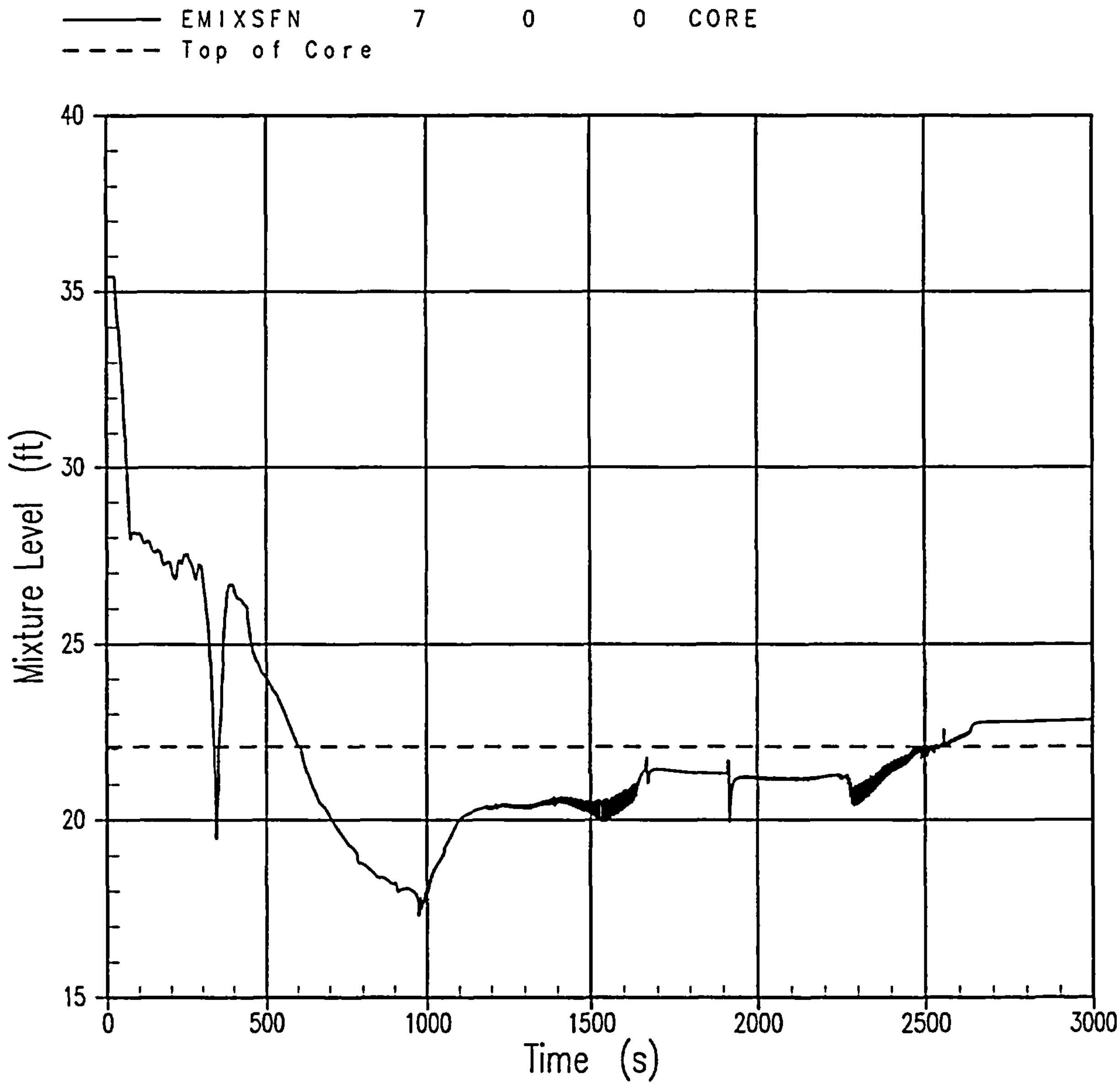

Figure 6.2-10

4-Inch Break, Core Mixture Level

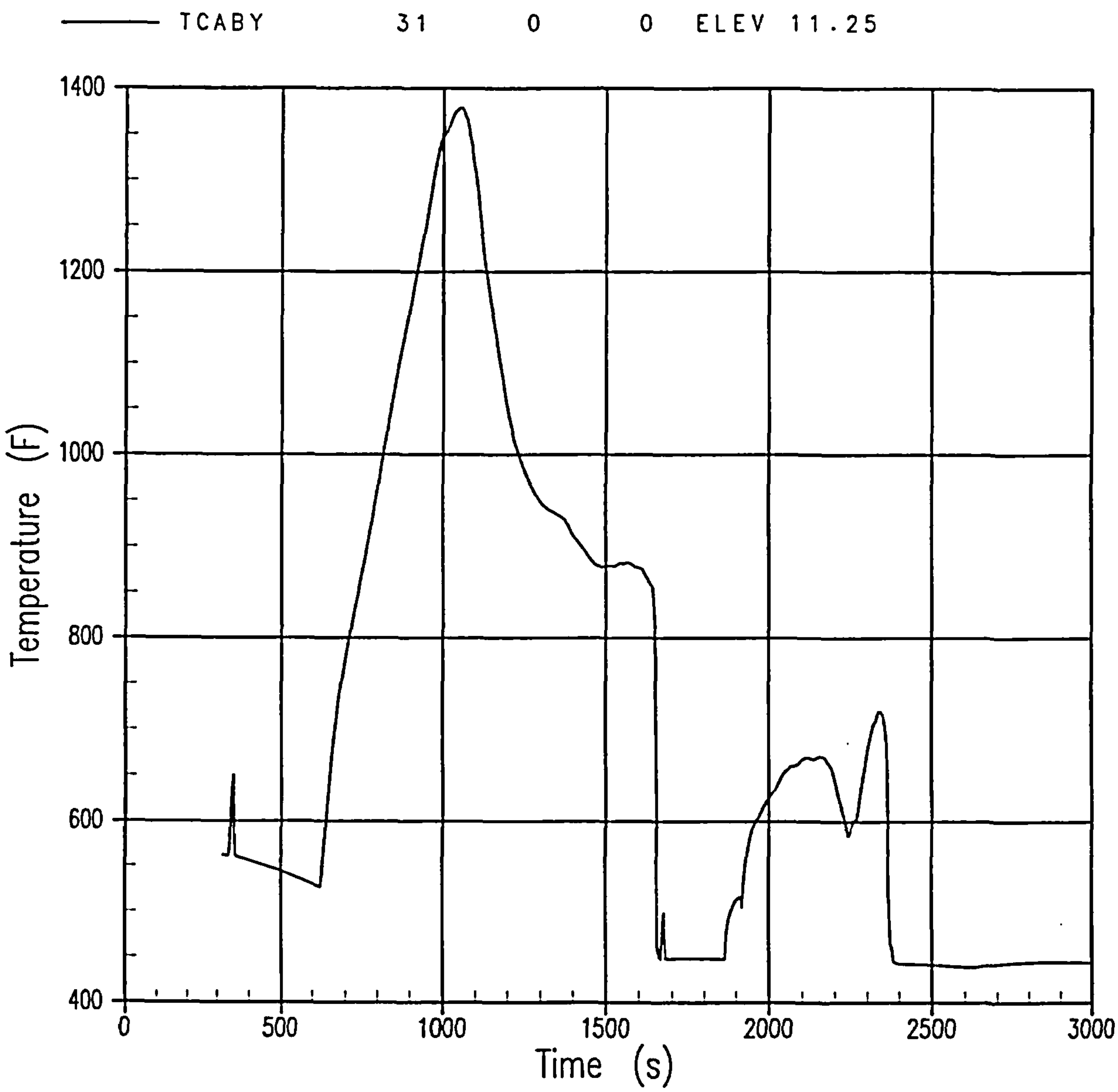

Figure 6.2-11

4-Inch Break, PCT at PCT Elevation (11.25 ft)

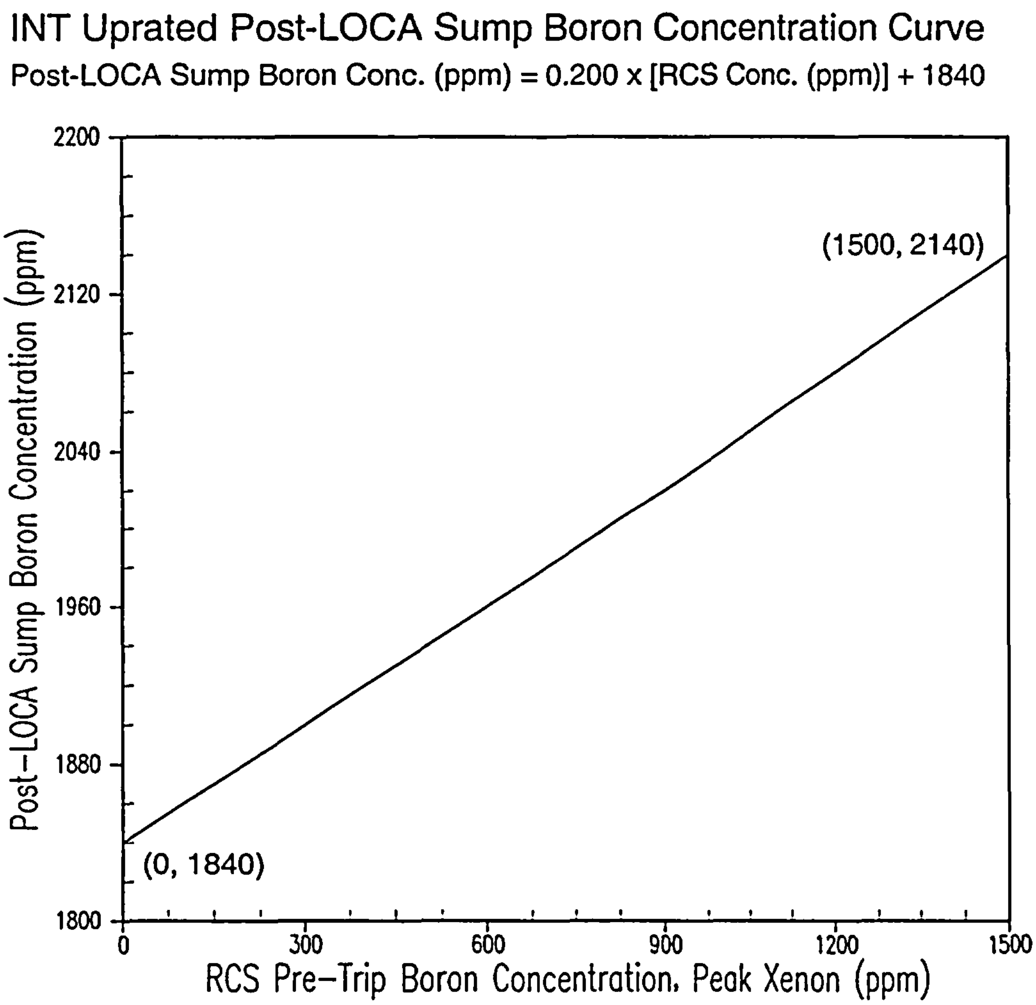

Figure 6.2-12

Post-LOCA Sump Boron Concentration Curve

6.3 Non-Loss-of-Coolant Accident Transients

6.3.1 Introduction

To support the Indian Point Unit 3 (IP3) stretch power uprate (SPU), all of the *Updated Final Safety Analysis Report* (UFSAR) Chapter 14 non-loss-of-coolant accident (LOCA) analyses were evaluated to determine the acceptability of plant operation at the uprated conditions. The uprated conditions addressed are those defined in Table 2.1-2 of this report for the IP3 SPU. The non-loss-of-coolant accident (non-LOCA) events considered herein are listed in Table 6.3-1, along with the corresponding section number in this report and the applicable UFSAR section(s).

The non-LOCA safety analysis methodology used to support the SPU was the same as that applied for the current licensing basis non-LOCA analyses. For some non-LOCA events, the SPU analyses were performed using the RETRAN-02 (RETRAN) computer code, which employs the same methods and methodology used in the current non-LOCA safety analyses that use the LOFTRAN code. For certain applications, RETRAN was used in combination with other computer codes, such as VIPRE-01 (VIPRE) for reactor core subchannel thermal-hydraulic calculations, a neutronic code such as ANC, and a fuel performance code such as PAD (as described in Section 1 of this document). RETRAN is approved for use in non-LOCA safety analyses by the NRC in the *Safety Evaluation Report* (SER) for WCAP-14882-P-A (Reference 1).

Table 6.3-1 contains a list of non-LOCA events along with the corresponding non-LOCA computer codes used. The RETRAN code has been explicitly approved by the NRC for use on each of the non-LOCA events that were analyzed using RETRAN for the SPU (as shown in Table 6.3-1 of this report and documented in Table 1 of the SER of WCAP-14882-P-A [Reference 1]). The RETRAN model used in the IP3 non-LOCA SPU safety analyses simulates a Westinghouse four-loop plant design, applicable to IP3, as described and presented in WCAP-14882-P-A. For each non-LOCA event analyzed, a conservative set of initial conditions and input assumptions was used to generate a conservative, plant-specific transient condition. The event and analysis conditions are provided for each non-LOCA event in subsections 6.3.2 through 6.3.15 of this document. In performing the required analyses for reload cores, Westinghouse uses approved methodology (Reference 2), which provides for using conservative code input so as to bound the expected conditions for subsequent reloads.

Where applicable, the Revised Thermal Design Procedure (RTDP) methodology discussed in WCAP-11397-P-A (Reference 3) was used in the non-LOCA analyses. The RTDP methodology statistically combines the uncertainties of the plant operating parameters (for example, power, temperature, pressure, and flow) into the design limit departure from nucleate boiling ratio limit DNBR values that are used as an acceptance criterion in the DNBR-related non-LOCA analyses.

In conjunction with the SPU, the non-LOCA safety analyses support several other related changes that directly affect the UFSAR Chapter 14 non-LOCA safety analyses. These changes are summarized in the sections that follow.

Power Uprating

The changes in plant conditions that were considered to be directly associated with the SPU are shown in Tables 2.1-1 and 2.1-2 of this document, and discussed below.

NSSS power was increased from 3082 to 3230 MWt. This resulted in an increase in reactor power from 3068 to 3216 MWt, and a corresponding increase in rod average linear power from 6.34 to 6.644 kW/ft.

IP3 measured flow values provided sufficient margin to increase minimum measured flow and thermal design flow (TDF). Thermal design flow was increased from 323,600 to 354,400 gpm for the SPU. The minimum measured flow (MMF), used in conjunction with the statistical RTDP departure from nucleate boiling (DNBR) methodology described in subsection 6.1.4.1, was increased from 330,800 to 364,700 gpm. These flows were increased to provide margin for DNB-related accidents and transients. Core bypass flow fractions of 7.5 percent (non-statistical) and 6.8 percent (statistical) were assumed. These core bypass flow conditions were increased from those currently analyzed to support a possible upper head temperature reduction in the future.

The maximum reactor vessel average coolant temperature (T_{avg}) was decreased from 574.7° to 572.0°F. The minimum full-power T_{avg} was assumed to be 549.0°F.

The non-LOCA safety analyses now support a range of main feedwater temperatures. The full-power feedwater temperature range is 390.0° to 433.6°F for an NSSS power of 3230 MWt and 390.0° to 431.5°F for an NSSS power of 3182 MWt. The previous analyses supported a full-power feedwater temperature of 427.8°F. The feedwater temperature at hot zero power (HZP) conditions is assumed to be 70°F. Feedwater temperatures at part-power conditions increased proportionally with power between HZP and full-power conditions.

The maximum steam generator tube plugging (SGTP) levels were decreased from 24-percent uniform/30-percent peak to 10-percent uniform for the Model 44F steam generators. Symmetric reactor coolant loop (RCL) flow conditions consistent with a maximum 10-percent uniform SGTP were assumed.

Overtemperature ΔT and Overpower ΔT Reactor Trip Setpoints

The overtemperature ΔT and overpower ΔT (OTΔT/OPΔT) reactor trip functions were assumed to be available in several non-LOCA transient analyses to ensure that the departure from nucleate boiling (DNB) design basis and the fuel centerline melting design basis would be satisfied. The OTΔT and OPΔT reactor trip safety analysis setpoints were generated assuming steady-state conditions and were based on a number of inputs, including the nominal core thermal power and the core thermal safety limits. The core thermal safety limits are the locus of core inlet temperature conditions at which the DNBR is equal to the safety analysis limit value for a range of powers and a range of pressures.

As a result of the increased core thermal power for the SPU and to improve human performance in instrumentation settings at the IPEC site, the safety analysis limit DNBR and core thermal safety limits were revised, resulting in a change to the OTΔT and OPΔT reactor protection trip setpoints. The safety analysis limit DNBR was revised from 1.54 (typical and thimble cell) to 1.45 (typical and thimble cell) based on the WRB-1 DNB correlation. The revised core thermal safety limits presented in Figure 6.3-1 (and Figure 2.1-1 of the *Improved Technical Specifications* [ITS]) were based on the SPU conditions defined in Table 2.1-2 of this report.

The safety analysis values for the OTΔT and OPΔT reactor protection trip setpoints, based on the revised core thermal safety limits, are as follows:

Overtemperature ΔT Reactor Trip Setpoint

$$\Delta T \leq \Delta T_o \, [K_1 - K_2 \, [(1+\tau_1 s) / (1+\tau_2 s)] \, (T_{avg} - T') + K_3 \, (P - P') - f(\Delta I)]$$

Where:
$K_1 = 1.42$

$K_2 = 0.022/°F$

$K_3 = 0.00070/\text{psi}$

$\tau_1 = 25.0$ seconds

$\tau_2 = 3.0$ seconds

$T' \leq 572°F$

$P' = 2235$ psig

K_1 = Preset manually adjustable bias (fraction)

K_2 = Preset manually adjustable gain based on the effect of temperature on the design limits (1/°F)

K_3 = Preset manually adjustable gain based on the effect of pressure on the design limits (1/psi)

ΔT_o = Reference ΔT, measured at nominal full power for the channel being calibrated (°F)

T_{avg} = Measured average temperature for each calibrated channel (input from instrument racks) (°F)

T' = Reference T_{avg}, measured at nominal full power for the channel being calibrated (°F)

P = Measured pressurizer pressure (input from instrument racks) (psig)

P' = Nominal pressurizer pressure (2235 psig)

$f(\Delta I)$ = Function of the indicated difference between the top and bottom detectors of the power range nuclear ion detectors (see below)

- For each percent that ΔI is < -15.75 percent, reduce the OTΔT trip setpoint by the equivalent of 4.000-percent RTP rated thermal power (RTP).
- For ΔI between –15.75 percent and +6.9 percent, the OTΔT $f(\Delta I)$ function is equal to 0.0.
- For each percent that ΔI is > +6.9 percent, reduce the OTΔT trip setpoint by the equivalent of 3.333-percent RTP.

$(1 + \tau_1 s)/(1 + \tau_2 s)$ = Lead/lag compensation

Where: τ_1 = Preset manually adjustable dynamic compensation time constant (Lead for OTΔT trip setpoint) (seconds)

τ_2 = Preset manually adjustable dynamic compensation time constant (Lag for OTΔT trip setpoint) (seconds)

s = Laplace transform operator (seconds^{-1})

Overpower ΔT Reactor Trip Setpoint

$$\Delta T \leq \Delta T_o \left[K_4 - K_5 \left[(\tau_3 s) / (1 + \tau_3 s)\right] (T_{avg}) - K_6 (T_{avg} - T')\right]$$

Where: K_4 = 1.164

K_5 = 0.0/°F for decreasing T_{avg}; and

= 0.0175/°F for increasing T_{avg}

K_6 = 0.0/°F for $T_{avg} \leq T'$; and

= 0.0015/°F for $T_{avg} > T'$

τ_3 = 10.0 seconds

$T' \leq$ 572°F

K_4 = Preset manually adjustable bias (fraction)

K_5 = Preset manually adjustable gain that compensates for piping and thermal time delays (1/°F)

K_6 = Preset manually adjustable gain that accounts for the effects of coolant density and heat capacity on the relationship between ΔT and thermal power (1/°F)

ΔT_o = Reference ΔT, measured at nominal full power for the channel being calibrated (°F)

T_{avg} = Measured average temperature for each calibrated channel (input from instrument racks) (°F)

T' = Reference T_{avg}, measured at nominal full power for the channel being calibrated (°F)

$(\tau_3 s)/(1 + \tau_3 s)$ = Rate/lag compensation

Where: τ_3 = Preset manually adjustable dynamic compensation time constant (rate lag time constant for OPΔT trip setpoint) (seconds)

s = Laplace transform operator (seconds^{-1})

The safety analysis values assumed for the time constants (first order lags) on the measurements of T_{avg} and ΔT used in the OTΔT and OPΔT equations are 4.5 seconds.

The nominal values assumed for T_{avg} and pressure in the OTΔT and OPΔT setpoint calculations bound the SPU conditions for a nominal operating T_{avg} from 549.0 to 572.0°F.

With respect to Reactor Coolant System (RCS) pressure, the OTΔT and OPΔT reactor trip functions were applicable for a range of pressurizer pressures from 1850 to 2470 psia. This analyzed range bounds pressure conditions between the low- and high-pressurizer pressure reactor trip settings with consideration given to the appropriate uncertainties.

To ensure proper operation of the OTΔT and OPΔT reactor trip functions over the entire range of applicable full power operating RCS temperatures (T_{avg} from 549.0° to 572.0°F), the instrumentation must be capable of measuring temperatures over the following ranges:

$$511°F \leq T_{cold} \leq 596°F$$

$$547°F \leq T_{avg} \leq 615°F$$

$$583°F \leq T_{hot} \leq 634°F$$

Also, to ensure proper operation of the OTΔT and OPΔT reactor trip functions over a reduced, more realistic range of applicable full power operating RCS temperatures (T_{avg} from 562.0° to 572.0°F), the instrumentation must be capable of measuring temperatures over the following ranges:

$$525°F \leq T_{cold} \leq 596°F$$

$$560°F \leq T_{avg} \leq 615°F$$

$$596°F \leq T_{hot} \leq 634°F$$

As such, the revised instrumentation ranges that have been chosen for IP3 after implementation of the SPU to ensure proper operation of the OTΔT and OPΔT reactor trip functions over a realistic full power operating T_{avg} range of 562.0° to 572.0°F are as follows:

$$520°F \leq T_{cold} \leq 640°F$$

$$540°F \leq T_{avg} \leq 615°F$$

$$520°F \leq T_{hot} \leq 640°F$$

Should a cycle-specific full power operating T_{avg} value be chosen to be below 562.0°F, the instrumentation ranges will need to be revised to protect the more broad ranges presented above for a full power operating T_{avg} range of 549.0° to 572.0°F.The effect of the change in the core thermal safety limits as well as the resulting changes in the OTΔT and OPΔT reactor protection trip setpoints are addressed for non-LOCA transients in the evaluations and analyses described in the following sections.

Auxiliary Feedwater

To support the SPU, a requirement was specified for additional auxiliary feedwater (AFW) flow to preclude a pressurizer water-solid condition for the loss-of-normal feedwater (LONF) and loss-of-all AC power (LOAC) to the station auxiliaries event analyses. The LONF and LOAC events address an LONF (from pump failures, valve malfunctions, or LOAC), which results in a reduction in capability of the secondary system to remove heat generated in the reactor core. If an alternate source of feedwater is not supplied to the plant, residual heat following a reactor trip may heat the primary system water to the point at which water relief from the pressurizer occurs, potentially generating a more serious plant condition without other incidents occurring independently. To ensure acceptable results were obtained in the LONF/LOAC event analyses (addressed in subsections 6.3.7 and 6.3.8), operator action was assumed at 10 minutes following reactor trip to align an additional train of AFW (aside from the single motor-driven AFW train automatically actuated on a low-low steam generator water level signal).

Neutronics/Reactivity Modeling

To support future reload design activities with the uprated core power, several neutronics-related analysis input assumptions were changed.

- To provide margin for future reload design activities, the change in boron concentration from the maximum critical boron concentration (with all rods inserted) to a critical boron concentration at which k-effective < 0.95 was increased from 570 to 660 ppm for the Mode 6 (refueling) boron dilution analysis. The Mode 6 boron dilution analysis is presented in subsection 6.3.5 of this document.

- To support the uncontrolled rod cluster control assembly (RCCA) withdrawal at power analysis with respect to RCS overpressure concerns, the maximum reactivity insertion rate was limited to ≤66 pcm/sec (88 pcm/in), corresponding to maximum differential RCCA worth at maximum RCCA withdrawal rate. The analysis of this event is discussed in subsection 6.3.3.

Fuel Temperatures

Revised fuel temperatures generated in support of the SPU conditions were applied as appropriate in the non-LOCA safety analyses.

Reactor Trip

The various instrumentation delays associated with each reactor trip function were conservatively modeled in the non-LOCA safety analyses. The total delay time is defined as the time from when trip conditions are reached to the time the rods are free to fall. The safety analysis trip setpoint and maximum time delay assumed in the non-LOCA safety analysis for each reactor trip function at SPU conditions are shown in Table 6.3-2.

Table 6.3-3 summarizes key analysis assumptions considered in the IP3 SPU non-LOCA analyses and evaluations.

Event Classification

The non-LOCA accidents are classified by the American Nuclear Society (ANS) as 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 that are expected to occur frequently or regularly. These occurrences are accommodated with 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 will 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 will 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 10CFR20 limits; however, they will not be enough to interrupt or restrict public use of those areas beyond the exclusion radius. Condition III incidents will 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 will not result in an undue risk to public health and safety exceeding the guidelines of 10CFR100. No consequential loss of function of systems required to mitigate the event can occur.

The results of all analyses and evaluations demonstrated that applicable safety analysis acceptance criteria were satisfied at the SPU conditions detailed in Table 2.1-2 of this report.

6.3.2 Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition

6.3.2.1 Introduction

An RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of control rods resulting in a power excursion. While the probability of a transient of this type is extremely low, operator action or a malfunction of the Reactor Control Rod Drive System could cause such a transient. This could occur with the reactor either subcritical or at power. The at-power case is discussed later in subsection 6.3.3.

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

The RCCA drive mechanisms are wired into pre-selected bank configurations that remain the same throughout reactor life. These circuits prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power supplied to the banks is controlled so that no more than two banks can be withdrawn at the same time and in their defined withdrawal sequence. The RCCA drive mechanisms are of the magnetic latch type, and coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming simultaneous withdrawal of the combination of the two sequential control banks having the maximum combined worth at maximum speed. The maximum reactivity insertion rate, even with these assumptions, is well within the capability of the Reactor Protection System (RPS) to prevent core damage.

Should a continuous RCCA withdrawal be initiated, the following automatic features of the RPS will terminate the transient:

- Source range neutron flux reactor trip - actuated when either of two independent source range channels indicate above a pre-selected, manually adjustable setpoint. This trip function can be manually bypassed only after either of two intermediate range flux channels indicate above a specified level. It is automatically reinstated when both intermediate channels indicate below a specified level.

- Intermediate-range neutron-flux reactor trip - actuated when either of two independent intermediate range channels indicate above a pre-selected, manually adjustable setpoint. This trip function can be manually bypassed only after 2 of 4 power range channels indicate above approximately 10 percent full-power. It is automatically reinstated when 3 of 4 channels indicate below this value.

- Power-range high-neutron-flux reactor trip (low setting) - actuated when 2 of 4 power range channels indicate above approximately 25 percent full-power. This trip function can be manually bypassed when 2 of 4 power range channels indicate above approximately 10 percent full-power. It is automatically reinstated when 3 of 4 channels indicate below this value.

- Power-range high-neutron-flux reactor trip (high setting) - actuated when 2 of 4 power range channels indicate above a preset setpoint. This trip function is always active.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast initial increase terminated by the reactivity feedback effect of the negative Doppler power coefficient. This self-limitation of the initial power increase is of prime importance since it limits nuclear power to an acceptable level prior to protection system action. After the initial 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 fuel damage. In addition, control rod stops on high-intermediate range flux level (1 of 2) and high-power range flux level (1 of 4) serve to halt rod withdrawal and prevent the need to actuate the intermediate range flux level trip and power range flux level trip, respectively.

6.3.2.2 Input Parameters and Assumptions

The Standard Thermal Design Procedure (STDP) was used in the accident analysis. To obtain conservative results for the analysis, the following assumptions were made concerning initial reactor conditions:

- *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 power reactivity coefficient, a conservatively low (least negative) value was used.*

- The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because heat transfer time between the fuel and moderator is much longer than nuclear flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. Accordingly, the most positive moderator temperature coefficient was assumed since this yields the maximum rate of power increase.

- The analysis assumed the reactor to be at HZP conditions with a nominal temperature of 547°F. This assumption is more conservative than that of a lower initial system temperature (that is, shutdown conditions) because it yields a larger fuel-to-moderator heat transfer coefficient, a larger specific heat of both moderator and fuel, and a less-negative (smaller absolute magnitude) Doppler coefficient. The less-negative Doppler coefficient 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 also assumes the initial effective multiplication factor (K_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

- 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-percent uncertainty in power range flux trip setpoint (low setting), raising it from the nominal value of 25 to 35 percent. During the transient, the rise in nuclear power is so rapid that the effect of error in the trip setpoint on the actual time of rod release is negligible. In addition, total reactor trip reactivity is based on the assumption that the highest worth control rod assembly is stuck in its fully withdrawn position.

- The maximum positive reactivity insertion rate assumed is greater than that for simultaneous withdrawal of the two sequential control banks having the greatest combined worth at maximum speed (45 inch/min, which corresponds to 72 steps/min).

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

- The analysis assumes initial power to be below that 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.

- The analysis assumes only two reactor coolant pumps (RCPs) in operation. This is conservative with respect to the DNB transient.

6.3.2.3 Description of Analysis

The analysis of the uncontrolled-RCCA-bank-withdrawal-from-subcriticality event was performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 4), was used to calculate the core average nuclear power transient, including various core feedback effects, that is, Doppler and moderator reactivity. Next, the FACTRAN computer code (Reference 5) used the average nuclear power calculated by TWINKLE and performed a fuel rod transient heat transfer calculation to determine average heat flux and temperature transients. Finally, the average heat flux calculated by FACTRAN was used in the VIPRE (Reference 8) computer code for transient DNBR calculations.

6.3.2.4 Acceptance Criteria

The uncontrolled-RCCA-bank-withdrawal-from-subcritical event is considered an ANS Condition II event, a fault of moderate frequency, and is analyzed to ensure that the core and RCS are not adversely affected. This is demonstrated by showing that the minimum DNBR remains above the applicable safety analysis limit and that peak hot spot fuel and clad temperatures remain within acceptable limits.

6.3.2.5 Results

The results of the uncontrolled-RCCA-bank-withdrawal from subcritical analysis performed at the SPU conditions show that the minimum DNBR remains above the safety analysis limit at all times (see subsection 7.2.3.2.6) and that peak fuel centerline temperature remains below that at which fuel melt occurs, as demonstrated in Table 6.3-18. The calculated sequence of events is shown in Table 6.3-4. The nuclear power transient, thermal flux transient, and the clad and fuel temperature transients for this accident are shown in Figures 6.3-2 through 6.3-5, respectively.

6.3.2.6 Conclusions

In the event of an RCCA withdrawal incident from the subcritical condition, the core and RCS would not be adversely affected since the combination of thermal power and coolant temperature results in a minimum DNBR greater than the safety analysis limit. Furthermore, since the maximum fuel temperatures predicted to occur during this event are much less than those required for fuel melting (4800°F), no fuel damage is predicted as a result of this transient at SPU conditions. Clad damage is also precluded since clad temperatures remain within acceptable limits.

6.3.3 Uncontrolled RCCA Assembly Withdrawal at Power

6.3.3.1 Introduction

An uncontrolled-RCCA-bank-withdrawal-at-power event that causes an increase in core heat flux could be the result of an operator error or a malfunction in the Rod Control System. Immediately following initiation of the accident, the steam generator heat removal rate lags behind the core power generation rate. This imbalance between heat removal and heat generation rate causes the reactor coolant temperature to rise. Unless terminated, the power increase and resultant coolant temperature rise could eventually result in DNB and/or fuel centerline melt. Therefore, to avoid damage to the core, the RPS is designed to automatically terminate the transient before the DNBR falls below the safety analysis limit or the fuel rod linear heat generation rate (kw/ft) limit is exceeded.

The automatic RPS features that prevent core damage in an RCCA-bank-withdrawal-incident at-power by actuating a reactor trip include the following:

- Any 2-out-of-4 power range high neutron flux channels exceed the overpower setpoint.
- Any 2-out-of-4 ΔT channels exceed the OTΔT setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against DNB.
- Any 2-out-of-4 ΔT channels exceed the OPΔT setpoint. This setpoint is automatically varied with coolant average temperature so that the allowable heat generation rate (kw/ft) is not exceeded.
- Any 2-out-of-3 high-pressurizer pressure channels exceed the fixed setpoint. This setpoint is less than the set pressure for the PSVs.
- Any 2-out-of-3 high-pressurizer water level channels exceed the fixed setpoint.

In addition to the above listed reactor trips, there are several RCCA bank withdrawal blocks that are not credited in the accident analyses but would serve to limit the severity of this event. These are:

- High neutron flux (1-out-of-4 power range channels)
- OTΔT (1-out-of-4 channels)
- OPΔT (1-out-of-4 channels)

6.3.3.2 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 subsection 6.3.3.5 are representative for this event.

For an uncontrolled-RCCA-bank-withdrawal-at-power accident, the following conservative assumptions are made:

- For the analysis of the minimum DNBR and peak secondary pressure this accident is analyzed with the RTDP (Reference 3). Therefore, initial reactor power, pressurizer pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit. For the analysis of peak RCS pressure, uncertainties in the initial conditions for power, pressurizer pressure and T_{avg} are conservatively applied.

- For reactivity coefficients, two cases are analyzed.

  — Minimum Reactivity Feedback: A zero moderator density coefficient and a least-negative Doppler-only power coefficient form the basis for the BOL minimum reactivity feedback assumption.

  — Maximum Reactivity Feedback: A conservatively large positive moderator density coefficient of 0.54 $\Delta k/g/cm^3$ (corresponding to a large negative MTC) and a most-negative Doppler-only power coefficient formed the basis for the EOL maximum reactivity feedback assumption.

- The reactor trip on high neutron flux is actuated at a value of 118-percent nominal full power, which accounts for all adverse instrumentation and setpoint errors. The ΔT trips included all adverse instrumentation and setpoint errors, with maximum delay for trip signal actuation. A high-pressurizer pressure reactor trip setpoint of 2470 psia, which accounts for all adverse instrumentation and setpoint errors, is assumed in the analysis of the peak RCS pressure.

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

- A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of two sequential control rod banks having the maximum combined differential rod worth at a conservative speed (45 inches/minute, which corresponds to 72 steps/minute).

- Initial power levels of 10, 60, and 100 percent are considered.

- The effect of a full-power RCS T_{avg} window is considered for the uncontrolled-RCCA-bank-withdrawal-at-power analysis. The high end of the full-power T_{avg} window is explicitly analyzed since this is limiting with respect to the DNBR results. For part-power levels, the initial RCS T_{avg} is based on the programmed T_{avg} and the corresponding initial power level.

- The effect of a feedwater temperature window is also considered. The low end of the full-power feedwater temperature window was determined to be limiting with respect to the DNBR results.

6.3.3.3 Description of Analysis

This analysis demonstrates how the protection functions actuate for various combinations of reactivity insertion rates, initial power levels and reactivity feedback conditions.

The rod-withdrawal-at-power event is analyzed with the RETRAN 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 (MSSVs). The program computes pertinent plant variables including temperatures, pressures, power level, and DNBR.

6.3.3.4 Acceptance Criteria

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

The critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

Pressure in the RCS and Main Steam System (MSS) should be maintained below 110 percent of the corresponding design pressures.

6.3.3.5 Results

The results of the uncontrolled-RCCA-withdrawal at power analysis performed at the SPU conditions show that the minimum DNBR remains above the safety analysis limit at all times and that peak RCS and MSS pressures are maintained below 110 percent of the corresponding design pressures, as demonstrated in Table 6.3-18.

Figures 6.3-6 through 6.3-11 show the transient response for a rapid uncontrolled-RCCA-bank-withdrawal incident (66 pcm/sec) starting from 100-percent power with minimum reactivity feedback. Reactor trip on high neutron flux occurs shortly after the start of the accident. Because of the rapid change in nuclear power with respect to the thermal time constants of the fuel, an immediate reactor trip ensures margin to the DNBR safety analysis limit is maintained.

The transient response for a slow uncontrolled RCCA bank withdrawal (1 pcm/s) from 100-percent power with minimum reactivity feedback is shown in Figures 6.3-12 through 6.3-17. Reactor trip on OTΔT occurs after a much longer period, and the temperature rise was consequently larger. Again, the minimum DNBR is greater than the safety analysis limit.

Figure 6.3-18 shows the minimum DNBR as a function of reactivity insertion rate from 100-percent power for both minimum and maximum reactivity feedback conditions. The high neutron flux and OTΔT reactor trip functions provide DNB protection over the range of reactivity insertion rates. The minimum DNBR is greater than the safety analysis limit.

Figures 6.3-19 and 6.3-20 show the minimum DNBR as a function of reactivity insertion rate for RCCA-bank-withdrawal incidents starting at 60- and 10-percent power, respectively. The results are similar to the 100-percent power case. However, as the initial power level decreases, the range over which the OTΔT trip provides protection is effectively increased. In no case does the DNBR fall below the safety analysis limit.

The calculated sequence of events for the two cases discussed above is shown in Table 6.3-5. With the reactor tripped, the plant returns to a stable condition. The plant can subsequently be cooled down further by following normal plant shutdown procedures.

6.3.3.6 Conclusions

The high neutron flux and OTΔT reactor trip functions provide adequate protection over the entire range of possible reactivity insertion rates, that is, the minimum value of the DNBR is always greater than the safety analysis limit. The RCS and MSS are maintained below 110 percent of their design pressures. Therefore, the results of the analysis demonstrate that an uncontrolled-RCCA-withdrawal-at power does not adversely affect the core, RCS, or MSS, and all applicable acceptance criteria are met.

6.3.4 RCCA Drop/Misoperation

6.3.4.1 Introduction

RCCA misoperation accidents 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 that actuates a local alarm and 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 so that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or de-actuation) of the stationary gripper, movable gripper, and lift coils of the control rod drive mechanism (CRDM) withdraws the RCCA held by the mechanism. Mechanical failures are in the direction of insertion or immobility. Note that the operator can deliberately withdraw a single RCCA in a control or shutdown bank since this feature is necessary to retrieve an assembly should one drop accidentally.

A dropped RCCA or RCCA bank is detected by:

- Sudden drop in the core power level as seen by the Nuclear Instrumentation System (NIS)
- 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 that 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 can 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 that exist following a dropped RCCA.

Misaligned RCCAs are detected by:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod deviation alarm
- Rod position indicators

The resolution of the rod position indicator channel is ±5 percent of span (±7.2 inches). Any RCCA can deviate from its group within the limits specified in Table 3.1.4-1 of the ITS (above 85-percent RTP) or within 24 steps (at or below 85-percent RTP) and not cause power distributions exceeding design limits. The deviation alarm alerts the operator when any rod deviates from its group position by more than 5 percent of span. If the rod deviation alarm is not operable, the operator must take action as required by the plant *Technical Specifications.*

6.3.4.2 Input Parameters and Assumptions

For one or more dropped RCCA(s) in the same group, transient statepoints are generated generically and evaluated on a plant-specific, cycle-specific basis, to determine if the acceptance criteria are met. The statepoints, in the form of changes in key parameters from the initial values, are calculated based on the following conservative assumptions.

- This accident is analyzed with the RTDP (Reference 3). Therefore, initial reactor power, pressure, and RCS average temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit calculated using the referenced methodology.

- The transient statepoints are based on generic dropped rod analyses specifically performed to support elimination of turbine runback (on dropped rod). The statepoint analysis bounds a dropped RCCA event for single or multiple dropped RCCAs from the same group of a given bank simulating rod withdrawal block. The statepoint analysis also bounds operation with automatic rod control for all possible single dropped rod worths to address the possibility of a single failure in the rods-on-bottom signal that blocks automatic rod withdrawal.

- A range of MTCs from 0 to -35 pcm/°F was analyzed, which bounds the limiting time in life.

- A range of negative reactivity insertions from 100 to 1000 pcm is assumed to simulate the dropped RCCA event.

- To provide a conservative analysis that minimizes the DNBR, the pressure-reducing functions of the automatic pressure control system are modeled. The pressure-reducing functions modeled are the pressurizer power-operated relief valves (PORVs) and spray.

6.3.4.3 Description of Analysis

Dropped RCCA(s) and RCCA Bank

The transient response following a dropped RCCA event was calculated using a detailed digital simulation of the plant. A dropped RCCA or dropped RCCA bank caused a step decrease in reactivity and the resulting core power generation was determined using the LOFTRAN computer code (Reference 6). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, Rod Control System, steam generators, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. Since LOFTRAN employs a point neutron kinetics model, a dropped rod event was modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped RCCA(s), regardless of the actual configuration of the rod(s) that dropped.

For the evaluation of the dropped RCCA event, generic transient statepoints designed to bound specific plant types were examined and found to be applicable (bounding) for IP3 at SPU conditions. The statepoints representing transient system conditions at the limiting point in the transient were calculated by the LOFTRAN code. No credit for any direct trip due to the dropped RCCA(s) was taken in the generic analysis. The generic analysis also assumed no automatic power reduction features (that is, turbine runback) were actuated by the dropped RCCA(s). The statepoints were provided for conditions that covered the range of reactivity parameters expected to occur during core life.

The statepoints and nuclear models specific for IP3 were used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis was shown to be met using the dropped rod limit lines developed with the Westinghouse version of the VIPRE computer code (Reference 8). The transient response, nuclear peaking factor analysis, and DNB design basis confirmation were performed in accordance with the dropped rod methodology described in WCAP-11394 (Reference 7).

Statically Misaligned RCCA

For the statically misaligned RCCA event, steady-state power distributions were analyzed at SPU power conditions (3216-MWt core) using appropriate nuclear physics computer codes. The VIPRE computer code (Reference 8) was used to determine the $F_{\Delta H}$ peaking factor limits that can meet the safety analysis limit DNBR. The analysis examined the case of the worst rod withdrawn from bank D inserted at the insertion limit with the reactor initially at full power. The analysis assumed this incident to occur at BOL since this resulted in the minimum feedback value (least negative) of the MTC. This assumption maximizes the power rise and minimizes the tendency of the large MTC (most negative) to flatten the power distribution.

6.3.4.4 Acceptance Criteria

Based on frequency of occurrence, a misaligned or dropped RCCA is considered a Condition II event as defined by the ANS. The limiting acceptance criteria for these events is that the critical heat flux should not be exceeded, as demonstrated by precluding DNB, and the peak linear heat generation rate should not exceed a value that could cause fuel centerline melt.

6.3.4.5 Results

Dropped RCCA(s) and RCCA Bank

Following one or more dropped RCCA(s) from the same group, a negative reactivity insertion results. The core is not adversely affected during this period since power is decreasing rapidly. Following the RCCA drop(s), the plant establishes a new equilibrium condition. Depending on the worth of the dropped RCCA(s), power can be reestablished by reactivity feedback. Power may also be recovered as a result of automatic rod control.

When reactivity feedback does not offset the worth of the dropped RCCA(s) with manual rod control assumed (automatic rod withdrawal blocked), there is a cooldown condition until a low pressurizer-pressure reactor trip signal is reached. Figures 6.3-21 through 6.3-23 show a typical transient response at BOL conditions with a small negative MTC of -5 pcm/°F for a dropped RCCA worth of 400 pcm.

When reactivity feedback is large enough to offset the worth of the dropped RCCA(s) with manual rod control assumed (automatic rod withdrawal blocked), reactor power is reestablished at a new equilibrium condition. Figures 6.3-24 through 6.3-26 show a typical transient response at EOL conditions with a large negative MTC of -35 pcm/°F for a dropped RCCA worth of 400 pcm.

With automatic rod control functioning, reactor power promptly drops to a minimum due to the negative reactivity insertion associated with the dropped RCCA(s), and is then recovered under rod control. Figures 6.3-27 through 6.3-29 show a typical transient response at BOL conditions with a small negative MTC of -5 pcm/°F for a dropped RCCA worth of 200 pcm.

With automatic rod control functioning and EOL conditions assumed, the reactor power overshoot is effectively dampened due to the reactivity inserted via cooldown of the RCS as opposed to rods. Figures 6.3-30 through 6.3-32 show a typical transient response at EOL conditions with a large negative MTC of -35 pcm/°F for a dropped RCCA worth of 200 pcm.

In all cases, the minimum DNBR remains above the safety analysis limit DNBR and the peak fuel centerline melt temperature criterion at the SPU condition is met, as demonstrated in Table 6.3-18.

Following plant stabilization, the operator can manually retrieve a dropped RCCA by following approved operating procedures.

Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR occur at significant power levels. These situations arise from cases in which one RCCA is fully inserted or where bank D is fully inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alerts the operator well before the transient approaches the postulated conditions. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the safety analysis limit.

The insertion limits in the COLR may vary from time to time depending on several limiting criteria. The insertion limits on control bank D must be chosen to be above that position that meets the minimum DNBR and peaking factors. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with bank D to its full-power insertion limit and 1 RCCA fully withdrawn, DNBR did not fall below the safety analysis limit when analyzed at SPU conditions. The analysis of this case assumed that the initial reactor power, pressure, and RCS temperature were at their nominal values, with the increased radial peaking factor associated with the misaligned RCCA.

For RCCA misalignment with 1 RCCA fully inserted, the DNBR did not fall below the safety analysis limit when analyzed at SPU conditions. The analysis of this case assumed that the initial reactor power, pressure, and RCS temperatures were at their nominal values, with the increased radial peaking factor associated with the misaligned RCCA.

By meeting the DNBR limit for the RCCA misalignment incident there was no reduction in the ability of the primary coolant to remove heat from the fuel rod. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the limiting design axial power distribution. The resulting linear heat generation rate was below that which would cause fuel melting.

6.3.4.6 Conclusions

Following a dropped RCCA(s) event the plant will return to a stabilized condition. Results of the analysis showed that a dropped RCCA event, with or without a reactor trip, did not adversely affect the uprated core since the DNBR remained above the limit for a range of dropped RCCA worths.

For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (statically misaligned RCCA), the DNBR remained greater than the safety analysis limit at uprated power conditions; thus, there was no reduction in the ability of the primary coolant to remove heat from the fuel rod. After identifying an RCCA group misalignment condition, the operator must take action as required by the plant *Technical Specifications* and operating instructions.

6.3.5 Chemical and Volume Control System Malfunction

6.3.5.1 Introduction

Reactivity can be added to the core with the Chemical and Volume Control System (CVCS) by feeding reactor makeup water into the RCS via the Reactor Makeup Control System. Boron dilution is a manual operation. A Boric Acid Blend System is provided to permit the operator to match the concentration of reactor coolant makeup water to that existing in the coolant at the time. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

There is only a single, common source of dilution water to the blender from the primary water makeup system; inadvertent dilution can be readily terminated by isolating this single source. The operation of the primary water makeup pumps that take suction from the primary water storage tank (PWST) provides the non-borated supply of makeup water to the blender. The boric acid from the boric acid storage tank(s) is blended with the reactor makeup water in the blender, and the composition is determined by the preset flow rates of boric acid and reactor makeup water on the reactor makeup control. The operator must switch from the automatic makeup mode to the dilute mode and move the start-stop switch to start or, alternatively, the boric acid flow controller could be set to zero. Since these are deliberate actions, the possibility of inadvertent dilution is very small. For this dilution water to be added to the RCS, the charging pumps must be running in addition to the primary water makeup pumps. Also, any diluted water introduced into the volume control tank (VCT) must pass through the charging pumps to be added to the RCS.

Thus, the rate of addition of diluted water to the RCS from any source is limited to the capacity of the charging pumps. This addition rate is 294 gpm for all three charging pumps. This is the maximum delivery rate based on a pressure drop calculation comparing the pump curve with the system resistance curve. Normally, only one charging pump is operating while the others are on standby.

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 pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction. Postulated boron dilution events during refueling, startup, and power operation were considered in this analysis.

The CVCS malfunction event was analyzed for the refueling (Mode 6), startup (Mode 2), and power (Mode 1) modes.

6.3.5.1.1 Dilution during Refueling

In a dilution in the refueling mode, the operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation. High count rate is alarmed in the reactor containment and the main control room. The count-rate increase is proportional to the multiplication factor.

6.3.5.1.2 Dilution during Startup

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

This mode of operation is a transitory operational mode in which the operator intentionally dilutes (borates) and withdraws control rods to take the plant critical. During this mode, the plant is in manual control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator has to manually initiate a limited dilution (boration) and subsequently manually withdraw the control rods, a process that takes several hours. The *Technical Specifications* require that the operator ensure 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 after receiving P-6 from the intermediate range. Too fast 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. Failure to perform this manual action could result in a reactor trip and immediate shutdown of the reactor.

6.3.5.1.3 Dilution during Power Operation

In this mode, the plant could be operated in either automatic or manual rod control.

With the reactor in automatic rod control, the power and temperature increase from boron dilution results in insertion of the control rods and a decrease in the available shutdown margin. The rod insertion limit alarms (low and low-low settings) alert the operator that a dilution is in progress. The intent of the analysis in this mode is to show there is sufficient time to determine the cause of the dilution, isolate the reactor water makeup source, and initiate boration before the available shutdown margin is lost (resulting in a return to critical condition).

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise would cause the reactor to reach the OTΔT trip setpoint resulting in a reactor trip. The boron dilution transient in this case would be essentially equivalent to an uncontrolled-RCCA-bank-withdrawal-at-power event. The maximum reactivity insertion rate for a boron dilution is conservatively estimated to be within the range of insertion rates analyzed in the RCCA bank withdrawal at power analysis. The intent of the analysis is to show there is sufficient time for the operator to determine the cause of the dilution, isolate the reactor water makeup source, and initiate boration before the available shutdown margin is lost (resulting in a return to critical condition).

6.3.5.2 Input Parameters and Assumptions

6.3.5.2.1 Dilution during Refueling

Conditions assumed for the analysis were:

- Dilution flow is at the maximum capacity of the charging pumps—294 gpm.
- One RHR pump providing a minimum flow rate of 1000 gpm is normally running except during short time periods, as allowed by the *Technical Specifications.* A minimum active RCS water volume of 3266 ft^3 is assumed. This corresponds to the active RCS volume while on RHR, and conservatively assumes an RCS vessel filled to mid-loop.
- The initial boron concentration is assumed to be 2050 ppm.
- The critical boron concentration following reactor trip is assumed to be 1390 ppm, corresponding to all rods inserted and no xenon condition. The 660-ppm change from the initial condition noted above is a conservative minimum value.

6.3.5.2.2 Dilution during Startup

Conditions assumed for the analysis were:

- Dilution flow is at the maximum capacity of the charging pumps—294 gpm.
- A minimum RCS water volume of 9350 ft^3 is modeled. This corresponds to the active RCS volume taking into account 10-percent uniform SGTP minus the pressurizer and the reactor vessel upper head.
- The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of HZP, rods to insertion limits, and no xenon.
- The critical boron concentration following reactor trip is assumed to be 1550 ppm, corresponding to the HZP, all rods inserted (minus the most reactive RCCA), and no xenon condition. The 250-ppm change from the initial condition noted above is a conservative minimum value.

6.3.5.2.3 Dilution during Full-Power Operation

In this mode, the plant can be operated in either automatic or manual rod control. Conditions assumed for the analysis were:

- Dilution flow is at the maximum capacity of the charging pumps—294 gpm.
- A minimum RCS water volume of 9350 ft^3 is modeled. This corresponds to the active RCS volume (with 10-percent uniform SGTP) minus the pressurizer and reactor vessel upper head.
- The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of HFP, rods to insertion limits, and no xenon.
- The critical boron concentration following reactor trip is assumed to be 1450 ppm, corresponding to the HZP, all rods inserted (minus the most reactive RCCA), and no xenon condition. The 350-ppm change from the initial condition noted above is a conservative minimum value.

6.3.5.3 Description of Analysis

To cover all phases of plant operation, boron dilution during refueling and power modes of operation were considered in this analysis.

Conservative values for necessary parameters were used, that is, high RCS critical boron concentrations, high boron worth, minimum shutdown margins, and lower than actual RCS volumes. These assumptions result in conservative determinations of the time available for operator or system response after detection of a dilution transient in progress.

Conservative analysis methods were used to analyze a CVCS malfunction that resulted in a decrease in boron concentration in the reactor coolant. Minimum reactor coolant volumes and maximum dilution flow rates were conservatively assumed for each case analyzed. The result was a logarithmic decrease in coolant boron concentration according to the equation:

$$dC_B/dt = -\ [Q_{in}/V]\ C_B$$

Where:

C_B = Boron concentration in the RCS

Q_{in} = Maximum dilution flow rate

V = Active volume in RCS

This equation is solved for the time at which the core would become critical or all shutdown margin would be lost. The rate of reactivity insertion due to the dilution is calculated from the dilution rate and the differential boron worth. The results of this analysis were conservative for all cases analyzed.

6.3.5.4 Acceptance Criteria

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 ensured by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and MSS should be maintained below 110 percent 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 was analyzed to ensure 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 DNBR limit and challenge fuel and fuel cladding integrity. A complete-loss-of-plant-shutdown margin could also result in an increase in RCS pressure. This could challenge the pressure design limit for the RCS.

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 were met for those Condition II events, it can be concluded that they were also met for the boron dilution event. Operator action was relied upon to preclude a complete-loss-of-plant-shutdown margin.

Per the current IP3 licensing basis, the minimum times required in order to credit operator action for this event are:

- Refueling: There must be at least 30 minutes between initiation of the event and the time at which plant shutdown margin is lost.
- Startup: There must be at least 15 minutes between initiation of the event and the time at which plant shutdown margin is lost.
- Power Operation: There must be at least 15 minutes between the time of alarm and the time at which plant shutdown margin is lost.

6.3.5.5 Results

6.3.5.5.1 Dilution during Refueling

From initiation of the event, there were 31.74 minutes available for operator action prior to return to criticality.

6.3.5.5.2 Dilution during Startup

From initiation of the event, there were 26.48 minutes available for operator action prior to return to criticality.

6.3.5.5.3 Dilution during Full-Power Operation

From time of alarm while in manual rod control, there were 34.82 minutes available for operator action prior to loss-of-shutdown margin (return to criticality).

From time of alarm while in automatic rod control, there were 36.92 minutes available for operator action prior to loss-of-shutdown margin (return to criticality).

6.3.5.6 Conclusions

The results of this analysis show that in the event of an uncontrolled inadvertent boron dilution, there is sufficient time for operator action to mitigate the consequences of this event prior to a complete-loss-of-shutdown margin, as demonstrated in Table 6.3-18. Therefore, the applicable acceptance criteria are met.

6.3.6 Loss-of-External Electrical Load

6.3.6.1 Introduction

A major loss-of-load (LOL) can result from either a loss-of-external-electrical load or from a turbine trip. A loss-of-external-electrical load can result from an abnormal variation in network frequency or other adverse network operating conditions. For either case, offsite power is available for the continued operation of plant components such as the RCPs. The case of loss-of-all-non-emergency-AC power is presented in subsection 6.3.8 of this document.

For a loss-of-external-electrical load without subsequent turbine trip, no direct reactor trip signal would be generated, as the plant would be expected to trip from the reactor protection system if a safety limit were approached. A continued steam load of approximately 5 percent would exist after total loss-of-external-electrical load because of the steam demand of plant auxiliaries.

For a turbine trip, the reactor would be tripped directly (unless below P-8 power) on a signal from the turbine auto stop oil pressure or turbine stop valves.

If the steam dump valves fail to open following a large LOL, the steam generator safety valves can lift and the reactor can be tripped by the high-pressurizer pressure signal, high-pressurizer water level signal, or OTΔT signal. If feedwater flow is also lost, the reactor can be tripped by a steam generator low-low water level signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly following a large LOL. The pressurizer and steam generator safety valves are sized to protect the RCS and steam generators against overpressure for all load losses without assuming operation of the Steam Dump

System, pressurizer spray, pressurizer PORVs, automatic rod control, or direct reactor trip on turbine trip.

The PSV 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 MSS pressures within 110 percent of the corresponding design pressure without a direct reactor trip on turbine trip.

6.3.6.2 Input Parameters and Assumptions

The loss-of-external electrical load/turbine trip accident is analyzed for three specific cases:

- Maximum RCS and secondary side pressures
- Minimum DNBR

The major assumptions used in the analyses are summarized below.

Initial Operating Conditions

The peak pressure cases are analyzed using the STDP. Initial reactor power and RCS temperatures are assumed to be at their nominal values plus uncertainties. Initial RCS pressure is assumed to be at its nominal value minus uncertainties. The analysis models thermal design flow (354,400 gpm).

The minimum DNBR case with pressure control is analyzed using the RTDP (Reference 3). Initial reactor power, pressure, and RCS average temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit. Minimum measured flow (364,700 gpm) is modeled.

Reactivity Coefficients

Minimum reactivity feedback (BOL) conditions are conservatively assumed for both cases. The analysis is performed at full-power conditions assuming an MTC of 0 pcm/°F. Least negative Doppler coefficients are also assumed.

Reactor Control

From the standpoint of the maximum pressures and minimum DNBR 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 insert prior to trip and reduce the severity of the transient.

Pressurizer Spray and PORVs

The pressurizer PORVs and pressurizer spray portion of the automatic pressure control system are assumed in the minimum DNBR and peak secondary side pressure cases since each serves to limit the RCS pressure increase, which is conservative for the DNBR and secondary side pressure calculations. In the peak RCS pressure case, the pressurizer PORVs and spray are assumed not to be available. In each case, safety valves are assumed operable with a capacity of 420,000 lbm/hr per valve for three valves.

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 AFW flow; however, eventually AFW flow would be initiated and a stabilized plant condition would be reached.

Reactor Trip

Reactor trip is actuated by the first RPS trip setpoint reached. Trip signals are expected due to high-pressurizer pressure, low-low steam generator level, and OTΔT.

Steam Release

No credit is taken for operation of the Steam Dump System or steam generator atmospheric relief valves (ARVs). This assumption maximizes secondary pressure.

6.3.6.3 Description of Analysis

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. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for AFW (except for long-term recovery) to mitigate the consequences of the transient.

A detailed analysis using the RETRAN (Reference 1) computer code was 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 spray, steam generators, MSSVs, and the Auxiliary Feedwater System (AFWS); and computes pertinent variables, including pressurizer pressure, steam generator pressure, steam generator mass, and reactor coolant average temperature.

6.3.6.4 Acceptance Criteria

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 ANS. The criteria are as follows.

- Pressure in the RCS and MSS shall remain below 110 percent of the design values.
- Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.
- An incident of moderate frequency shall not generate a more serious plant condition without other faults occurring independently. This criterion is met by ensuring that the pressurizer does not reach a water-solid condition. By precluding a water-solid condition, the potential for damage to the PSVs due to water relief is precluded and the RCS pressure boundary is uncompromised (that is, the Condition II event will not progress into a Condition III or IV type event).
- 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.

6.3.6.5 Results

The calculated sequence of events for the loss-of-external-electrical-load/turbine-trip cases are presented in Table 6.3-6.

Peak Pressure Cases

The transient responses for the total loss of steam load from full power are shown in Figures 6.3-33 through 6.3-36 for the peak RCS pressure case. No credit is taken for the pressurizer spray, pressurizer PORVs, or for the steam dump. The reactor is tripped by the high-pressurizer pressure trip channel. The PSVs are actuated and the primary system pressure remains below the 110-percent design value. In the peak secondary side pressure case, full credit is taken for the pressurizer spray and pressurizer PORVs, but no credit is taken for the steam dump. The reactor is tripped by the OTΔT reactor trip channel. The steam generator safety valves maintain the secondary side steam pressure below 110 percent of the steam generator shell design pressure. The peak primary system and secondary side steam pressures and the corresponding design pressures are presented in Table 6.3-18.

Minimum DNBR Case

The transient responses for the total loss of steam load from full power are shown in Figures 6.3-37 through 6.3-40. Full credit is taken for the pressurizer spray and pressurizer PORVs. No credit is taken for the steam dump. The reactor is tripped by the OTΔT reactor trip channel. The minimum DNBR remains well above the limit value, as demonstrated in Table 6.3-18.

6.3.6.6 Conclusions

The results of this analysis show that the plant design is such that a total loss-of-external-electrical-load transient without a direct reactor trip presents no hazard to the integrity of the RCS or the MSS at SPU conditions. All of the applicable acceptance criteria are met. The minimum DNBR for each case is greater than the safety analysis limit value. The peak primary and secondary system pressures remain below 110 percent of design at all times. The protection features presented in subsection 6.3.6.3 provide mitigation of the loss-of-external-electrical-load/turbine-trip transient so that the above criteria are satisfied.

6.3.7 Loss-of-Normal Feedwater

6.3.7.1 Introduction

An LONF (from pump failures, valve malfunctions, or LOAC) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, fuel 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. By precluding a water-solid condition in the pressurizer, the potential for damage to the pressurizer PORVs and safety valves due to water relief is precluded and the RCS pressure boundary is not compromised. 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 DNB condition.

The LONF that occurs as a result of the LOAC power is discussed in subsection 6.3.8 of this report.

The following events occur after the reactor trip for the LONF resulting from main feedwater pump failures or valve malfunctions:

- As steam system pressure rises following the trip, the steam generator atmospheric relief valves (ARVs) can be automatically opened. Steam dump to the condenser is assumed not available. If the steam generator ARVs are not available, the MSSVs can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor core.

- As the no-load temperature is approached, the steam generator ARVs (or the MSSVs, if the steam generator ARVs are not available) are used to dissipate the residual decay heat and RCP heat and to maintain the plant at the hot standby condition.

Following the occurrence of an LONF, the reactor can be tripped on any of the following RPS trip signals:

- Low-low water level in any steam generator
- OTΔT
- High-pressurizer pressure
- High-pressurizer water level
- RCP undervoltage (if coincident with a LOOP signal)
- Steam flow-feedwater flow mismatch in coincidence with low water level in any steam generator

AFW is supplied by the actuation of two motor-driven AFW pumps (MDAFWPs), which are initiated by any of the following signals:

- Low-low water level in any steam generator
- Automatic trip (not manual) of any main feedwater pump turbine
- Any safety injection (SI) signal
- Manual actuation
- LOOP concurrent with unit trip

In addition, one turbine-driven AFW pump (TDAFWP) starts on any of the following actuation signals, although no automatic delivery of water to the steam generators occurs (the TDAFWP is automatically started, but must be manually aligned by the operator to allow delivery of AFW flow to the steam generators).

- Low-low water level in any two steam generators
- Loss-of-offsite power (LOOP) concurrent with unit trip and no SI signal
- Manual actuation

The MDAFWPs are powered by the emergency diesel generators (EDGs). The pumps take suction from the condensate storage tank (CST) for delivery to the steam generators. Each MDAFWP is designed to supply the minimum required flow within 60 seconds of the initiating signal. The TDAFWP is valved out during normal operation. Therefore, although the TDAFWP is automatically actuated, this pump is not available to deliver flow to the steam generators until operator action is taken to align the TDAFWP.

Backup in equipment and control logic is provided to ensure that reactor trip and automatic AFW flow will occur following any LONF, including that followed by a LOAC. The analysis shows that following a LONF, the AFWS is capable of removing the stored and residual heat plus RCP heat, thus preventing overpressurization of the RCS and the steam generator secondary side, water relief from the pressurizer, and uncovery of the reactor core.

6.3.7.2 Input Parameters and Assumptions

The analysis was performed for IP3 at SPU conditions. The major assumptions used in this analysis were as follows.

- The plant is initially operating at 102 percent of the uprated NSSS power (3230 MWt) and bounds a nominal pump heat of 14 MWt.

- The RCPs are assumed to operate continuously throughout the transient providing a constant reactor coolant volumetric flow equal to the thermal design flow (TDF).

- Cases were considered assuming initial HFP T_{avg} at the upper and lower ends of the SPU operating range with uncertainty applied in both the positive and negative direction. The vessel average temperature assumed at the upper end of the range is 572°F with an uncertainty of ±7.5°F. The average temperature assumed at the lower end of the range is 549°F with an uncertainty of ±7.5°F. For each case, the initial pressurizer level is at the nominal programmed level plus 8.5-percent span.

- Initial pressurizer pressure is assumed to be 2250 psia with an uncertainty of ±60 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative direction to conservatively bound potential operating conditions.

- Cases are analyzed assuming initial feedwater temperatures at the upper and lower ends of the uprated operating feedwater temperature window (433.6°F and 390°F, respectively).

- Reactor trip occurs on steam generator low-low water level at 0-percent narrow range span (NRS).

- The worst single failure modeled in the analysis is the loss of one of the two MDAFWPs. This results in the availability of only one MDAFWP automatically supplying a minimum total AFW flow of 343 gpm, distributed equally between two of the four steam generators. Additional flow from the second MDAFWP or TDAFWP is assumed to be available only following operator action to start the second MDAFWP or to align the TDAFWP. This operator action is assumed to provide an additional 343 gpm of AFW flow distributed equally to the other two steam generators not receiving AFW automatically, and is assumed to occur at 10 minutes after the reactor trip due to a low-low steam generator water level signal.

- The automatic AFW flow is assumed to be initiated 60 seconds following a low-low steam generator water level signal.

- The pressurizer spray, PORVs, and heaters are assumed to be operable to maximize the pressurizer water volume. Note that these control systems are not required for event mitigation since the PSVs alone would prevent the RCS pressure from exceeding the design limit during this transient.

- Secondary system steam relief is achieved through the MSSVs, which are modeled assuming a +3-percent lift setpoint tolerance, a 5-psi ramp for the valve to pop open, and a pressure difference between each steam generator and the safety valves of approximately 20 psi at full relief flow. Steam relief through the steam generator ARVs and condenser dump valves is assumed unavailable.

- A conservative core decay heat generation based upon long-term operation at the initial power level preceding the trip is assumed. This core decay heat generation model is based on the 1979 version of ANS 5.1 (Reference 9) and includes a 2σ uncertainty. ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

- Analysis with both minimum (0 percent) and maximum (10 percent) SGTP is performed to conservatively bound potential operating conditions. In all cases, a nominal steam generator level plus a bounding uncertainty of 10-percent NRS was considered.

- A maximum AFW enthalpy of 90.77 Btu/lbm is conservatively assumed. An AFW line purge volume of 268.8 ft^3 is modeled.

6.3.7.3 Description of Analysis

A detailed analysis using the RETRAN (Reference 1) computer code was performed to determine the plant transient following a loss-of-normal feedwater. The code simulates the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and safety valves, pressurizer heaters and spray, steam generators, MSSVs, and the AFWS, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

6.3.7.4 Acceptance Criteria

Based on its frequency of occurrence, the LONF accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event.

- The critical heat flux shall not be exceeded. This is demonstrated by ensuring that the applicable safety analysis DNBR limit is met. With respect to DNB, the LONF accident is bounded by the LOL accident described in subsection 6.3.6. Both of these events represent a reduction in the heat removal capability of the secondary system. For the LONF event, the RCS temperature increases gradually as the steam generators boil down to the low-low level trip setpoint, at which time reactor trip occurs, followed by turbine trip. For the LOL event, the turbine trip is the initiating event, and the loss-of-heat sink is much more severe. Therefore, the initial RCS heatup will be much more severe for the loss-of-load event than for the LONF event, and the LOL event will always be more severe with respect to the minimum DNBR criterion.

- Pressure in the RCS and MSS shall be maintained below 110 percent of the design pressures. With respect to RCS and MSS overpressurization, the LONF accident is bounded by the loss-of-load accident reported in subsection 6.3.6. For the loss-of-normal-feedwater event, turbine trip occurs after reactor trip, whereas for the loss-of-load the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the LOL than for the LONF.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. This criterion is met by ensuring that the pressurizer does not reach a water-solid condition. By precluding a water-solid condition in the pressurizer, the potential for damage to the pressurizer PORVs and safety valves due to water relief is precluded and the RCS pressure boundary is not compromised (that is, the Condition II event will not progress into a Condition III or IV type event).

6.3.7.5 Results

The calculated sequence of events for this accident is listed in Table 6.3-7. Figures 6.3-41 through 6.3-49 present the transient response of plant conditions and parameters of interest following a LONF with the assumptions listed in subsection 6.3.7.2 of this document. It should be noted that the transient is initiated following a 20-second steady-state.

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 MSSVs continues to dissipate the stored and generated heat. Approximately 1 minute following the initiation of the low-low steam generator water level trip, one MDAFWP starts automatically, consequently reducing the rate at which the steam generator water level decreases in the two steam generators receiving automatic AFW flow. Operator action to start the second MDAFWP or to align the TDAFWP at 10 minutes after reactor trip on a low-low steam generator water level signal is assumed to deliver additional AFW flow to the two steam generators not already receiving AFW and the plant is brought to a stable condition.

The pressurizer never reaches a water-solid condition, as demonstrated in Table 6.3-18 (see Figure 6.3-42). Hence, no water relief from the pressurizer occurs.

Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

6.3.7.6 Conclusions

With respect to DNB, the LONF accident is bounded by the LOL accident (see subsection 6.3.6), which demonstrates that the minimum DNBR remains greater than the safety analysis limit.

With respect to RCS and MSS pressurization, the LONF accident is bounded by the LOL accident (see subsection 6.3.6), which demonstrates that the RCS and MSS pressure limits are met.

The results of the analysis show that the pressurizer does not reach a water-solid condition and therefore, the LONF event does not adversely affect the core, RCS, or MSS.

6.3.8 LOAC to the Station Auxiliaries

6.3.8.1 Introduction

A complete loss-of-non-emergency-AC power can result in the loss-of-all-power to the plant auxiliaries, such as the RCPs and condensate pumps. The loss-of-power to the condensate pumps results in a LONF. The loss of power may be caused by a complete loss-of-the-offsite grid accompanied by a turbine generator trip at the station, or by a loss-of-the-onsite AC (LOAC) distribution system.

The first few seconds of the transient would be almost identical to the complete loss-of-flow accident presented later in subsection 6.3.13, in which the pump coastdown inertia along with the reactor trip prevents reaching the DNBR limit. After the trip, decay heat removal will be accommodated by the AFWS. This portion of the transient would be similar to that presented in subsection 6.3.7 for the LONF event.

Following a LOAC with turbine and reactor trips, the sequence described below will occur.

- Plant vital instruments are supplied from emergency DC power sources.

- As the steam system pressure rises following the trip, the steam generator ARVs can be automatically opened to atmosphere. The condenser is assumed not available for steam dump because of the loss-of-the-circulating water pumps. If the steam generator ARVs are not available, the MSSVs can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- As the no-load temperature is approached, the steam generator ARVs (or the MSSVs, if the steam generator ARVs are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot standby condition.

- The EDGs will start on a loss-of-voltage on the plant emergency buses and begin to supply plant vital loads.

The AFWS is started automatically as discussed previously in subsection 6.3.7 for the LONF analysis. The AFWS comprises two MDAFWPs and 1 TDAFWP. The TDAFWP uses steam from the secondary system and exhausts the steam to the atmosphere. The two MDAFWPs are supplied by power from the EDGs and take suction directly from the CST for delivery to the steam generators. Each MDAFWP is designed to supply the minimum required flow within 60 seconds of the initiating signal, even if a loss of all non-emergency-AC power occurs simultaneously with a LONF. The TDAFWP is started automatically. However, the TDAFWP needs to be manually aligned before AFW flow can be delivered to the steam generators.

Following the loss-of-power to the RCPs, the RCPs coast down and the removal of residual decay heat is provided by natural circulation in the RCS, supported by AFW flow to the secondary system. Demonstrating that acceptable results can be obtained for this event shows that the natural circulation flow in the RCS is adequate to remove decay heat from the core.

The analysis of the LOAC event is performed to demonstrate that natural circulation in the RCS, along with the AFWS, is capable of removing the stored and residual decay heat from the core, and consequently preventing RCS or MSS overpressurization, water relief from the pressurizer, and uncovery of the reactor core.

6.3.8.2 Input Parameters and Assumptions

The analysis was performed for IP3 at SPU conditions. The major assumptions used in this analysis were as follows.

- The plant is initially operating at 102 percent of the uprated NSSS power (3230 MWt). A conservative RCP heat was assumed for the period of the event prior to the tripping of the RCPs.

- The initiating event is a loss-of-all-non-emergency-AC power that results in a loss-of-power to the condensate pumps. The loss of the condensate pumps results in a LONF.

- The RCPs are conservatively assumed to operate until the time of reactor trip, providing a constant reactor coolant volumetric flow equal to the TDF value. This assumption maximizes the amount of stored energy in the RCS. The loss-of-power to the RCPs is not assumed to occur until 2 seconds after the start of rod motion following the reactor trip on a low-low steam generator water level condition.

- No credit is taken for the immediate insertion of the control rods due to the LOAC to the station auxiliaries.

- Cases were considered assuming initial HFP T_{avg} at the upper and lower ends of the SPU operating range with uncertainty applied in both the positive and negative direction. The vessel average temperature assumed at the upper end of the range is 572°F with an uncertainty of ±7.5°F. The average temperature assumed at the lower end of the range is 549°F with an uncertainty of ±7.5°F. For each case, the initial pressurizer level is at the nominal programmed level plus 8.5-percent span.

- Initial pressurizer pressure is assumed to be 2250 psia with an uncertainty of ±60 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative direction to conservatively bound potential operating conditions.

- Cases are analyzed assuming initial feedwater temperatures at the upper and lower ends of the uprated operating feedwater temperature window (433.6 and 390°F, respectively).

- Reactor trip occurs on steam generator low-low water level at 0 percent of NRS.

- The worst single failure modeled in the analysis is the loss of one of the two MDAFWPs. This results in the availability of only one MDAFWP automatically supplying a minimum total AFW flow of 343 gpm, distributed equally between two of the four steam generators. Additional flow from the second MDAFWP or TDAFWP is assumed to be available only following operator action to start the second MDAFWP or to align the TDAFWP. This operator action is assumed to provide an additional 343 gpm of AFW flow distributed equally to the other two steam generators not receiving AFW automatically, and is assumed to occur at 10 minutes after the reactor trip due to a low-low steam generator water level signal.

- The automatic AFW flow is assumed to be initiated 60 seconds after a low-low steam generator water level signal.

- The pressurizer spray, PORVs, and heaters are assumed to be operable to maximize the pressurizer water volume. Note that these control systems are not required for event mitigation since the PSVs alone would prevent the RCS pressure from exceeding the design limit during this transient.

- Secondary system steam relief is achieved through the MSSVs, which are modeled assuming a +3 percent lift setpoint tolerance, a 5-psi ramp for the valve to pop open, and a pressure difference between each steam generator and the safety valves of approximately 20 psi at full relief flow. Steam relief through the steam generator ARVs or condenser dump valves is assumed unavailable.

- A conservative core decay heat generation based upon long term operation at the initial power level preceding the trip is assumed. This core decay heat generation model is based on the 1979 version of ANS 5.1 (Reference 9) and includes a 2σ uncertainty. ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

- Analysis with both minimum (0 percent) and maximum (10 percent) SGTP is performed to conservatively bound potential operating conditions. In all cases, a nominal steam generator level plus a bounding uncertainty of 10-percent NRS was considered.

- A maximum AFW enthalpy of 90.77 Btu/lbm is conservatively assumed. An AFW line purge volume of 268.8 ft^3 is modeled.

6.3.8.3 Description of Analysis

A detailed analysis using the RETRAN (Reference 1) computer code was performed to determine the plant transient following a LOAC. The code simulates the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and safety valves, pressurizer heaters and spray, steam generators, MSSVs, and the AFWS, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

6.3.8.4 Acceptance Criteria

Based on its frequency of occurrence, the loss-of-non-emergency-AC-power accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event.

- The critical heat flux shall not be exceeded. This is demonstrated by ensuring that the applicable safety analysis DNBR limit is met. With respect to DNB, the loss-of-non-emergency-AC-power accident is bounded by the complete loss-of-flow accident reported in subsection 6.3.13. The DNBR consequences of the loss-of-non-emergency-AC-power event are similar to those of the LONF event, with the additional effect of a reduction in the core flow rate caused by loss-of-power to the RCPs. However, the loss-of-non-emergency-AC-power event remains bounded by the complete-loss-of-flow event. This is because the RCP coastdown is the initiating fault and the reactor trip occurs when the core flow is already degraded.

- Pressure in the RCS and MSS shall be maintained below 110 percent of the design pressures. With respect to RCS and MSS overpressurization, the loss-of-non-emergency-AC-power accident is bounded by the loss-of-load accident reported earlier in subsection 6.3.6. For the loss-of-non-emergency-AC-power event, turbine trip occurs after reactor trip, whereas for loss-of-load the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the LOL than the loss-of-non-emergency-AC-power.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. This criterion is met by ensuring that the pressurizer does not reach a water-solid condition. By precluding a water-solid condition in the pressurizer, the potential for damage to the pressurizer PORVs and safety valves due to water relief is precluded and the RCS pressure boundary is not compromised (that is, the Condition II event will not progress into a Condition III or IV type event).

6.3.8.5 Results

Figures 6.3-50 through 6.3-58 present the transient response of plant conditions and parameters of interest following a loss of non-emergency AC power with the assumptions listed earlier in subsection 6.3.8.2. The calculated sequence of events for this accident is listed in Table 6.3-8. It should be noted that the transient is initiated following a 20-second steady-state.

During the first few seconds after the loss-of-non-emergency-AC power to the RCPs, the RCS flow transient closely resembles the complete loss-of-flow incident, where core damage due to rapidly increasing core temperature is prevented by reactor trip, which, for a loss-of-non-emergency-AC-power event, is on a low-low steam generator water level signal. After reactor trip, stored and residual decay heat must be removed to prevent damage to the core and the RCS and MSS. The RETRAN code results show that natural circulation and the AFW flow available are sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

The pressurizer never reaches a water-solid condition, as demonstrated in Table 6.3-18 (see Figure 6.3-51). Hence, no water relief from the pressurizer occurs.

6.3.8.6 Conclusions

With respect to DNB, the loss-of-non-emergency-AC-power event is bounded by the complete-loss-of-flow event (see subsection 6.3.13), demonstrating that the minimum DNBR remains above the safety analysis limit.

With respect to RCS and MSS pressurization, the loss-of-non-emergency-AC-power accident is bounded by the LOL accident (see subsection 6.3.6), which demonstrates that the RCS and MSS pressure limits are met.

The results of the analysis show that the pressurizer does not reach a water-solid condition and therefore, the LOAC does not adversely affect the core, the RCS, or the MSS.

6.3.9 Excessive Heat Removal Due to Feedwater System Malfunctions

6.3.9.1 Introduction

Reductions in feedwater temperature or excessive feedwater additions are a 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, OTΔT, and OPΔT trips) prevent any power increase that could lead to a DNBR that is less than the safety analysis 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 can cause a decrease in RCS temperature and thus, a positive reactivity insertion due to the effects of the negative MTC 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. However, the low-pressure feedwater bypass valve is not in service. Thus, this event is no longer credible and was not considered here.

6.3.9.2 Input Parameters and Assumptions

The reactivity insertion rate following a feedwater system malfunction, attributed to the cooldown of the RCS, was calculated with the following assumptions:

- This accident is analyzed with the RTDP as described in WCAP-11397 (Reference 3). 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 (MMF) is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in WCAP-11397 (Reference 3).

- The analyses are done at the uprated NSSS power level of 3230 MWt.

- For the feedwater control valve accident at full-power conditions that results in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction, resulting in a step increase to 143 percent of the nominal full-power feedwater flow to one steam generator.

- 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 HFP cases, a 20°F decrease in the feedwater temperature is assumed to occur coincident with the feedwater flow increase.

- For the feedwater control valve accident at zero-load conditions that results in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction, resulting in a step increase to 210 percent of the nominal full-load value for one steam generator.

- For cases at zero-load conditions, feedwater temperature is assumed to be 70°F.

- The initial water level in all the steam generators is a conservatively low level; 35-percent NRS for full-power conditions and 45-percent NRS for zero-power conditions.

- No credit is taken for the heat capacity of the RCS and steam generator metal mass in attenuating the resulting plant cooldown.

- 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 RPS features, including power-range high neutron flux, OTΔT, 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 (for example, SI) are not assumed to function. The RPS can 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.

6.3.9.3 Description of Analysis

The excessive heat removal due to a feedwater system malfunction transient was analyzed with the RETRAN (Reference 1) computer code. This code simulates a multi-loop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computed pertinent plant variables including temperatures, pressures, and power level.

The excessive-feedwater-flow event assumed 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 assumed a conservatively large moderator density coefficient characteristic of EOL conditions.

6.3.9.4 Acceptance Criteria

Based on its frequency of occurrence, the feedwater-system-malfunction event is considered a Condition II event as defined by the 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 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 RCS and MSS should be maintained below 110 percent of the design pressures.
- The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

6.3.9.5 Results

The excessive-feedwater-flow full-power case with automatic rod control yielded results that were nearly identical to the case assuming manual rod control. Considering cases with and without automatic rod control and presenting the more limiting results demonstrated that the Rod Control System was not required to function for this event. A turbine trip, which resulted in a reactor trip, was actuated when the steam generator water level in the affected steam generator reached the high-high water level setpoint. The results presented are for the case that assumes the Rod Control System was in manual operational mode.

The case initiated at HZP conditions assumed manual rod control and was less limiting than the HZP steamline break analysis. Therefore, the results of the HZP case are not presented.

For all cases of excessive feedwater flow, continuous addition of cold feedwater was 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 subsection 6.3.6 (loss-of-external-electrical-load and/or turbine trip). With the reactor 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 6.3-9 shows the time sequence of events for the HFP feedwater malfunction transient. Figures 6.3-59 through 6.3-62 show transient responses for various system parameters during a feedwater system malfunction initiated from HFP conditions with manual rod control. The minimum DNBR remains above the safety analysis limit at all times, as demonstrated in Table 6.3-18.

6.3.9.6 Conclusions

For the excessive-feedwater-addition-at-power transient, the results showed that the DNBRs encountered were above the limit value; hence, no fuel damage was predicted.

The protection features presented previously in subsection 6.3.9.2 provided mitigation of the feedwater-system-malfunction transient so that the above criteria were satisfied.

6.3.10 Excessive Load Increase Incident

6.3.10.1 Introduction

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 RCS is designed to accommodate a 10-percent step-load increase or a 5-percent-per-minute ramp-load increase in the range of 15 to 100 percent of full power, taking credit for all control systems in automatic. Any loading rate in excess of these values can cause a reactor trip actuated by the RPS.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control. For excessive loading by the operator or by system demand, the turbine load limiter keeps the maximum turbine load at 100-percent rated load.

During power operation, steam dump to the condenser is controlled by comparing the RCS temperature (nominal T_{avg}) to a reference temperature based on turbine power, where a high temperature difference in conjunction with a loss of load or a turbine trip indicates a need for steam dump. A single controller or control signal 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 LOL signals are developed by independent sensors.

Protection against an excessive load increase accident is provided by the following RPS signals:

- OPΔT
- OTΔT
- Power range high neutron flux
- Low-pressurizer pressure

6.3.10.2 Input Parameters and Assumptions

The analysis includes the following conservative assumptions:

- This event is evaluated with the RTDP (Reference 3). Initial reactor power and RCS pressure and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-11397-P-A (Reference 3).

- The evaluation is performed for a step-load increase of 10-percent steam flow from 100-percent RTP.

- The excessive load increase event is evaluated for both BOL (minimum reactivity feedback) and EOL (maximum reactivity feedback) conditions.

6.3.10.3 Description of Analysis

Four cases were considered to demonstrate that the fuel cladding integrity will not be adversely affected following a 10-percent step-load increase from rated load. This was shown by demonstrating that the minimum DNBR would not go below the safety analysis limit value.

- Manually controlled reactor with BOL (minimum moderator) reactivity feedback
- Manually controlled reactor with EOL (maximum moderator) reactivity feedback
- Automatically controlled reactor with BOL (minimum moderator) reactivity feedback
- Automatically controlled reactor with EOL (maximum moderator) reactivity feedback

At BOL minimum moderator feedback conditions, the core had the least-negative MTC of reactivity and the least-negative Doppler-only power coefficient curve, and therefore, the least-inherent transient response capability. Since a positive MTC would provide a transient benefit, a zero MTC was evaluated for the minimum feedback conditions. For the EOL maximum moderator feedback conditions, the MTC of reactivity had its most-negative value and the most-negative Doppler-only power coefficient curve. This resulted in the largest amount of reactivity feedback due to changes in coolant temperature.

The effect of this transient on the minimum DNBR was evaluated by applying conservatively large deviations to the initial conditions of core power, average coolant temperature, and pressurizer pressure at the normal full-power operating conditions to generate a limiting set of statepoints. These deviations bound the variations that could occur as a result of an excessive load increase accident and were only applied in the direction that had the most adverse effect on the DNB ratio; namely increased power, coolant temperature, and decreased pressure. No credit was taken for the decrease in coolant temperature and no reactor trip is assumed.

The reactor condition statepoints (temperature, pressure, and power) were compared to the conditions corresponding to operation at the safety analysis DNB limit.

Normal reactor control systems and engineered safety systems were not required to function. A conservative limit on the turbine valve opening was assumed. The analysis did not take credit for pressurizer heaters.

The RPS was assumed to be operable. However, reactor trip was not encountered for most cases due to the error allowances assumed in the setpoints. No single active failure in any system or component required for mitigation will adversely affect the consequences of this accident.

6.3.10.4 Acceptance Criteria

Based on its frequency of occurrence, the excessive load increase event is considered a Condition II event as defined by the ANS. Even though DNB is the primary concern in the evaluation of the excessive load increase, the following three items summarize the criteria associated with this transient:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures. With respect to RCS and MSS overpressurization, the excessive load increase incident is bounded by the loss-of-load accident reported earlier in subsection 6.3.6. Although RCS pressure may increase slightly for excessive load increase cases with automatic rod control, the pressurizer PORVs would have sufficient capacity to limit pressurization at or very near the opening setpoint. If the pressurizer PORVs were not available and pressure continued to rise, the pressurizer safety valves would have more than enough capacity to limit further pressurization significantly above the valve opening pressure. Steam generator pressure decreases as a result of the excessive load increase incident and therefore MSS overpressurization is not a concern.

- The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt. The overpower limit (120-percent) is also not violated during the excessive load increase incident, as a 10-percent mismatch in primary/secondary load does not cause a 20-percent increase in core power, even with a conservative rod control model.

6.3.10.5 Results

An excessive load increase accident of the magnitude considered here does not result in reactor trip, and the plant soon reaches a new equilibrium condition at a higher power level based on the increased steam load. Transients assuming manual rod control yield decreased coolant temperatures and pressures resulting from increased heat removal.

A comparison of the plant conditions assuming conservatively bounding deviations in core power, average coolant temperature, and pressure to the conditions corresponding to operation at the safety analysis DNB limit indicated that the minimum DNBR remained above the limit value for each of the cases, as demonstrated in Table 6.3-18.

RCS and MSS overpressurization are not a concern for this transient.

6.3.10.6 Conclusions

It has been demonstrated that for an excessive load increase, the minimum DNBR during the transient will not go below the safety analysis limit value and thus will neither affect fuel cladding integrity nor result in the release of fission products to the RCS.

6.3.11 Rupture of a Steam Pipe

6.3.11.1 Introduction

A steam pipe rupture is assumed to include any accident that results in an uncontrolled steam release from a steam generator. The release can occur as a result of a break in a pipe line or a valve malfunction. The steam release results in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The removal of energy from the RCS causes a reduction of coolant temperature and pressure. With a negative MTC, the cooldown results in a reduction of core shutdown margin. If the most reactive control rod is assumed to be stuck in its fully withdrawn position, there is a possibility that the core can become critical and return to power even with the remaining control rods inserted. A return to power following a steam pipe rupture is a potential problem only because of the high hot-channel factors that can exist when the most reactive rod is assumed stuck in its fully withdrawn position. Even if the most pessimistic combination of circumstances that could lead to power generation following a steamline break was assumed, the core is ultimately shut down by the boric acid in the SIS.

The analysis of a steam pipe rupture was made to show that assuming the most reactive RCCA stuck in its fully withdrawn position and assuming the worst single failure in the engineered safety features (ESFs), the core cooling capability could be maintained and that offsite doses would not exceed applicable limits. In addition, the analysis considers conditions both with and without offsite power available.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis showed that DNB did not occur, thus ensuring clad integrity.

The following systems provide the necessary protection against a steam pipe rupture:

- SIS actuation from any one of the following:
  - — Two-out-of-3 channels of low pressurizer pressure signals
  - — Two-out-of-3 high differential pressure signals between steamlines
  - — High steam flow in 2-out-of-4 lines (1-out-of-2 per line) in coincidence with either low RCS average temperature (2-out-of-4) or low steamline pressure (2-out-of-4)
  - — Two-out-of-3 high containment pressure signals
  - — High-high containment pressure (two sets of 2-out-of-3)
  - — Manual actuation
- The overpower reactor trips (nuclear flux and ΔT) and the reactor trip occurring upon actuation of the SIS.
- Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown. However, in addition to the normal control action that will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves (including the motor-operated block valves and low-flow bypass valves) and close the feedwater pump discharge valves, which in turn would trip the main feedwater pumps.
- Closing the fast-acting steamline stop valves (designed to close in less than 5 seconds) on:
  - — High steam flow in 2-out-of-4 lines (1-out-of-2 per line) in coincidence with either low RCS average temperature (2-out-of-4) or low steamline pressure (2-out-of-4)
  - — High-high containment pressure (two sets of 2-out-of-3).

Each main steamline has a fast-closing stop valve and a check valve. These eight valves prevent blowdown of more than one steam generator for any MSLB location even if one valve fails to close. For example, for a MSLB upstream of the stop valve in one line, a closure of either the check valve in that line or the stop valves in the other lines will prevent blowdown of the other steam generators.

For breaks downstream of the isolation valves, closure of all valves will completely terminate the blowdown. For any main steamline break, in any location, no more than one steam generator would experience an uncontrolled blowdown even if one of the isolation valves fails to close.

The effective throat area of the steam generator flow restrictor nozzles is bounded by 1.4 ft^2. These flow areas are considerably less than the main steam pipe area. Thus, the flow restrictor nozzles serve to limit the maximum steam flow for a break at any location.

6.3.11.2 Input Parameters and Assumptions

The following conditions are assumed to exist at the time of a MSLB accident.

EOL shutdown margin at no-load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position are all assumed. Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steamline break accident will not lead to a more adverse condition than the case analyzed.

The negative moderator coefficient corresponds to an EOL rodded core with the most-reactive RCCA withdrawn. The variation of the coefficient with temperature and pressure is included. The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector are conservatively combined to obtain average core properties for reactivity feedback calculations. Furthermore, it is conservatively assumed that the core power distribution was uniform. These two conditions cause an underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity and power distribution is checked for the limiting statepoints for the cases analyzed.

This core analysis considers the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution, and non-uniform core inlet temperature effects. For cases in which steam generation occurred in the high flux regions of the core, the effect of void formation is also included. It was determined that the reactivity used in the kinetics analysis was always larger than the reactivity calculated, including the above local effects for the statepoints. These results verified conservatism, that is, an underprediction of negative reactivity feedback from power generation.

Minimum capability for injection of high-concentration boric acid (2400 ppm) solution corresponding to the most restrictive single failure in the High-Head Safety Injection System (HHSIS) is assumed. The Emergency Core Cooling System (ECCS) consists of three systems:

the passive accumulators, the Residual Heat Removal System (RHRS), and the HHSIS. Only the accumulators and HHSIS are modeled for the steamline break accident analysis.

The actual modeling of the accumulators and HHSIS in RETRAN is described in WCAP-14882-P-A (Reference 1). A conservative flow is modeled in the analysis for the HHSIS that reflects a composite modeling of the minimum SI flow resulting from either a failure of one train of the HHSIS or a failure of a cold-leg branch line motor-operated valve (MOV). No credit is taken for the low-concentration borated water, which must be swept from the lines downstream of the RWST prior to the delivery of concentrated boric acid to the RCLs.

For the case in which offsite power is assumed, the sequence of events in the HHSIS is the following. After the generation of the SI signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves began to operate and the HHSI pumps started. In 12 seconds, the valves are assumed to be in the final position and the pump is assumed to be at full speed. In cases where offsite power is not available, an additional 10-second delay is assumed to start the diesels and load the necessary SI equipment onto them.

Design value of the steam generator heat transfer coefficient including allowance for fouling factor is assumed.

Since the steam generators have integral flow restrictors bounded by a 1.4 ft^2 throat area, any rupture with a break area greater than the area of the flow restrictor, regardless of the location, would have the same effect on the NSSS as the break equal to the area of the flow restrictor. The following cases were considered in determining the core power and RCS transients.

Case 1: Complete severance of a pipe, with the plant initially at no-load conditions, and full reactor coolant flow with offsite power available.

Case 2: Case 1 with LOOP coincident with the steamline break. LOOP results in RCP coastdown, which was assumed to begin at 3 seconds.

Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return-to-power phase following the steamline break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend on the core conditions for power, temperature, pressure, and flow, and thus are different for each case studied.

The core conditions used for both with and without offsite power cases correspond to values determined from the respective transient analyses.

Both cases assumed hot shutdown conditions at event initiation since this represents the most conservative initial condition. These hot shutdown initial conditions are considered for cases assuming full-power operation at HFP high T_{avg} of 572°F. Should the reactor be just critical or operating at power at the time of a steamline break, the reactor would be tripped by the normal Overpower Protection System when the power level reaches a trip setpoint. Following a trip at power, the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steamline break before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy is removed, the cooldown and reactivity insertions proceeded in the same manner as in the analysis, which assumes no-load conditions at time zero. In addition, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steamline breaks occurring at power.

Perfect moisture separation in the steam generator is assumed.

6.3.11.3 Description of Analysis

The double-ended rupture of a major steamline is the most-limiting cooldown transient. It was analyzed at zero power with no decay heat since decay heat would retard the cooldown, thereby reducing the return to power.

The analysis of the steam pipe break was performed to determine:

- The core heat flux and RCS temperature and pressure resulting from the cooldown following the steamline break. The RETRAN code (Reference 1) was used to calculate the transient conditions.

- The thermal-hydraulic behavior of the core following a steamline break. A detailed thermal-hydraulic digital computer code, VIPRE, was used to determine if DNBR fell below the safety analysis limit for the core conditions computed in the above bulleted paragraph.

6.3.11.4 Acceptance Criteria

A main steamline break is classified as an ANS Condition IV event, a limiting fault. Condition IV occurrences are faults that are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. Condition IV faults are not to cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of the guideline values presented in 10CFR100. However, the main steamline break transient is conservatively analyzed to the applicable Condition II criteria, demonstrating that the DNB design basis is satisfied. Therefore, the analysis presented in this section conservatively meets the radiological dose criteria set forth for a steamline break. Also, the effects of minor steamline breaks, which are classified as Condition II events, are bounded by the analysis presented in this section.

6.3.11.5 Results

The calculated sequences of events for both cases are shown in Table 6.3-10.

The results presented were a conservative indication of the events that would occur assuming a steamline break, since it is postulated that all of the conditions described above occur simultaneously.

Conservatively assuming a stuck RCCA with or without offsite power, and assuming a single failure in the ESFs, the core remained in place and intact. Although DNB and possible clad perforation are not necessarily unacceptable following a steam pipe break, the analysis in fact shows that the DNBR never falls below the safety analysis limit for any break assuming the most reactive assembly stuck in its fully withdrawn position, as demonstrated in Table 6.3-18. By meeting the DNB design basis criterion, this analysis also conservatively meets the radiological dose criteria set forth for a steamline break.

Core Power and RCS Transient

Figure 6.3-63 shows the core heat flux and core reactivity following a MSLB (complete severance of a steam pipe) at initial no-load conditions. Figure 6.3-64 shows the corresponding vessel inlet temperature and pressurizer pressure after the break occurs. Figure 6.3-65 shows steam flow and steam generator mass of the faulted and intact steam generators during the event. Offsite power was assumed available so that full reactor coolant flow existed. The transient shown assumed an uncontrolled steam release from only one steam generator. Should the core be critical at near-zero power when the break occurs, the initiation of SI by low-pressurizer pressure or high steam flow coincident with either low RCS average temperature or low steamline pressure will trip the reactor. Steam release from more than one steam generator will be prevented by automatic closure of the fast-acting isolation valves in the steamlines by high steam flow coincident with either low RCS average temperature or low steamline pressure. Even with the failure of one valve, release is limited to no more than approximately 27 seconds for the other steam generators while the one generator blows down. The steamline stop valves are designed to be fully closed in less than 5 seconds from receipt of a closure signal.

The core attained criticality with the RCCAs inserted (with the design shutdown assuming one stuck RCCA) before boron solution at 2400 ppm entered the RCS. A peak core power lower than the nominal full-power value was attained.

The calculation assumed the boric acid was mixed with, and diluted by, the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depended upon the relative flow rates in the RCS and in the HHSIS. The variation of mass flow rate in the RCS due to water density changes was included in the calculation as is the variation of flow rate in the HHSIS due to changes in the RCS pressure. The HHSIS flow calculation included the line losses in the system as well as the pump head curve. Figure 6.3-66 illustrates the core averaged boron concentration during the event.

For the case assuming coincidental LOOP when the SI signal is generated, the SIS delay time included 10 seconds to start the diesel, in addition to the 12 seconds to start the SI pump and open the valves. Criticality was achieved later, and the core power increase was slower, than in the case with offsite power available. The ability of the emptying steam generator to extract heat from the RCS was reduced by the decreased flow in the RCS. The peak power remained well below the nominal full-power value.

It should be noted that following a main steamline break, only one steam generator blows down completely. Thus, the remaining steam generators were still available for dissipation of decay heat after the initial transient was over. In the case with LOOP, this heat was removed to the atmosphere via the steamline safety valves.

Margin to Critical Heat Flux

DNB analyses were performed for the most conservative of the two analyzed cases, that is, the case with offsite power. The minimum DNBR was greater than the safety analysis limit value.

6.3.11.6 Conclusions

The analysis showed that the acceptance criteria stated earlier in subsection 6.3.11.4 were satisfied. Although DNB and possible cladding perforation following a steam pipe break were not necessarily unacceptable and not precluded by the criteria, the above analysis showed that the DNBR never fell below the safety analysis limit.

6.3.12 Partial Loss-of-Reactor-Coolant Flow

6.3.12.1 Introduction

A partial loss-of-forced-reactor-coolant-flow accident can result from a mechanical or electrical failure in an 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 is a rapid increase in coolant temperature. This increase in coolant temperature could result in DNB, with subsequent fuel damage, if the reactor is not promptly tripped.

The reactor trip on low reactor coolant flow provides protection against partial loss-of-flow conditions. This function is generated by 2-out-of-3 low-flow signals per RCL. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip.

6.3.12.2 Input Parameters and Assumptions

This accident is analyzed using the RTDP (Reference 3). Initial core power (consistent with SPU conditions) and reactor coolant pressure are assumed to be at their nominal values for steady-state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the high T_{avg} program. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 3). MMF is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used along with the most positive MTC limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached.

A conservatively low trip reactivity value (4.0-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position is modeled in addition to a conservative rod drop time (2.7 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the RSAC verification process.

In addition, a 0.85-percent core flow penalty is modeled to account for RCS loop-to-loop flow asymmetry.

Normal reactor control systems and engineered safety systems (for example, SI) 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.

6.3.12.3 Description of Analysis

A partial loss-of-flow involving the loss of one RCP with four loops in operation was analyzed for the SPU conditions.

The transient was analyzed using two computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE computer code (Reference 8) was then used to calculate the hot channel heat flux transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR transient presented was based on the minimum of the typical and thimble cells.

6.3.12.4 Acceptance Criteria

A partial loss-of-forced-reactor-coolant-flow incident is classified by the ANS as a Condition II event. The immediate effect is a rapid increase in reactor coolant temperature and subsequent increase in RCS pressure. The primary acceptance criterion for this event is that the critical heat flux should not be exceeded. This was ensured by demonstrating that the minimum DNBR did not go below the applicable safety analysis limit at any time during the transient. The analysis results also demonstrated that pressure in the RCS and MSS remained below 110 percent of the respective design pressures to ensure that the applicable Condition II pressure criteria were met.

6.3.12.5 Results

The partial loss-of-forced-reactor-coolant-flow event was the least DNB-limiting transient among all loss-of-flow cases. Reactor trip for the partial loss-of-flow case occurred on a low primary coolant flow signal. The VIPRE analysis confirmed that the minimum DNBR was greater than the safety analysis limit. Fuel clad damage criteria were not challenged in the partial loss-of-forced-reactor-coolant-flow event since the DNB criterion was met, as demonstrated in Table 6.3-18.

The analysis of the partial loss-of-flow event also demonstrated that the peak RCS and MSS pressures were well below their respective limits.

The sequence of events for the partial loss-of-flow transient is presented in Table 6.3-11. The transient results for this case are presented in Figures 6.3-67 through 6.3-69.

6.3.12.6 Conclusions

The analysis performed at SPU conditions demonstrated that, for the partial loss-of-flow incident, the DNBR did not decrease below the safety analysis limit at any time during the transient; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remained below their respective limits at all times. All applicable acceptance criteria were therefore met.

6.3.13 Complete Loss-of-Reactor-Coolant Flow

6.3.13.1 Introduction

A complete loss-of-forced-reactor-coolant-flow accident can result from simultaneous loss of electrical power or a reduction in supply frequency to all RCPs. If the reactor is at power at the time of the event, the immediate effect is a rapid increase in coolant temperature. This increase in coolant temperature could result in DNB, 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 voltage or low frequency on pump power supply bus (above Permissive P-7).
- Low reactor coolant flow (1-out-of-4 above Permissive P-8, 2-out-of-4 above Permissive P-7).
- RCP circuit breakers opening (1-out-of-4 above Permissive P-8, 2-out-of-4 above Permissive P-7).

The reactor trip on RCP undervoltage protects against conditions that can cause a loss of voltage to all RCPs, that is, LOOP. The reactor trip on RCP underfrequency is provided to protect against frequency disturbances on the power grid.

The reactor trip on low primary coolant loop flow provides protection against loss-of-flow conditions that affect individual RCLs and serves as a backup for the undervoltage and underfrequency trip functions. The reactor trip on low primary coolant loop flow is generated by 2-out-of-3 low-flow signals per RCL. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10-percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip.

6.3.13.2 Input Parameters and Assumptions

This accident is analyzed using the RTDP (Reference 3). Initial core power (consistent with uprated power conditions) and reactor coolant pressure are assumed to be at their nominal values for steady-state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the high T_{avg} program. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 3). MMF is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used along with the most positive (MTC) limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR was reached.

A conservatively low trip reactivity value (4.0-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position is modeled in addition to a conservative rod drop time (2.7 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the RSAC verification process.

Normal RCS and engineered safety systems (for example, SI) 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.

6.3.13.3 Description of Analysis

The following complete loss-of-forced-reactor-coolant-flow cases were analyzed for the SPU.

- Complete loss-of-flow transient due to a complete loss of power to all RCPs with four loops in operation

- Complete loss-of-flow transient due to an underfrequency condition

Case 1 assumed that the RCPs begin to coast down upon reaching an undervoltage trip setpoint (modeled to occur at t = 0 seconds in this analysis). Rod motion following the undervoltage trip was modeled to occur at t = 1.5 seconds, reflecting an undervoltage trip time delay of 1.5 seconds. For the underfrequency event (Case 2), a frequency decay rate of 5 Hz/sec was assumed to begin at t = 0 seconds, decreasing pump speed, and thus, flow to all loops. At t = 1.0 seconds, the underfrequency trip setpoint of 55.0 Hz was reached. Rod motion occurred at t=1.6 seconds, following a 0.6-second underfrequency trip time delay.

The transients were analyzed using two computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE computer code (Reference 8) was then used to calculate the hot-channel-heat-flux-transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR transient was based on the minimum of the typical and thimble cells.

6.3.13.4 Acceptance Criteria

A complete-loss-of-forced-reactor-coolant-flow incident is classified by the ANS as a Condition III event. However, since a Condition II LOOP event could lead to a Condition III complete-loss-of-flow-event, the incident is analyzed to meet the more restrictive Condition II criteria to bound the complete loss-of-flow following a LOOP event.

The immediate effect from a complete-loss-of-forced-reactor-coolant flow is a rapid increase in reactor coolant temperature and subsequent increase in RCS pressure. The primary acceptance criterion for this event is that the critical heat flux should not be exceeded. This was ensured by demonstrating that the minimum DNBR did not go below the applicable safety analysis limit at any time during the transient.

The analysis results also demonstrated that pressure in the RCS and MSS remained below 110 percent of the respective design pressures to ensure that the applicable Condition II pressure criteria were met.

6.3.13.5 Results

For the IP3 SPU, both the undervoltage and frequency decay transients were analyzed. The VIPRE analyses for these scenarios confirmed that the minimum DNBR values were greater than the safety analysis limit, as demonstrated in Table 6.3-18.

The analysis of the complete-loss-of-flow event also demonstrated that the peak RCS and MSS pressures were well below their respective limits.

The sequence of events for the more limiting complete-loss-of-flow case, the frequency decay transient, is presented in Table 6.3-12. The transient results for this case are presented in Figures 6.3-70 through 6.3-72.

6.3.13.6 Conclusions

The analysis of the undervoltage and frequency decay cases, performed at SPU conditions, demonstrated that the DNBR did not decrease below the safety analysis limit at any time during the transients, thus, the integrity of the fuel was maintained. The peak primary and secondary system pressures remained below their respective limits at all times. Therefore, all applicable acceptance criteria were met.

6.3.14 Locked Rotor Accident

6.3.14.1 Introduction

The event postulated is an instantaneous seizure of a RCP rotor or the sudden break of a RCP shaft. Flow through the affected RCL is rapidly reduced, leading to initiation of a reactor trip on a low-RCL 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 primary flow results in a decreased tube-side film coefficient, and secondly 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 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 RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORVs, and opens the PSVs, in that sequence. The two PORVs 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 pressurizer spray, was not included in the analysis.

The consequences of a locked rotor (that is, an instantaneous seizure of a pump shaft) are very similar to those of a pump shaft break. The initial rate of 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 scenario. The analysis considered the most-limiting combination of conditions for the locked rotor and pump-shaft break events.

6.3.14.2 Input Parameters and Assumptions

Two cases are evaluated in the analysis. Both assumed one locked RCP rotor/shaft break with a total of four loops in operation.

The first case is analyzed to evaluate the RCS pressure and fuel clad temperature transient conditions. This case is analyzed using the STDP. Initial core power, reactor coolant temperature, and pressure are assumed to be at their maximum values consistent with the uprated full-power conditions including allowances for calibration and instrument errors. This assumption results in a conservative calculation of fuel clad temperature transient conditions and of the coolant insurge into the pressurizer, which in turn results in a maximum calculated peak RCS pressure. In addition, a 0.85-percent core flow penalty is modeled to account for RCS loop-to-loop flow asymmetry.

The second case is an evaluation of DNB in the core during the transient. This case is analyzed using the RTDP (Reference 3). Initial core power (consistent with SPU conditions) and reactor coolant pressure are assumed to be at their nominal values for steady state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the high T_{avg} program. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 3). A conservatively large absolute value of the Doppler-only power coefficient is used along with the most-positive MTC limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached. In addition, a 0.85-percent core flow penalty is modeled to account for RCS loop-to-loop flow asymmetry.

A conservatively low trip reactivity value (4.0-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position is modeled in addition to a conservative rod drop time (2.7 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the RSAC verification process.

Normal reactor control systems and engineered safety systems (for example, SI) 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.

6.3.14.3 Description of Analysis

The transients were analyzed using two computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE computer code (Reference 8) was then used to calculate the hot channel heat flux transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR transient is based on the minimum DNBR of the typical and thimble cells.

For the peak RCS pressure evaluation, the initial pressure was conservatively estimated as 60 psi above the nominal pressure of 2250 psia to allow for errors in pressurizer pressure measurement and control channels. This provides the highest possible rise in the coolant pressure during the transient. The pressure response reported in Table 6.3-13 was for the point in the RCS having the maximum pressure.

For a conservative analysis of fuel rod behavior, the hot spot evaluation assumed that DNB occurred at 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

After pump seizure, coolant flow in the loop with the faulted RCP decreased rapidly and RCS temperature and pressure increased. A reactor trip signal was generated when the flow in the affected loop reached 87 percent of nominal flow. Rod motion began 1 second later and the neutron flux was rapidly reduced by control rod insertion. As RCS pressure increased, no credit was taken for the pressure-reducing effect of pressurizer PORVs or pressurizer spray, nor was credit taken for 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 was provided by not including their effect.

Evaluation of DNB in the Core during the Event

For this event, DNB was assumed to occur in the core; therefore, an evaluation of the consequences with respect to fuel rod thermal transients was 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 2.50. The number of rods-in-DNB is conservatively calculated for use in dose consequence evaluations.

6.3.14.4 Acceptance Criteria

The RCP locked rotor accident is classified by the ANS as a Condition IV event. 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 RCS should be maintained below that which would cause stresses to exceed the faulted condition stress limits.

- Rods-in-DNB should be less than or equal to that assumed in the radiological dose analyses for the locked rotor/shaft break event.

6.3.14.5 Results

The results of the locked rotor/shaft break analysis are summarized in Table 6.3-13 and demonstrate that the acceptance criteria documented in subsection 6.3.14.4 continue to be met for the SPU. The number of rods-in-DNB (calculated as 0-percent rods-in-DNB) was less than that supported by the radiological dose analysis. Hence, the rods-in-DNB criterion was also met for the locked rotor/shaft break event. The calculated sequence of events is presented in Table 6.3-14 for the locked rotor event. The transient results for the peak-pressure/hot-spot case are provided in Figures 6.3-73 through 6.3-75.

6.3.14.6 Conclusions

The analysis performed at SPU conditions demonstrated that, for the locked rotor/shaft break event, the peak clad temperature calculated for the hot spot during the worst transient remained considerably less than 2700°F and the amount of zirconium-water reaction was small. Under such conditions, the core will remain in place and intact with no loss-of-core-cooling capability.

The analysis also confirmed that the peak RCS pressure reached during the transient was less than that which would cause stresses to exceed the faulted condition stress limits. The rods-in-DNB design criterion was also met.

The protection features previously described in subsection 6.3.14.1 provided mitigation for a locked rotor/shaft break transient such that the above criteria were satisfied.

6.3.15 Rupture of a CRDM Housing – RCCA Ejection

6.3.15.1 Introduction

This accident is defined as a mechanical failure of a CRDM pressure housing resulting in the ejection of the RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature, and terminated by reactor trip actuated by high nuclear power signals.

A failure of a CRDM housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons.

- Each full-length mechanism housing is completely assembled and shop-tested at 4100 psig.

- The mechanism housings are individually hydrotested after they are attached to the head adapters in the reactor vessel head and checked during the hydrotest of the completed RCS.

- Stress levels in the mechanism are not affected by anticipated system transients at power or by thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress ranges specified in the ASME Code, Section III, for Class I components.

- The latch mechanism housing and rod travel housing are each a single length of forged type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered.

A significant margin of strength in the elastic range, together with the large energy absorption capability in the plastic range, gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and rod travel housing are threaded joints reinforced by canopy-type rod welds.

In general, the reactor is operated with the RCCAs inserted only far enough to control design neutron flux shape. Reactivity changes caused by core depletion are compensated for by boron changes. Furthermore, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur. The position of all RCCAs is continuously indicated in the control room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one control rod assembly deviates from its bank. There are low and low-low level insertion alarm circuits for each bank. The control rod position monitoring and alarm systems are described in WCAP-7588 (Reference 10).

6.3.15.2 Input Parameters and Assumptions

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The most important parameters are discussed below. Table 6.3-15 lists the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either 3-D static methods or a synthesis of 1-D and 2-D calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. The analysis assumes adverse xenon distributions to provide worst-case results.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties.

Delayed Neutron Fraction, β

The ejected rod accident is sensitive to β if the ejected rod worth is equal to or greater than β, as in the zero-power transients. To allow for future fuel cycle flexibility, conservative estimates of β of 0.50 percent at beginning of cycle and 0.40 percent at end of cycle are used in the analysis.

Reactivity Weighting Factor

The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single-channel analysis. Physics calculations have been performed for temperature changes with a flat temperature distribution and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which, when applied to single-channel feedbacks, account for the effective whole-core feedbacks for the appropriate flux shape.

In this analysis, a 1-D (axial) spatial kinetics method is employed; thus axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature, as a function of time, accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative when compared to 3-D analysis (Reference 10).

Moderator and Doppler Coefficient

The critical boron concentrations at the BOL and EOL are adjusted in the nuclear code to obtain moderator density coefficient curves that are conservative when compared to the actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a 1-D steady-state computer code with a Doppler weighting factor of 1.0. The Doppler weighting factor will increase under accident conditions, as discussed above.

Heat Transfer Data

The FACTRAN (Reference 5) code, used to determine the hot spot transient, contains standard curves of thermal conductivity versus fuel temperature. During a transient, the peak centerline fuel temperature is independent of gap conductance during the transient. The cladding temperature is, however, strongly dependent on gap conductance and is highest for high-gap conductance. For conservatism, a high-gap heat transfer coefficient of 10,000 Btu/hr-ft^2-°F has been used during transients. This value corresponds to a negligible gap resistance and a further increase would have essentially no effect on the rate of heat transfer.

Coolant Mass Flow Rates

When the core is operating at full power, all four coolant pumps will always be operating. For zero-power conditions, the system is conservatively assumed to be operating with two pumps. The principal effect of operating at reduced flow is to reduce the film-boiling heat transfer coefficient. This results in higher peak cladding temperatures, but does not affect peak centerline fuel temperature. Reduced flow also lowers the critical heat flux. However, since DNB is always assumed at the hot spot and the heat flux rises very rapidly during the transient, this produces only second-order changes in the cladding and centerline fuel temperatures. All zero-power analyses for both average core and the hot spot are conducted assuming two pumps in operation.

Trip Reactivity Insertion

The trip reactivity insertion is assumed to be 4 percent ΔK/K from HFP and 2 percent ΔK/K from HZP, including the effect of one stuck RCCA. These values are also reduced by the ejected rod. The shutdown reactivity is simulated by dropping a rod of the required worth into the core. The start of rod motion occurs 0.55 seconds after reaching the power-range high-neutron-flux trip setpoint. It is assumed that insertion to dashpot occurs 2.7 seconds after the rods begin to fall. The time delay to full insertion, combined with the 0.55 second trip delay, conservatively delays insertion of shutdown reactivity into the core.

The minimum design shutdown margin available for this plant at HZP may only occur at EOL in the equilibrium cycle. This value includes an allowance for the worst stuck rod, an adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations have shown that two stuck RCCAs (one of which is the worst ejected rod) reduce the shutdown margin by about an additional 1 percent ΔK/K. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

6.3.15.3 Description of Analysis

This section describes the models used in the analysis of the rod ejection accident. Only the initial few seconds of the power transient are discussed, since the long-term considerations are the same as for a LOCA.

The calculation of the RCCA ejection transient is performed in two stages, first an average core channel calculation and then a hot region (hot spot) calculation. The average core calculation uses spatial neutron-kinetics methods to determine average power generation versus time including the various total core feedback effects; that is, Doppler reactivity and moderator reactivity. Enthalpy and temperature transients at the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and by performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is conservatively assumed to exist throughout the transient. A detailed discussion of the method of analysis can be found in WCAP-7588, Revision 1-A (Reference 10).

Average Core Analysis

The spatial-kinetics computer code, TWINKLE (Reference 4) is used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in one, two, or three spatial dimensions (rectangular coordinates) for 6 delayed neutron groups and up to 8000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant-heat-transfer model for calculation of point-wise Doppler and moderator feedback effects. This analysis uses the code as a 1-D axial kinetics code since it allows a more-realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to use very conservative methods (described below) for calculating the ejected rod worth and hot channel factor.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal heat flux times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot conditions before and after ejection are coincident. This is very conservative since the peak nuclear power after ejection will occur in or adjacent to the assembly with the ejected rod, whereas prior to ejection the power in this region will be depressed.

The average core energy addition, calculated as described above, is multiplied by the appropriate hot channel factors. The hot spot analysis uses the detailed fuel and clad transient heat transfer computer code, FACTRAN (Reference 5). This computer code calculates the transient temperature distribution in a cross section of a metal-clad UO_2 fuel rod and the heat flux at the surface of the rod, using as input the nuclear power versus time and local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative pellet radial power distribution is assumed within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 11) to determine the film-boiling coefficient after DNB. The use of the Bishop-Sandberg-Tong correlation conservatively assumes zero bulk fluid quality. The DNB heat flux is not calculated; instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted to force the full-power, steady-state temperature distribution to agree with fuel heat transfer design codes.

Reactor Protection

The protection for this accident, as explicitly modeled in the analysis, is provided by the power-range high-neutron-flux trip (high and low settings). This protection function is part of the Reactor Trip System. No single failure of the Reactor Trip System will negate the protection function required for the rod ejection accident, or adversely affect the consequences of the accident.

6.3.15.4 Acceptance Criteria

Due to the extremely low probability of an RCCA ejection accident, this event is classified as an ANS Condition IV event. As such, some fuel damage could be considered an acceptable consequence.

The Idaho Nuclear Corporation (Reference 12) has carried out comprehensive studies of the threshold of fuel failure and the threshold of significant conversion of the fuel thermal energy to mechanical energy as part of the SPERT project. Extensive tests of UO_2 zirconium-clad fuel rods representative of those present in PWR-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design exhibited failure as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 13) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreased 10 percent with fuel burnup. The clad failure mechanism appears to be melting for unirradiated (zero burnup) rods and brittle fracture for irradiated rods. The conversion ratio of thermal to mechanical energy is also important. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods, and 200 cal/gm for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/gm.

The real physical limits of this accident are that the rod ejection event and any consequential damage to either the core or the RCS must not prevent long-term core cooling and any offsite dose consequences must be within the guidelines of 10CFR100. More specific and restrictive criteria are applied to ensure fuel dispersal in the coolant, gross lattice distortion or severe shock waves will not occur. In view of the above experimental results, and the conclusions of WCAP-7588, Revision 1-A (Reference 10) and Westinghouse letter NS-NRC-89-3466 (Reference 14), the limiting criteria are:

- Average fuel pellet enthalpy at the hot spot must be maintained below 200 cal/gm.

- Peak reactor coolant pressure must be less than that which could cause RCS stresses to exceed the faulted-condition stress limits.

- Fuel melting is limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of the criterion in the first bulleted paragraph.

6.3.15.5 Results

A summary of the parameters used in the rod ejection analyses, and the analysis results, are listed in Table 6.3-15. For both HFP cases, control bank D is assumed at its insertion limit. For both HZP cases, control bank D is assumed fully inserted with banks B and C at their insertion limits.

The nuclear power and hot spot fuel and clad temperature transients for all 4 cases, BOL HFP, BOL HZP, EOL HFP, and EOL HZP are shown in Figures 6.3-76 through 6.3-83. The sequence of events for all 4 cases are listed in Tables 6.3-16 and 6.3-17.

For all four cases, the peak hot spot average enthalpy is less than the acceptance criteria limit of 200 cal/gm (360 Btu/lb) (maximum). The peak fuel centerline temperature for the HFP cases exceeded the conservative assumed temperature for fuel melt (4900°F at BOL; 4800°F at EOL), but the predicted fuel melt is less than the acceptance criterion limit of 10-percent fuel pellet volume (maximum) at the hot spot. The peak fuel centerline temperature for the HZP cases remained below the conservative assumed temperature for fuel melt (4900°F at BOL; 4800°F at EOL) and resulted in no fuel pellet melt at the hot spot.

A detailed calculation of the pressure surge for an ejected rod worth of 1 dollar at BOL HFP, indicates that the peak pressure does not exceed that which would cause RPV stress to exceed the faulted condition stress limits (Reference 10). Since the severity of the RCCA ejection analysis presented in this section does not exceed the severity of the "worst-case" peak pressure analysis in Reference 10, the RCCA ejection accident will not result in an excessive pressure rise or further adverse effects to the RCS for this plant.

6.3.15.6 Conclusions

Despite the conservative assumptions, the analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the RCS. The analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10 percent of the fuel rods in the core.

6.3.16 References

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11. ASME 65-HT-31, *Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux*, A. A. Bishop, R. O. Sandberg, and L. S. Tong, August 1965.

12. *Annual Report - SPERT Project, October 1968 - September 1969*, IN-1370 Idaho Nuclear Corporation, T. G. Taxebius, ed., June 1970.

13. ANL-7225, P 177, *Studies in TREAT of Zircaloy 2-Clad, UO_2-Core Simulated Fuel Elements*, R. C. Liimatainen and F. J. Testa, November 1966.

14. Letter NS-NRC-89-3466, *Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents*, from W. J. Johnson of Westinghouse Electric Corporation to Mr. R. C. Jones of the NRC, October 23,1989.

Table 6.3-1

List of Non-LOCA Events

Licensing Report Section	Event	UFSAR Section	Non-LOCA Computer Code
6.3.2	Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition	14.1.1	TWINKLE FACTRAN VIPRE
6.3.3	Uncontrolled RCCA Withdrawal at Power	14.1.2	RETRAN
6.3.4	RCCA Drop/Misoperation	14.1.3 / 14.1.4	LOFTRAN ANC VIPRE
6.3.5	CVCS Malfunction	14.1.5	N/A
6.3.6	Loss-of-External-Electrical Load	14.1.8	RETRAN
6.3.7	LONF	14.1.9	RETRAN
6.3.8	LOAC to the Station Auxiliaries	14.1.12	RETRAN
6.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	14.1.10	RETRAN VIPRE
6.3.10	Excessive Load Increase Incident	14.1.11	N/A
6.3.11	Rupture of a Steam Pipe	14.2.5	RETRAN ANC VIPRE
6.3.12	Partial Loss-of-Reactor-Coolant Flow	14.1.6	RETRAN VIPRE
6.3.13	Complete Loss-of-Reactor-Coolant Flow	14.1.6	RETRAN
6.3.14	Locked Rotor Accident	14.1.6	RETRAN VIPRE
6.3.15	Rupture of a CRDM Housing – RCCA Ejection	14.2.6	TWINKLE FACTRAN

Note:
No evaluation was performed for UFSAR Section 14.1.7, "Startup of an Inactive Reactor Coolant Loop." Per the IP3 ITS, it is required that all 4 RCPs be operating for reactor power operation.

Table 6.3-2 Trip Setpoint and Maximum Time Delay for Non-LOCA Safety Analysis		
Reactor Trip Function	**Time Delay (seconds)**	**Maximum Trip Setpoint Assumed for Analysis**
Power Range Flux (high setting)	0.5	118%
Power Range Flux (low setting)	0.5	35%
OTΔT	2.0[1]	Variable (see Section 6.3.1)
OPΔT	2.0[1]	Variable (see Section 6.3.1)
High-Pressurizer Pressure	2.0	2470 psia
Low-Pressurizer Pressure	N/A[2]	1850 psia
Low Reactor Coolant Flow	1.0	87% of loop flow
Low-Low Steam Generator Water Level	2.0	0% NRS
Turbine Trip	4.0	N/A
Engineering Safety Feature Actuation System (ESFAS) Function		
High-High Steam Generator Water Level (feedwater isolation) (turbine trip)	 12.0 5.0	 85% NRS 85% NRS

Note:

1. *Additional delays include RTD response time and filter time constant setting. The total delay is 10.5 seconds.*
2. Reactor trip function not explicitly credited in non-LOCA safety analyses; however, a low-pressurizer pressure reactor trip safety analysis setpoint is assumed, as the OTΔT and OPΔT reactor trip functions are required to protect the core between the low- and high-pressurizer pressure reactor trips.

Table 6.3-3 Non-LOCA Key Accident Analysis Assumptions for IP3 SPU	
NSSS Power	3230 MWt (bounds 3182 MWt)
Reactor Power	3216 MWt (bounds 3168 MWt)
NSSS Thermal Design Flow (per loop)	88,600 gpm
Minimum Measured Flow (per loop)	91,175 gpm
Core Bypass Flow Fraction (non-statistical) (statistical)	7.5% 6.8%
Programmed Full-Power RCS Average Temperature	572.0°F maximum 549.0°F minimum
Steam Generator Design	Westinghouse Model 44F
Maximum SGTP Level	10% uniform
DNB Methodology (where applicable)	RTDP
Safety Analysis Limit DNBR (RTDP, WRB-1 correlation)	1.45 (typical & thimble cell)
Max $F_{\Delta H}$ (non-statistical) (statistical)	1.70 1.635
Max F_Q (Locked Rotor) (RCCA Ejection)	2.50 2.56
Rod Average Thermal Output	6.644 kW/ft
Initial Condition Uncertainties: Power RCS flow Temperature Pressure Steam generator water level Pressurizer water level	 ± 2% RTP ± 2.9% ± 7.5°F (bounds ±4.8°F, +2.7/-0.7°F bias) ± 60 psi (bounds ± 52 psi, -3 psi bias) ± 10% NRS (bounds + 5.0/-8.5% NRS) ± 8.5% span (bounds ± 3.5% span, +1.6% span bias)

Table 6.3-4

Sequence of Events-Uncontrolled Rod Withdrawal from Subcritical Event

Event	Time (sec)
Start of Accident	0.0
Power Range High Neutron Flux Low Setpoint Reached	9.7
Peak Nuclear Power Occurs	9.9
Rods Begin to Fall into Core	10.2
Peak Heat Flux Occurs	11.8
Minimum DNBR Occurs	11.8
Peak Fuel Cladding Inner Temperature Occurs	12.3
Peak Fuel Average Temperature Occurs	12.5
Peak Fuel Centerline Temperature Occurs	13.2

Table 6.3-5

Sequence of Events-Uncontrolled RCCA Bank Withdrawal at Power Analysis

Case	Event	Time(s)
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (66 pcm/sec)	Initiation of uncontrolled RCCA withdrawal	0.0
	Power range high neutron flux (high setpoint reached)	1.9
	Rods begin to fall	2.4
	Minimum DNBR occurs	3.4
100% Power Minimum Feedback, Slow RCCA Withdrawal (1 pcm/sec)	Initiation of uncontrolled RCCA withdrawal	0.0
	OTΔT setpoint reached	95.5
	Rods begin to fall	97.5
	Minimum DNBR occurs	98.0

Table 6.3-6

Sequence of Events – Loss-of-Load/Turbine-Trip Event

Case	Event	Time (sec)
Peak Pressure Case	Loss-of-electrical load/turbine trip	0.0
	High-pressurizer pressure reactor trip setpoint reached	7.9
	Rods begin to drop	9.9
	Peak RCS pressure occurs	10.1
	Peak MSS pressure occurs	19.1
Minimum DNBR Case	Loss of electrical load/turbine trip	0.0
	OTΔT reactor trip setpoint reached	14.7
	Rods begin to drop	16.7
	Minimum DNBR occurs	17.9
	Peak MSS pressure occurs	23.1

Table 6.3-7 Time Sequence of Events for Loss-of-Normal Feedwater Flow	
Event	**Time (seconds)**
Main Feedwater Flow Stops	20.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	52.5
Rods Begin to Drop	54.5
Automatic AFW Flow from 1 MDAFWP (total 343 gpm) Initiated (split evenly between two loops)	112.5
Operator Action to Establish AFW Flow (an additional 343 gpm) to Remaining Steam Generators	654.5
Peak Water Level in the Pressurizer Occurs	1195.0

Table 6.3-8 Time Sequence of Events for Loss-of-Non-Emergency AC Power	
Event	**Time (seconds)**
Main Feedwater Flow Stops	20.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	59.0
Rods Begin to Drop	61.0
RCPs Begin to Coast Down	63.0
Automatic AFW Flow from 1 MDAFWP (total 343 gpm) Initiated (split evenly between two loops)	119.0
Operator Action to Establish AFW Flow (an additional 343 gpm) to Remaining Steam Generators	661.0
Peak Water Level in the Pressurizer Occurs	785.0

Table 6.3-9

Feedwater System Malfunction at Power – Sequence of Events

Event	Time (seconds)
One Main Feedwater Control Valve Begins to Open	0
Feedwater Control Valve Reaches Full-Open Position	15
High-High Steam Generator Water Level Trip Setpoint is Reached	85.08
Turbine Trip Initiated from High-High Steam Generator Level	89.98
Minimum DNBR Occurs	91.85
Rod Motion Begins/Reactor Trip occurs	93.99
Feedwater Isolation Valves Begin to Close	96.98

Table 6.3-10

Time Sequence of Events for the Rupture of a Main Steamline

Event	Case with Offsite Power Time (sec)	Case without Offsite Power Time (sec)
Double-Ended Steamline Rupture in Loop 1 (1.4 ft^2)	0.00	0.00
High Steamline Flow Setpoint Reached (2/4 loops)	0.25	0.25
LOOP (RCPs begin coasting down)	--	3.00
High Steamline Flow Signal Generated (2/4 loops)	8.25	8.25
Low-Low T_{avg} Setpoint Reached in Loop 1	8.81	9.24
Low-Low T_{avg} Setpoint Reached in Loop 2	11.53	12.56
Low-Pressurizer Pressure SI Setpoint Reached	15.29	16.94
Low-Low T_{avg} Signal Generated in Loop 1	16.81	17.24
Safety Injection and FWI Actuation due to Low Pressurizer Pressure	17.29	18.94
Low-Low T_{avg} Signal Generated in Loop 2	19.53	20.56
SLI Actuation due to Coincidence of Low-low T_{avg} (2/4 loops) / High Steam Flow (2/4 loops) ESF	19.54	20.57
MSIV Closure Loops 1, 2, 3, and 4	26.44[(1)]	27.47[(1)]
MFIV Closure Loops 1, 2, 3, and 4	27.19[(1)]	28.84[(1)]
SI Flow Initiated	29.31	40.95
Peak Core Heat Flux Occurs	39.80	67.72

Note:

1. Plus an additional 0.1 second for valve closure time.

Table 6.3-11 Sequence of Events – Partial Loss-of-Forced Reactor-Coolant-Flow Event		
Case	**Event**	**Time (sec)**
Partial Loss-of-Forced-Reactor-Coolant Flow (4 loops initially operating, 1 loop coasting down)	Coastdown begins	0.0
	Low flow reactor trip	1.5
	Rods begin to drop	2.5
	Minimum DNBR occurs	3.4

Table 6.3-12 Sequence of Events – Complete Loss-of-Forced Reactor-Coolant-Flow Event		
Case	**Event**	**Time (sec)**
Complete Loss-of-Forced-Reactor-Coolant Flow (frequency decay)	Frequency decay begins	0.0
	Underfrequency trip setpoint reached	1.0
	Rods begin to drop	1.6
	Minimum DNBR occurs	3.7

Table 6.3-13 Summary of Results for the Locked Rotor/Shaft Break Transient		
Criteria	**Analysis Value**	**Limit**
Maximum Clad Temperature at Core Hot Spot, °F	1792	2700
Maximum Zr-H_2O Reaction at Core Hot Spot, wt. %	0.28	16
Maximum RCS Pressure, psia	2530	2750

Table 6.3-14 Sequence of Events – Locked Rotor/Shaft Break Transient	
Event	**Time (sec)**
Rotor on One Pump Locks/Shaft Breaks	0.0
Low-Flow Reactor Trip Setpoint Reached	0.1
Rods Begin to Drop	1.1
Maximum Clad Temperature Occurs	3.9
Maximum RCS Pressure Occurs	5.9

Table 6.3-15 Inputs and Results of the RCCA Ejection Accident Analysis				
	Beginning of Cycle HFP	**Beginning of Cycle HZP**	**End of Cycle HFP**	**End of Cycle HZP**
Power Level, %	102	0	102	0
Ejected Rod Worth, %ΔK	0.17	0.65	0.20	0.80
Delayed Neutron Fraction, %	0.50	0.50	0.40	0.40
Feedback Reactivity Weighting	1.46	2.16	1.50	2.95
Trip reactivity, %ΔK	4.0	2.0	4.0	2.0
F_q before Rod Ejection	2.56	--	2.56	--
Ejected rod F_q	6.8	12.0	7.1	20.0
Number of Operational Pumps	4	2	4	2
Max Fuel Pellet Average Temperature, °F	4117	2524	3989	3066
Max Fuel Centerline Temperature, °F	4974	2900	4876	3425
Max Clad Average Temperature, °F	2256	1892	2177	2320
Max Fuel Stored Energy, Btu/lb	325	182	313	229
Fuel Melt at the Hot Spot, %	7.78	0	7.52	0

Table 6.3-16

Sequence of Events – RCCA Ejection Accident

Case	Event	Time (sec)
BOL, Full Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.05
	Peak nuclear power occurs	0.13
	Rods begin to fall	0.60
	Peak fuel average temperature occurs	2.36
	PCT occurs	2.46
EOL, Full Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.04
	Peak nuclear power occurs	0.13
	Rods begin to fall	0.59
	Peak fuel average temperature occurs	2.48
	PCT occurs	2.56

Table 6.3-17 Sequence of Events – RCCA Ejection Accident		
Case	**Event**	**Time (sec)**
BOL, Zero Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.34
	Peak nuclear power occurs	0.40
	Rods begin to fall	0.89
	PCT occurs	2.52
	Peak fuel average temperature occurs	2.65
EOL, Zero Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.18
	Peak nuclear power occurs	0.21
	Rods begin to fall	0.73
	PCT occurs	1.56
	Peak fuel average temperature occurs	1.78

Table 6.3-18 Non-LOCA Analysis Limits and Results				
Licensing Report Section	**Event Description**	**Result Parameter**	**Analysis Result**	
			Analysis Limit	**Limiting Case**
6.3.2	Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition	Minimum DNBR below first mixing vane grid (non-RTDP, W-3 correlation) (thimble/typical)	1.45/1.45	1.72/1.93
		Minimum DNBR above first mixing vane grid (non-RTDP, WRB-1 correlation) (thimble/typical)	1.30/1.30	2.04/2.08
		Maximum fuel centerline temperature, °F	4800	2346
6.3.3	Uncontrolled RCCA Withdrawal at Power	Minimum DNBR (RTDP, WRB-1)	1.45	1.53
		Peak RCS pressure, psia	2750.0	2748.45
		Peak main steam system pressure, psia	1208.5	1179.24
6.3.4	RCCA Drop/Misoperation	Minimum DNBR (RTDP, WRB-1)	1.45	> 1.45
		Peak linear heat generation (kW/ft)	22.7	< 22.7
		Peak uniform cladding strain (%)	1.0	< 1.0
6.3.5	CVCS Malfunction	Minimum time to loss of shutdown margin, minutes		
	- Mode 1 with manual rod control		15	> 34 (Mode 1 with manual)
	- Mode 1 with automatic rod control		15	> 36 (Mode 1 with auto)
	- Mode 2		15	> 26 (Mode 2)
	- Mode 6		30	> 34 (Mode 6)

Table 6.3-18 (Cont.) Non-LOCA Analysis Limits and Results				
Licensing Report Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
6.3.6	Loss-of-External-Electrical Load	Minimum DNBR (RTDP, WRB-1)	1.45	1.85
		Peak RCS pressure, psia	2750.0	2700.50
		Peak main steam system pressure, psia	1208.5	1182.87
6.3.7	LONF	Maximum pressurizer mixture volume, ft3	1800.0	1596.1
6.3.8	LOAC to the Station Auxiliaries	Maximum pressurizer mixture volume, ft3	1800.0	1443.3
6.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	Minimum DNBR (RTDP, WRB-1)	1.45	2.21(HFP) (1)(HZP)
6.3.10	Excessive Load Increase Incident	Minimum DNBR (RTDP, WRB-1)	1.45	> 1.45
6.3.11	Rupture of a Steam Pipe	Minimum DNBR (non-RTDP, W-3)	1.45	2.37
6.3.12	Partial Loss-of-Reactor-Coolant Flow	Minimum DNBR (RTDP, WRB-1)	1.45	2.222
6.3.13	Complete Loss-of-Reactor-Coolant Flow			
	- Undervoltage	Minimum DNBR (RTDP, WRB-1)	1.45	1.956 (under-voltage)
	- Frequency Decay		1.45	1.865 (frequency decay)
6.3.14	Locked Rotor Accident	See Table 6.3-13		
6.3.15	Rupture of a CRDM Housing – RCCA Ejection	Maximum fuel pellet average enthalpy, Btu/lb	360	See Table 6.3-15
		Maximum fuel melt, %	10	See Table 6.3-15
		Peak RCS pressure, psia	Generically addressed in Section 6.3 Reference 10	

Note:

1. Bounded by zero power steam line break.

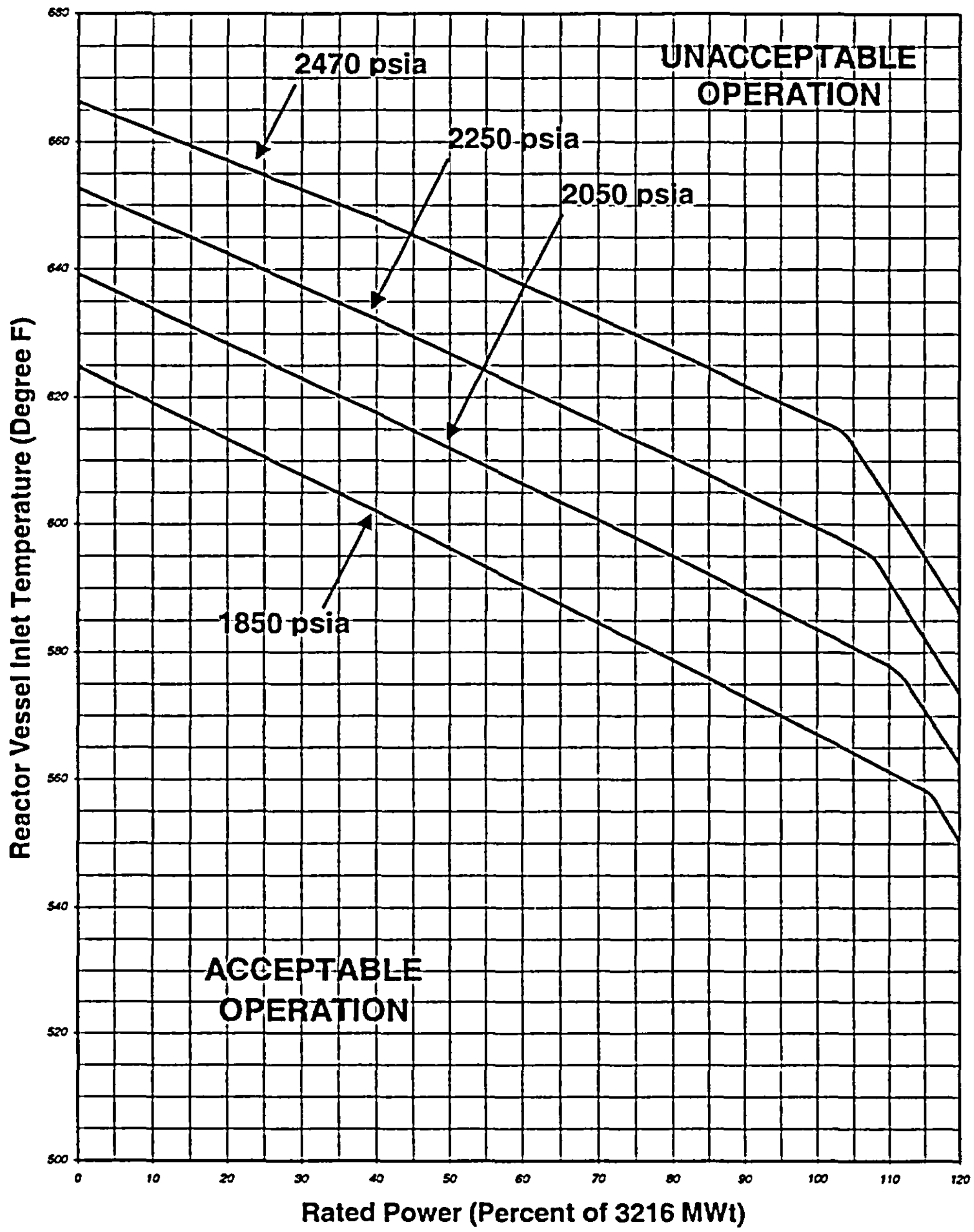


Figure 6.3-1

Reactor Core Safety Limit – Four Loops in Operation

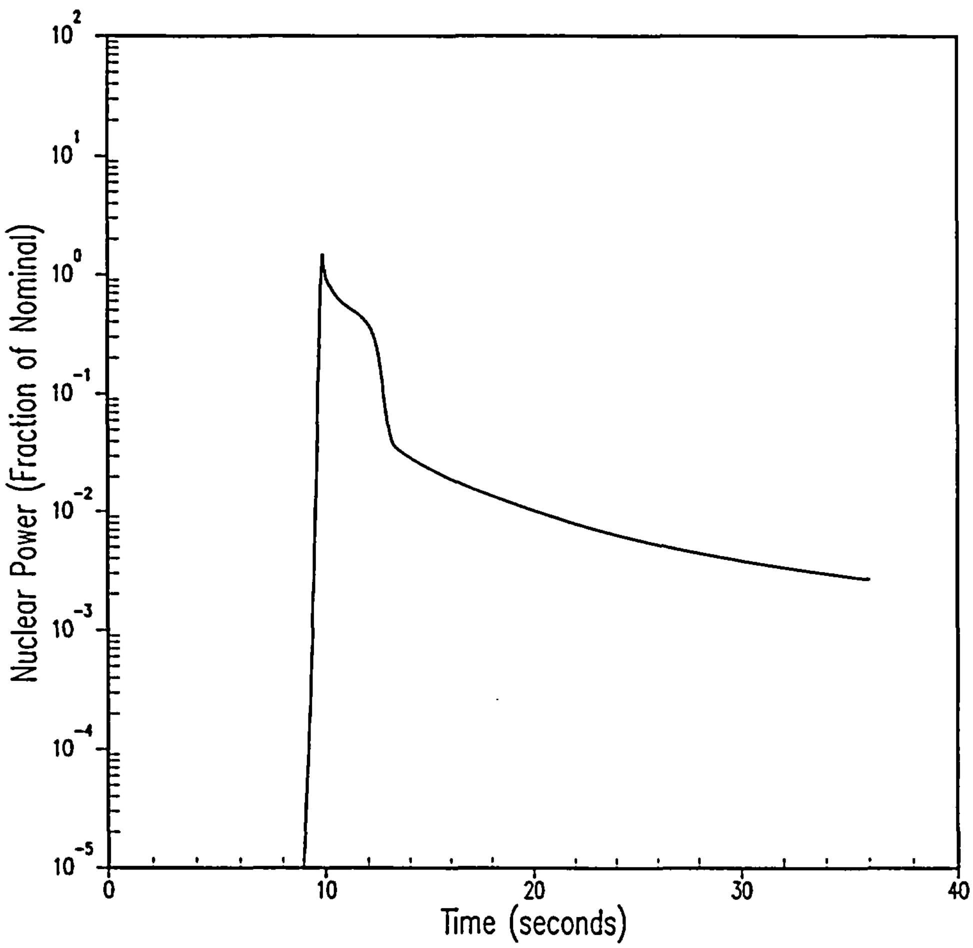


Figure 6.3-2

Nuclear Power Transient for Uncontrolled Rod Withdrawal from a Subcritical Condition

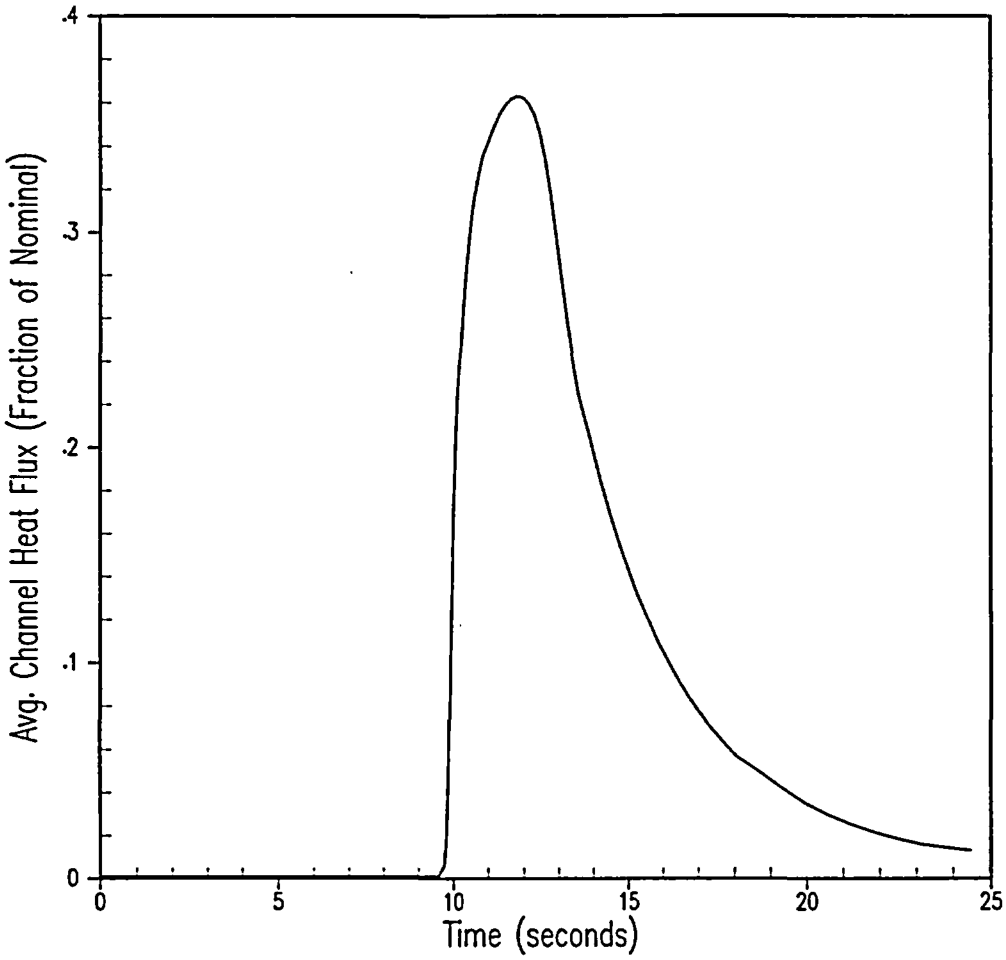


Figure 6.3-3

Thermal Flux Transient for Uncontrolled Rod Withdrawal from a Subcritical Condition

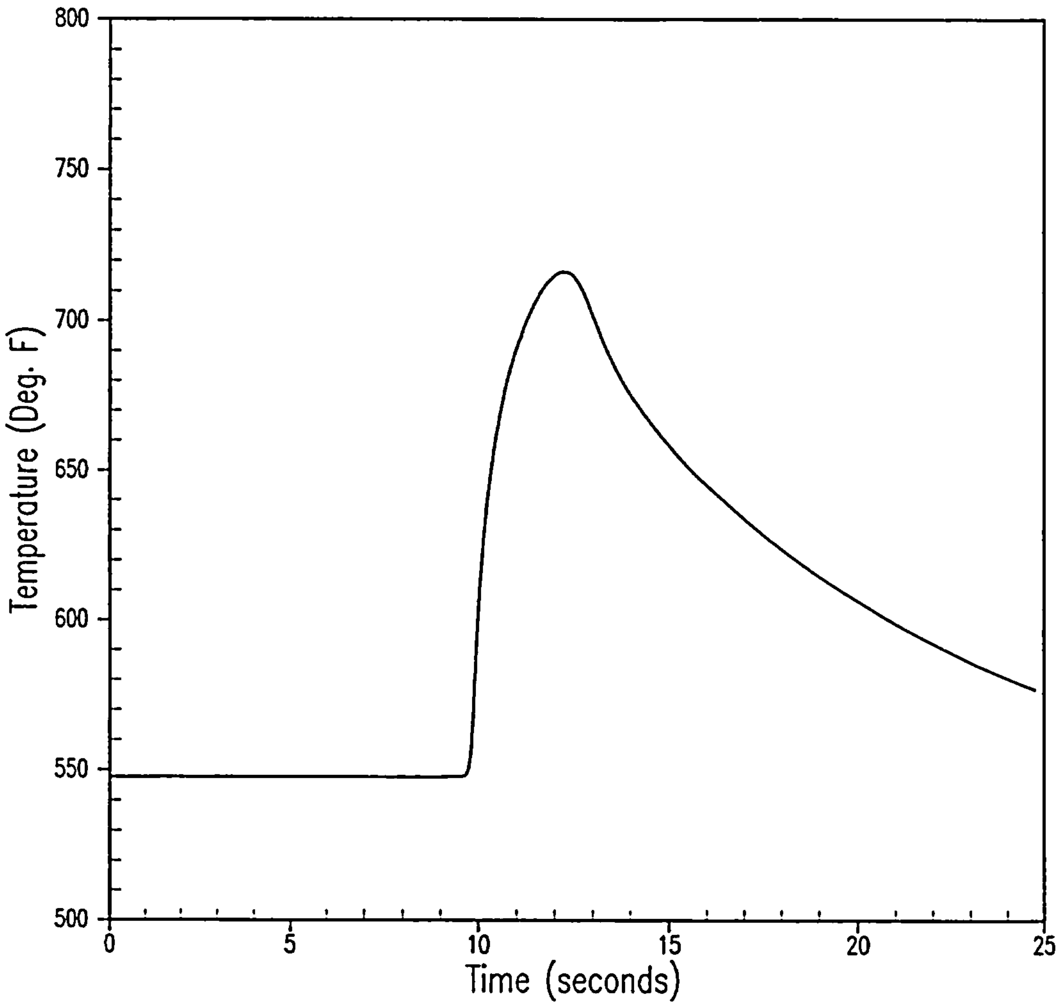


Figure 6.3-4

Hot Spot Clad Inner Temperature Transient for

Uncontrolled Rod Withdrawal from a Subcritical Condition

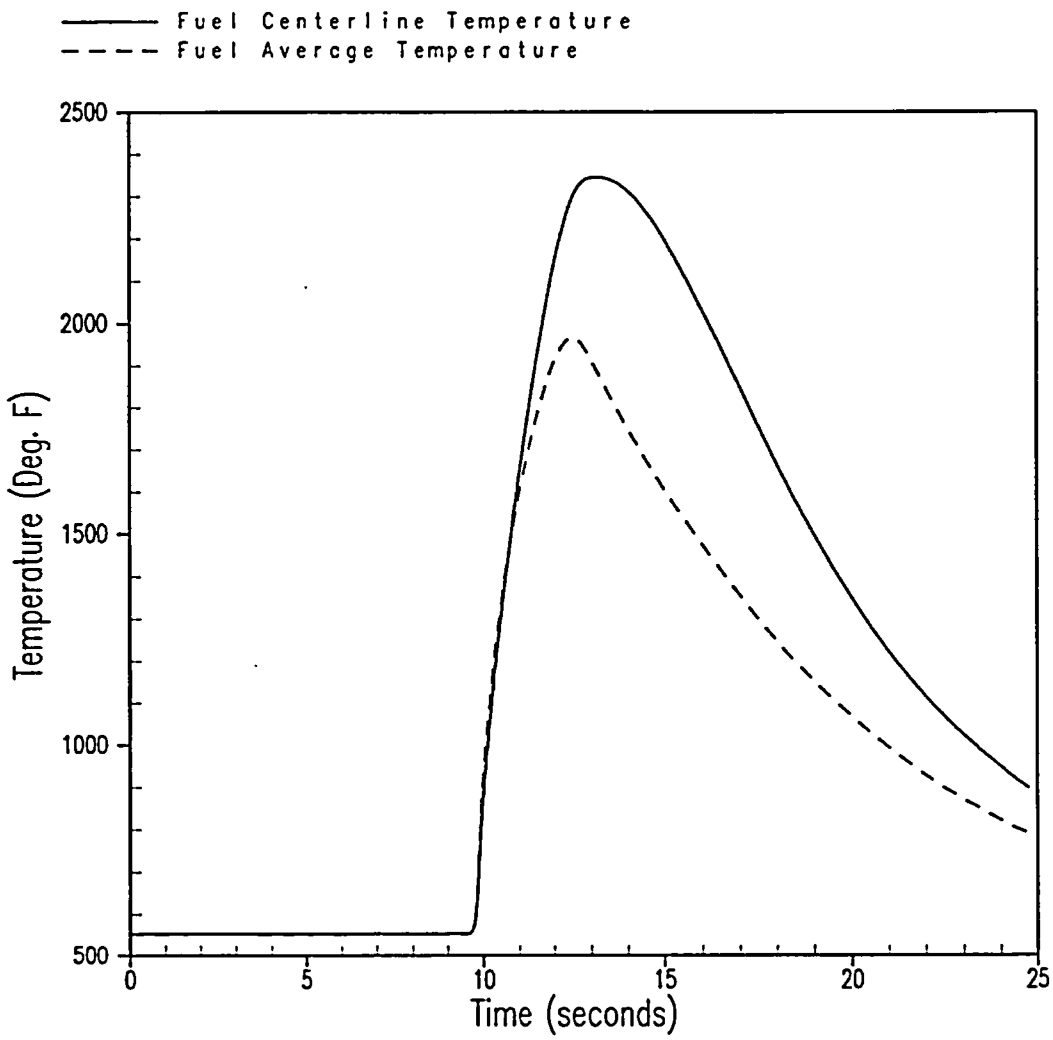


Figure 6.3-5

Hot Spot Fuel Centerline and Average Temperature Transients for Uncontrolled Rod Withdrawal from a Subcritical Condition

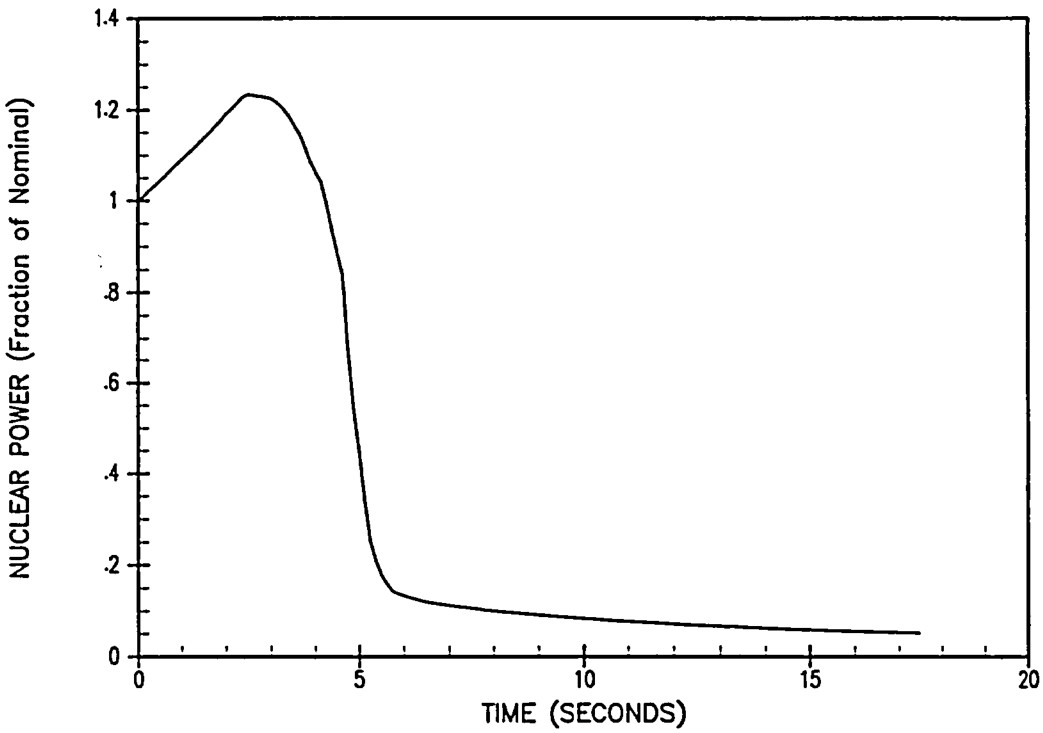


Figure 6.3-6

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Nuclear Power vs. Time)

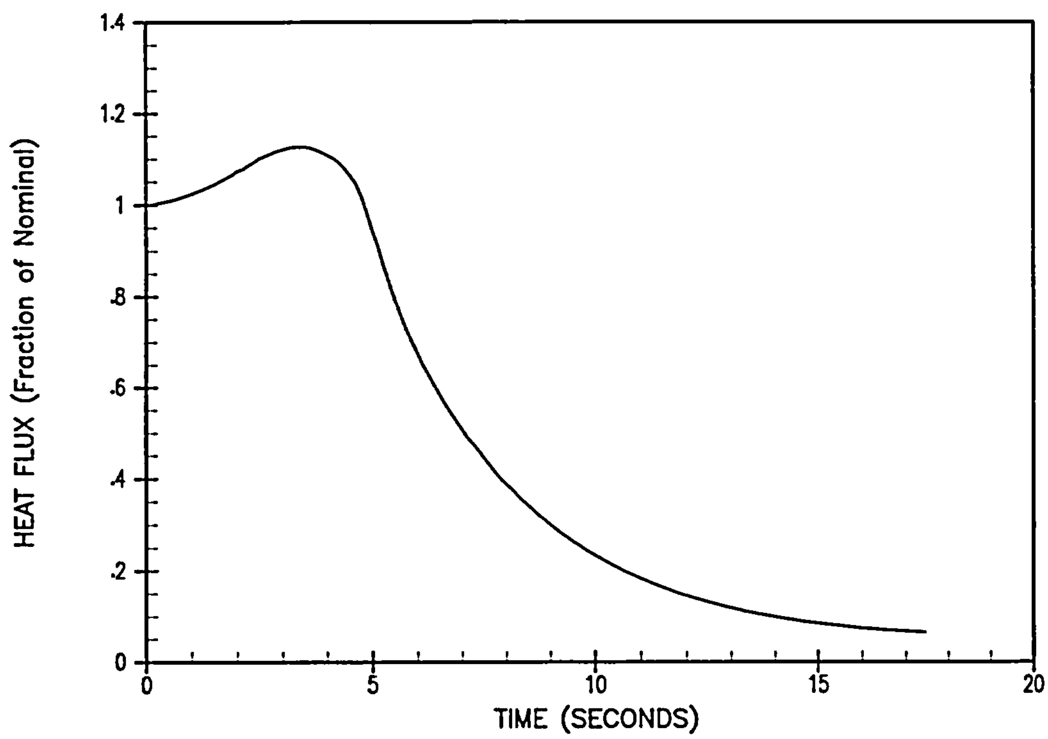


Figure 6.3-7

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Core Heat Flux vs. Time)

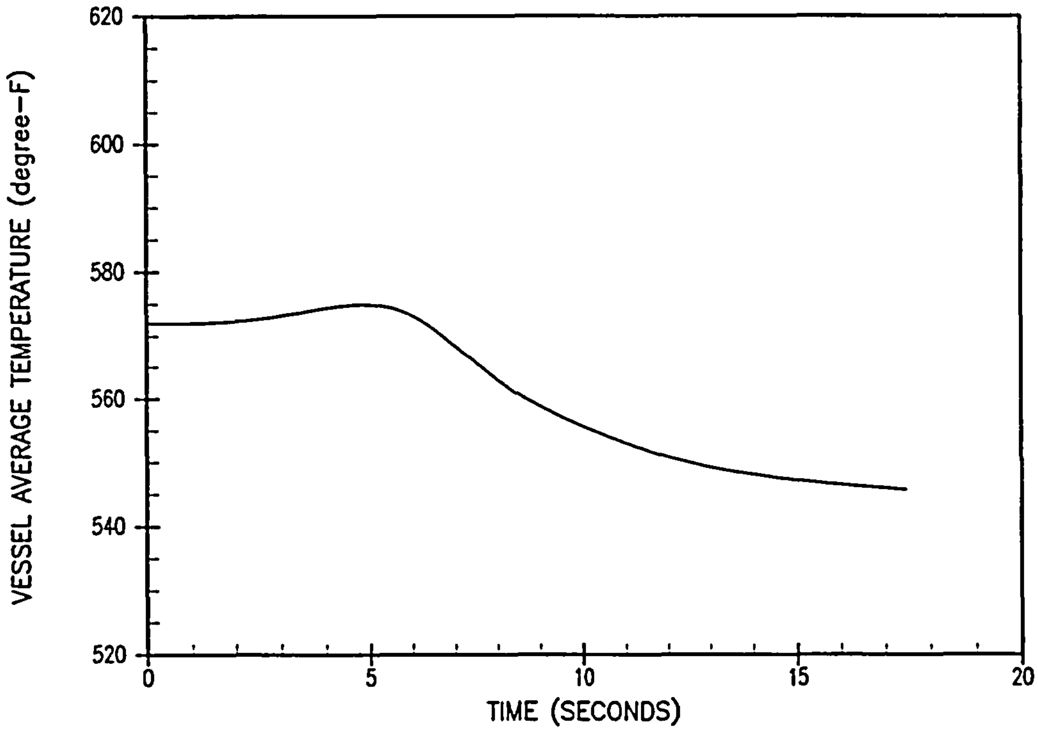


Figure 6.3-8

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Vessel Average Temperature vs. Time)

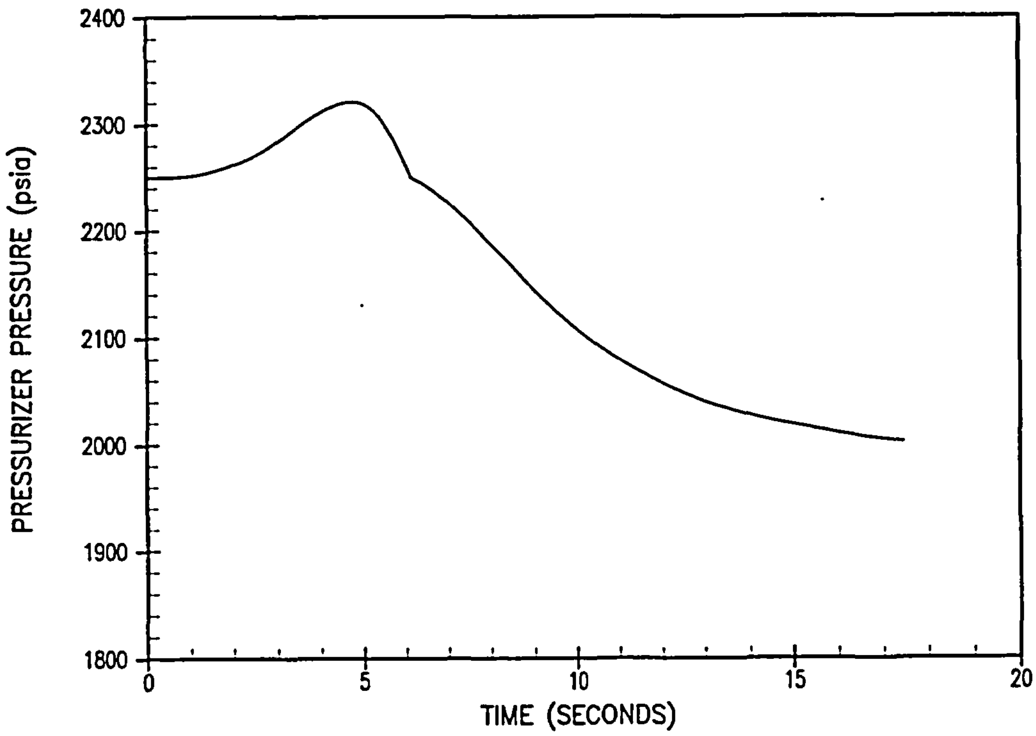


Figure 6.3-9

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Pressure vs. Time)

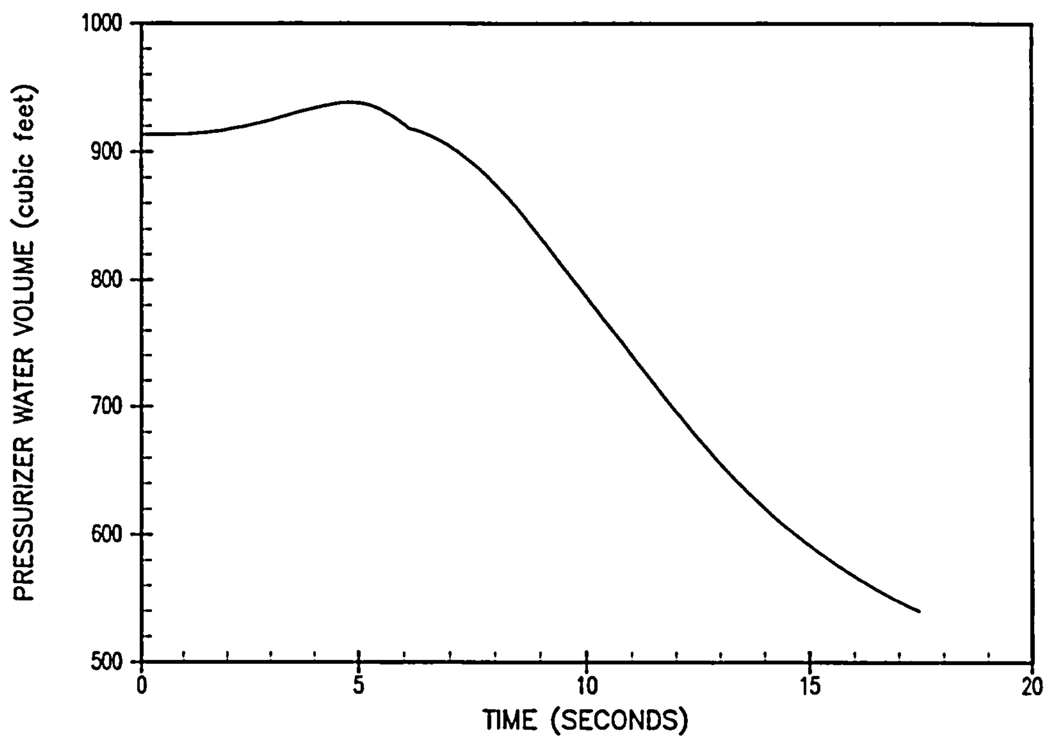


Figure 6.3-10

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Water Volume vs. Time)

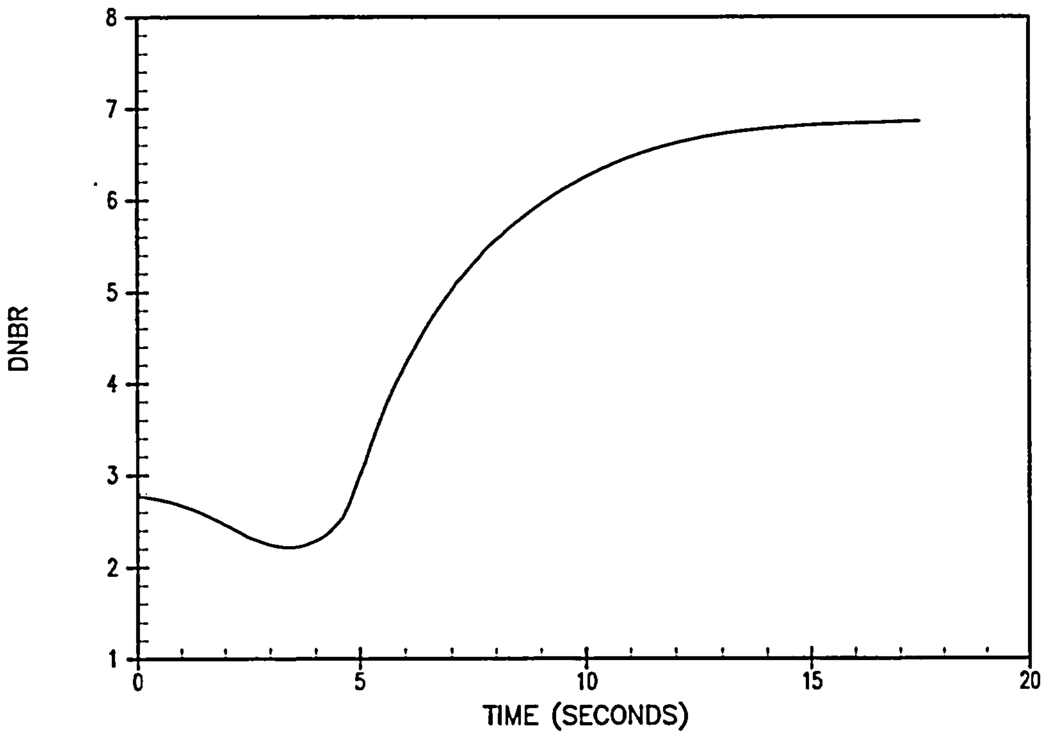


Figure 6.3-11

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (DNBR vs. Time)

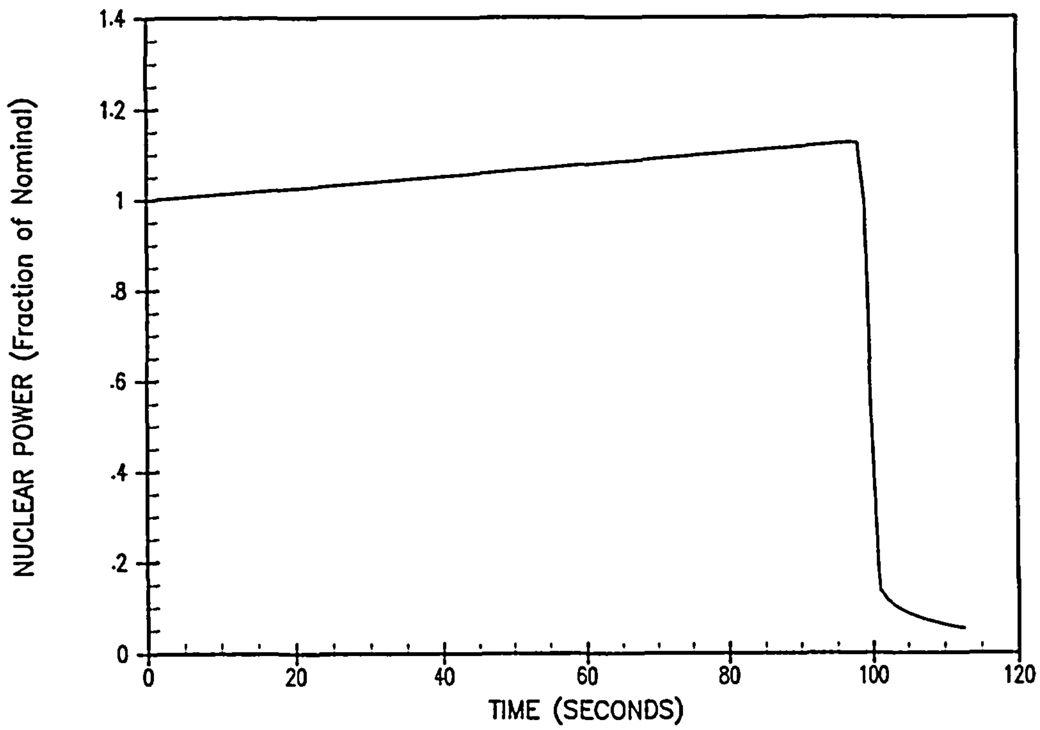


Figure 6.3-12

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Nuclear Power vs. Time)

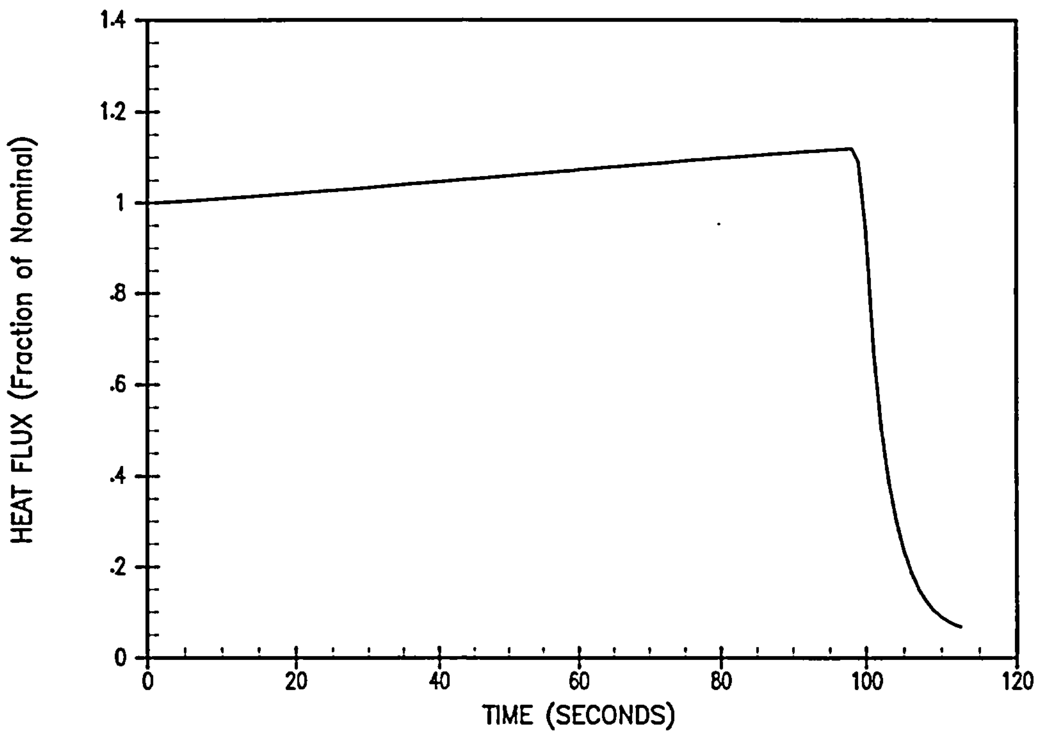


Figure 6.3-13

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Core Heat Flux vs. Time)

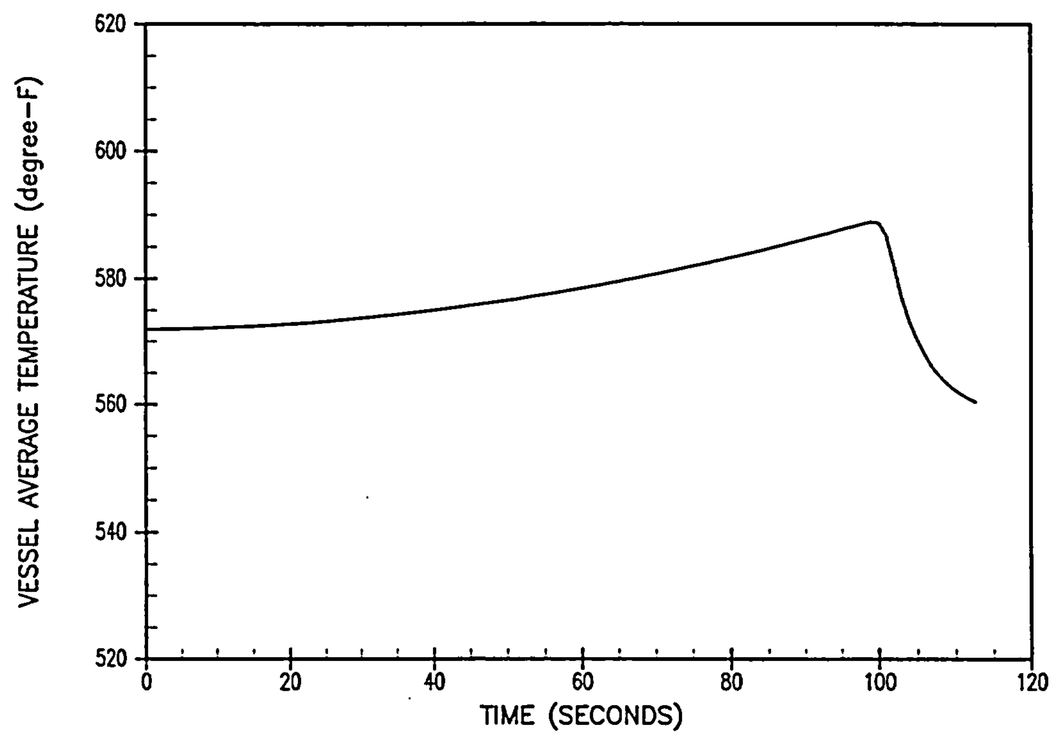


Figure 6.3-14

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second 100% Power - Minimum Reactivity Feedback (Vessel Average Temperature vs. Time)

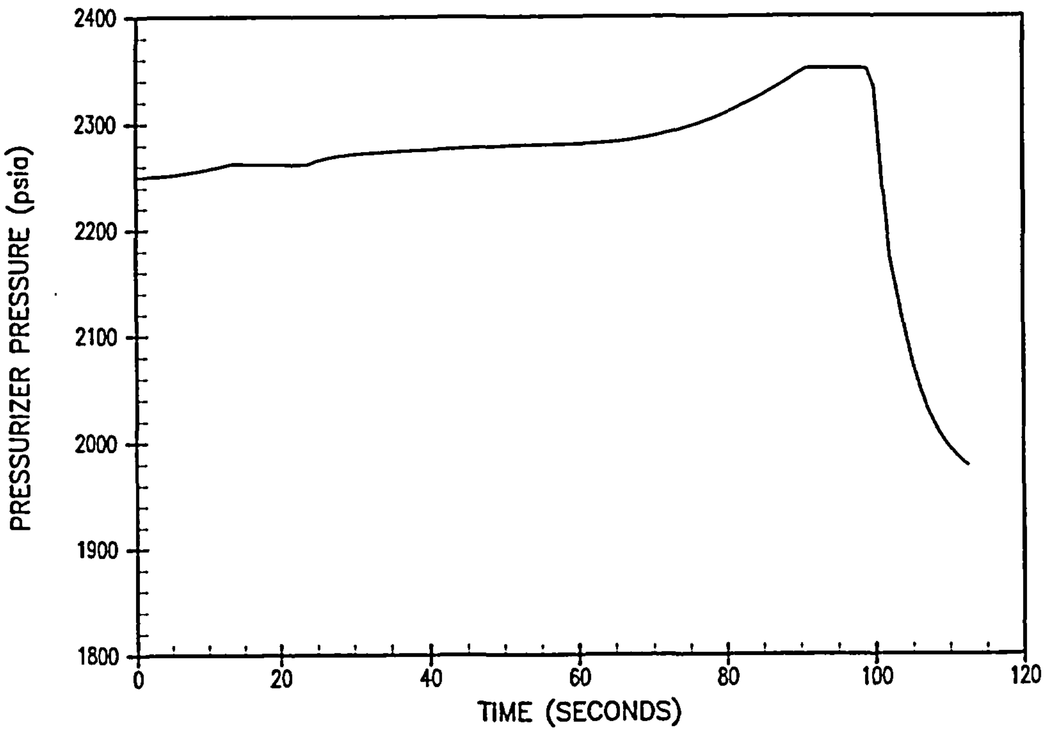


Figure 6.3-15

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Pressure vs. Time)

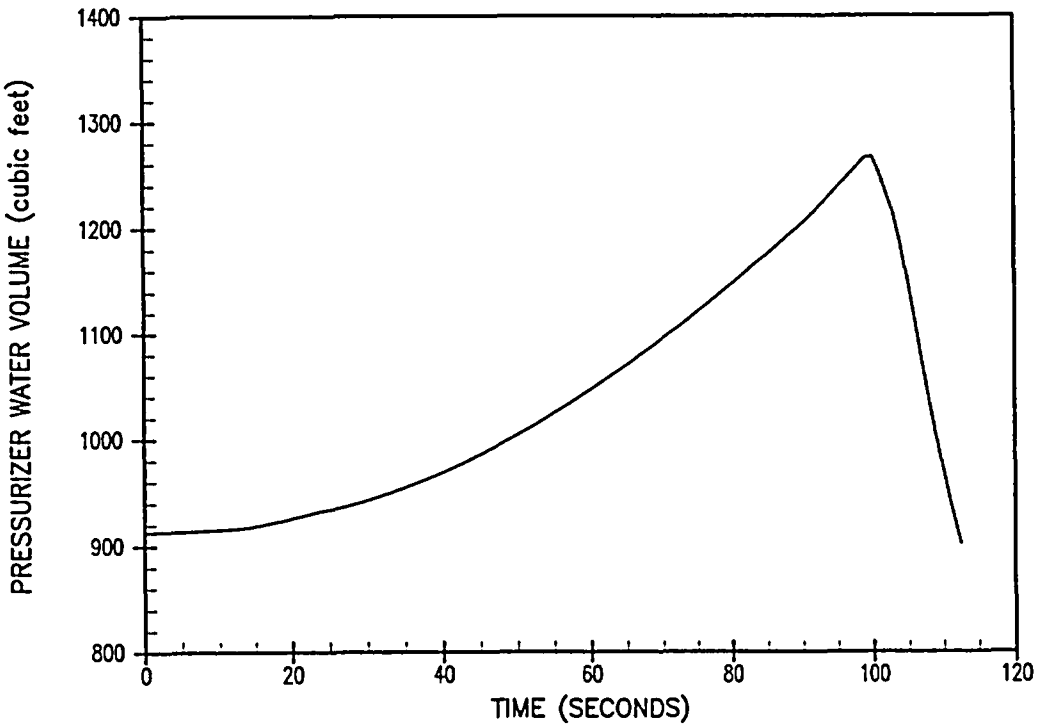


Figure 6.3-16

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Water Volume vs. Time)

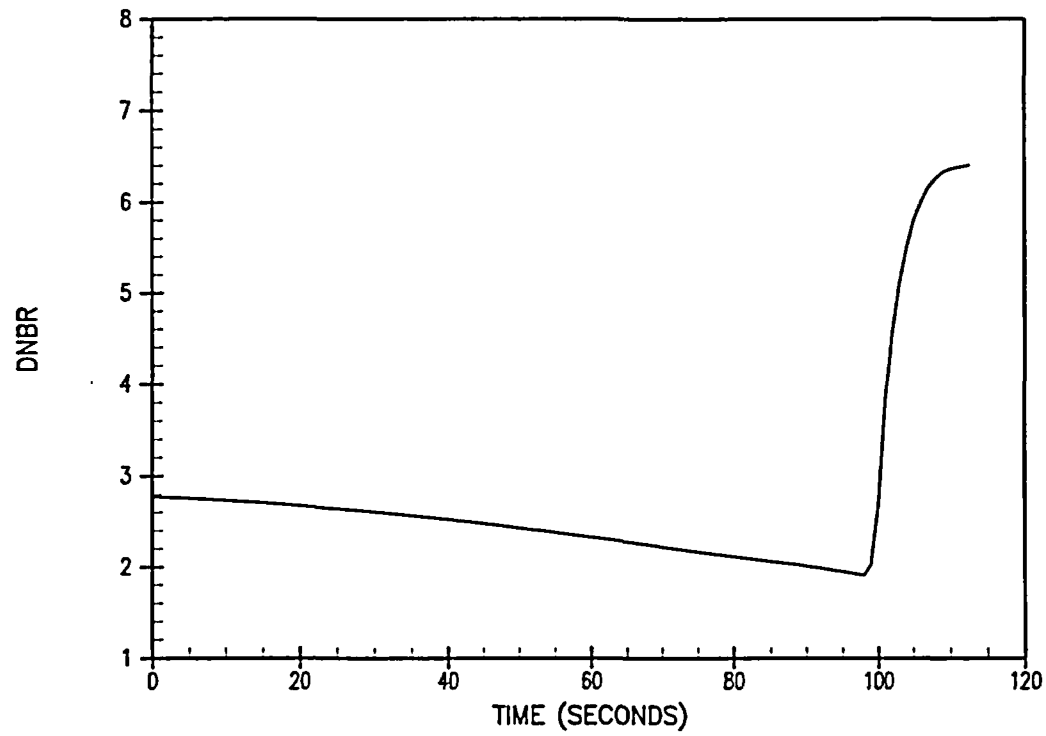


Figure 6.3-17

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (DNBR vs. Time)

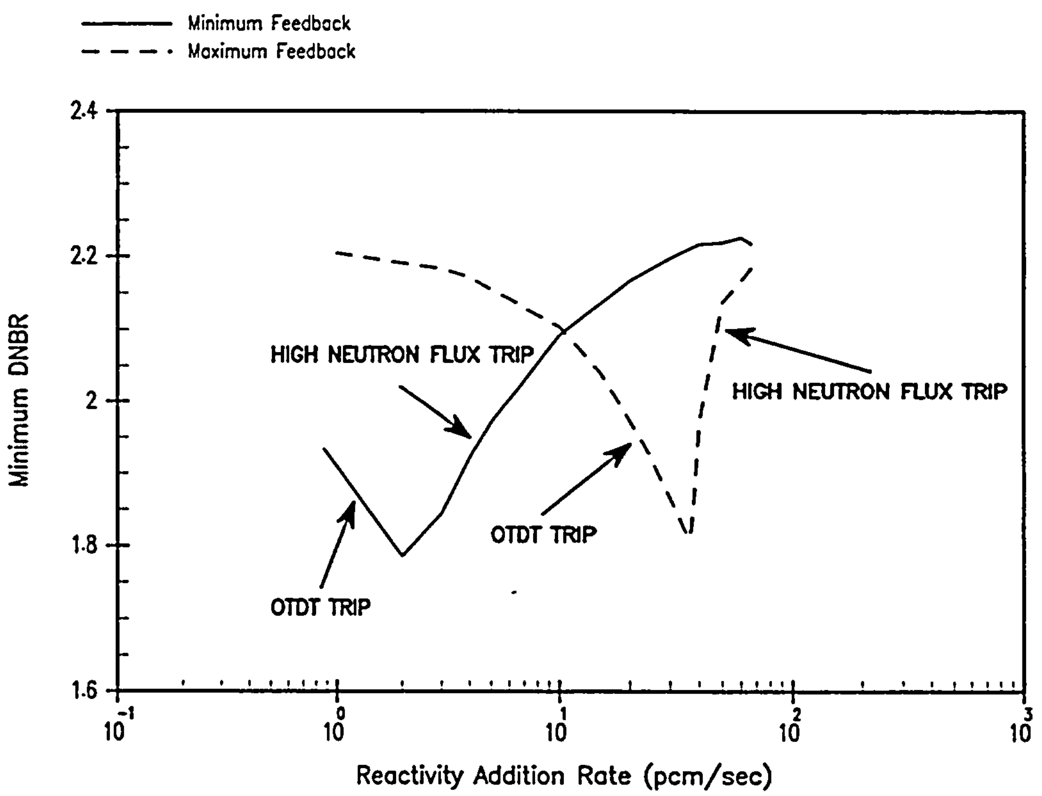


Figure 6.3-18

Uncontrolled RCCA Bank Withdrawal at 100% Power

Minimum DNBR versus Reactivity Insertion Rate

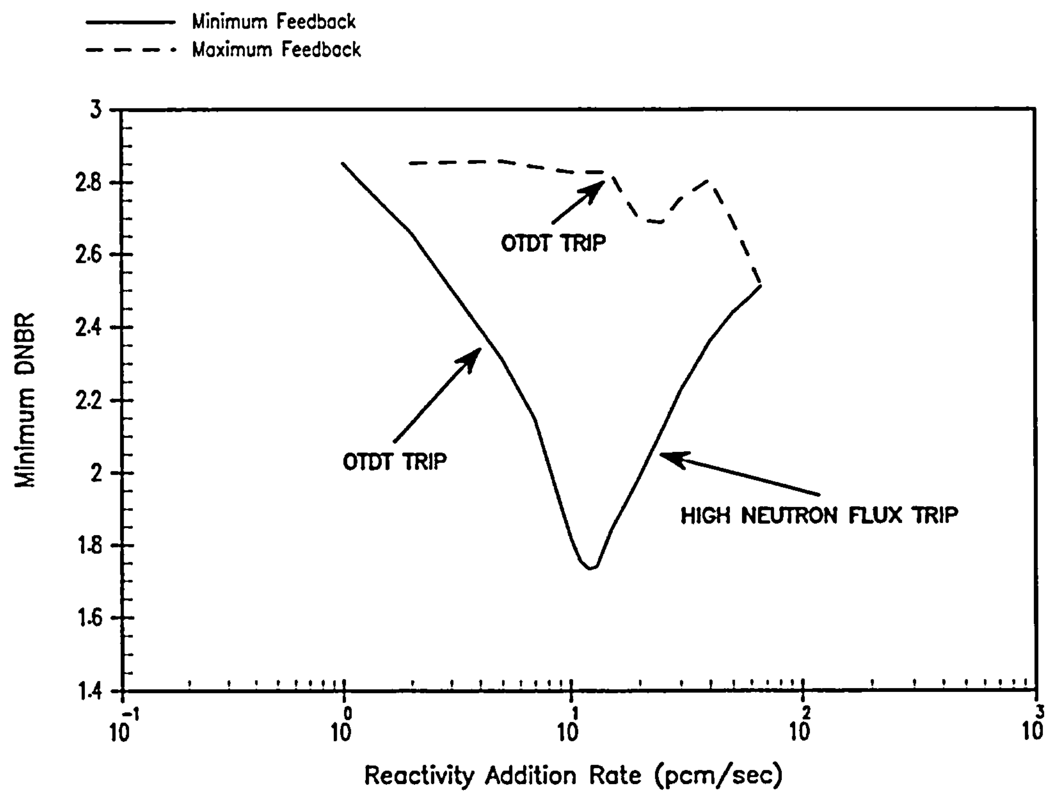


Figure 6.3.3-19

Uncontrolled RCCA Bank Withdrawal at 60% Power

Minimum DNBR vs. Reactivity Insertion Rate

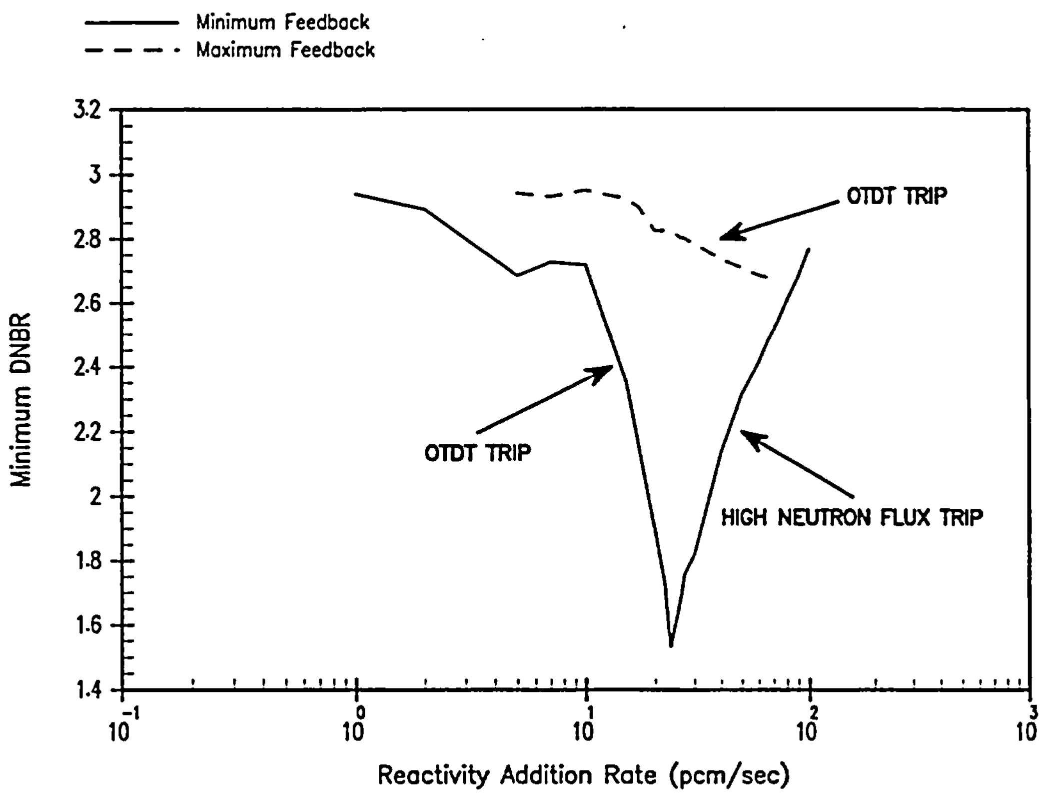


Figure 6.3-20

Uncontrolled RCCA Bank Withdrawal at 10% Power

Minimum DNBR vs. Reactivity Insertion Rate

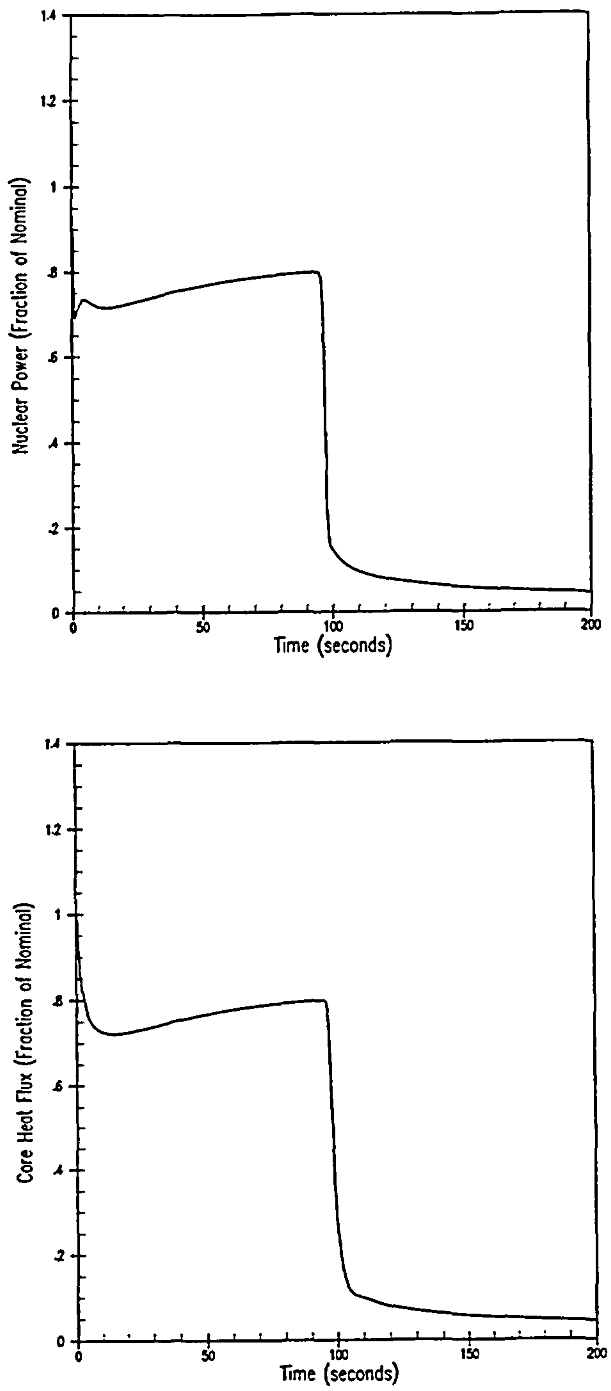


Figure 6.3-21

Dropped Rod Transient with Manual Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 400 pcm at BOL (small negative MTC)

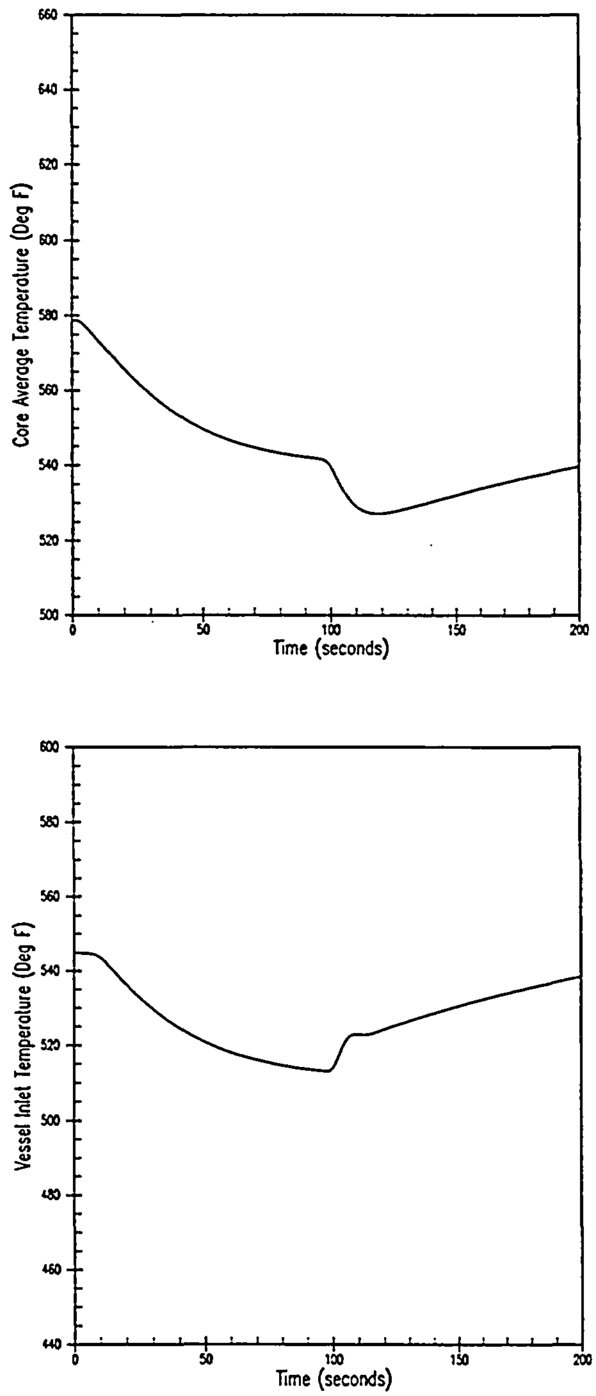


Figure 6.3-22

Dropped Rod Transient with Manual Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 400 pcm at BOL (small negative MTC)

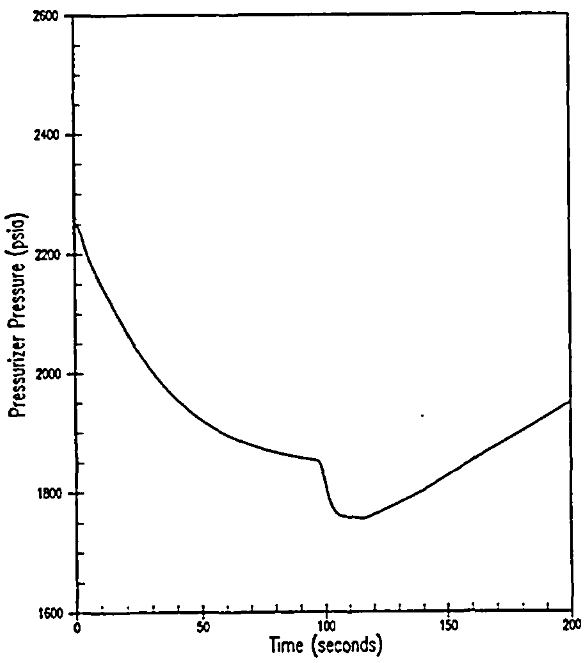


Figure 6.3-23

Dropped Rod Transient with Manual Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 400 pcm at BOL (small negative MTC)

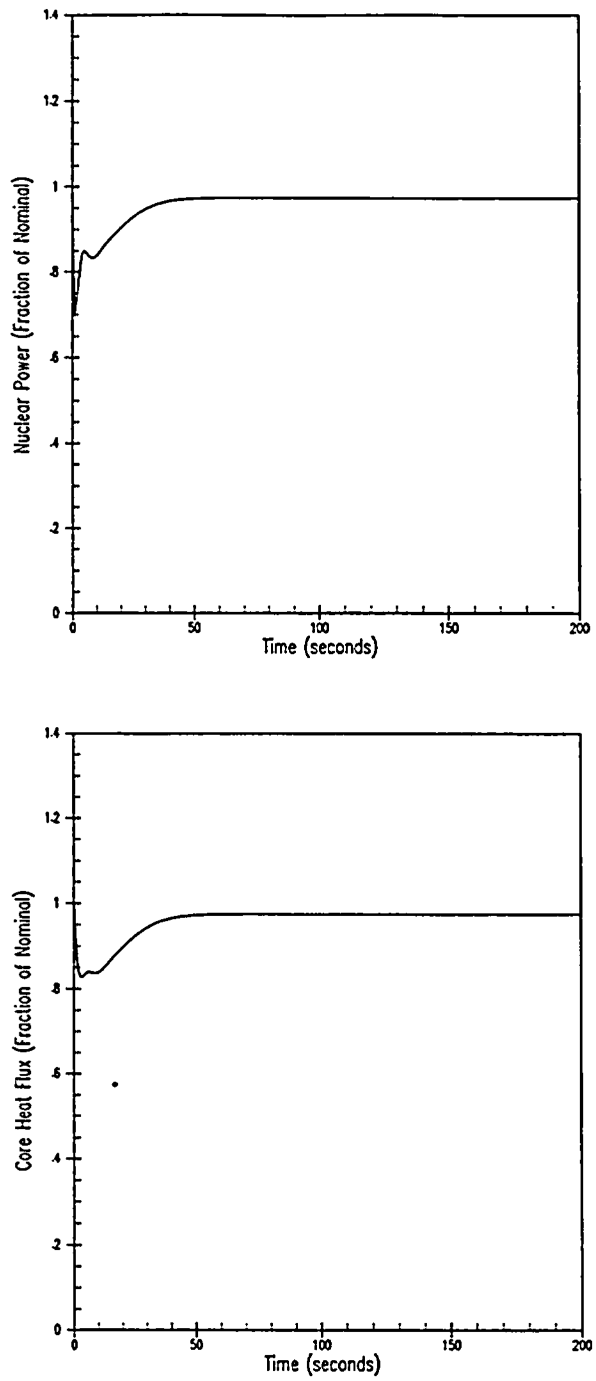
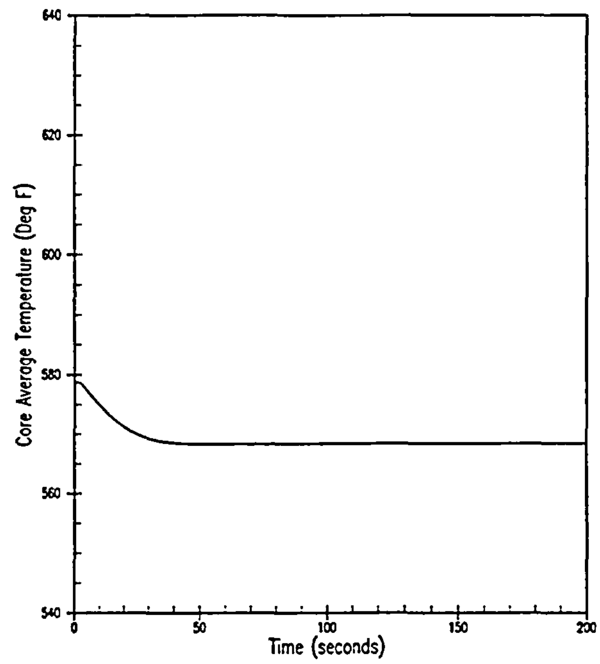


Figure 6.3-24

Dropped Rod Transient with Manual Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 400 pcm at EOL (large negative MTC)



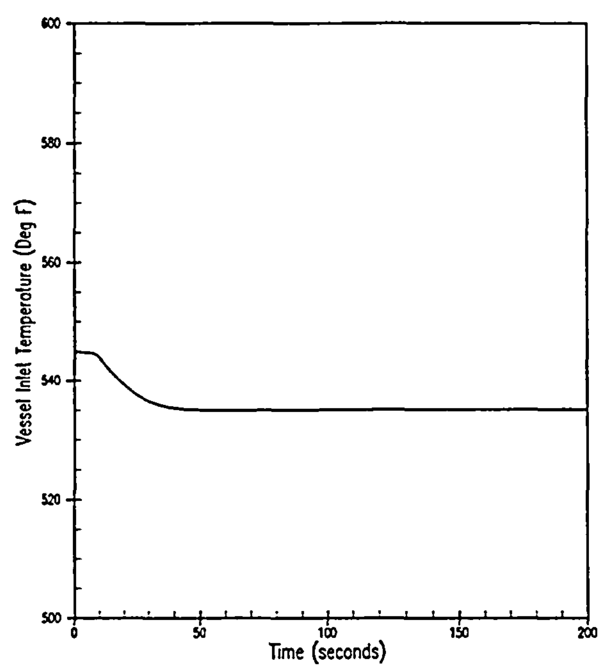


Figure 6.3-25

Dropped Rod Transient with Manual Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 400 pcm at EOL (large negative MTC)

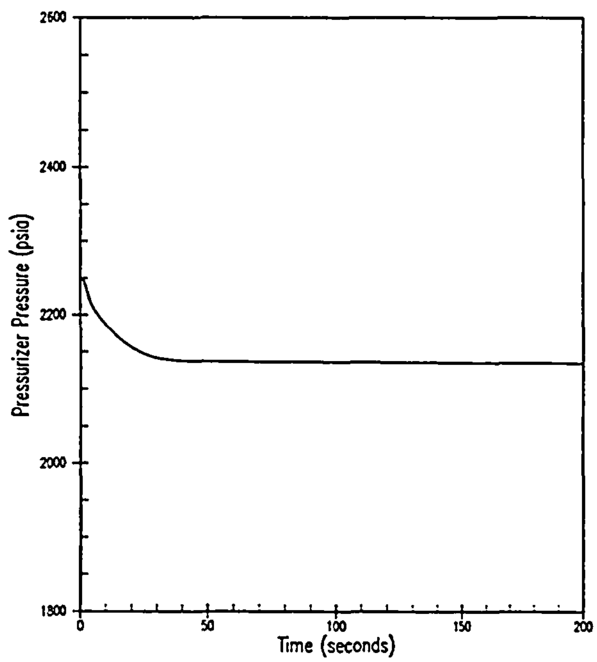


Figure 6.3-26

Dropped Rod Transient with Manual Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 400 pcm at EOL (large negative MTC)

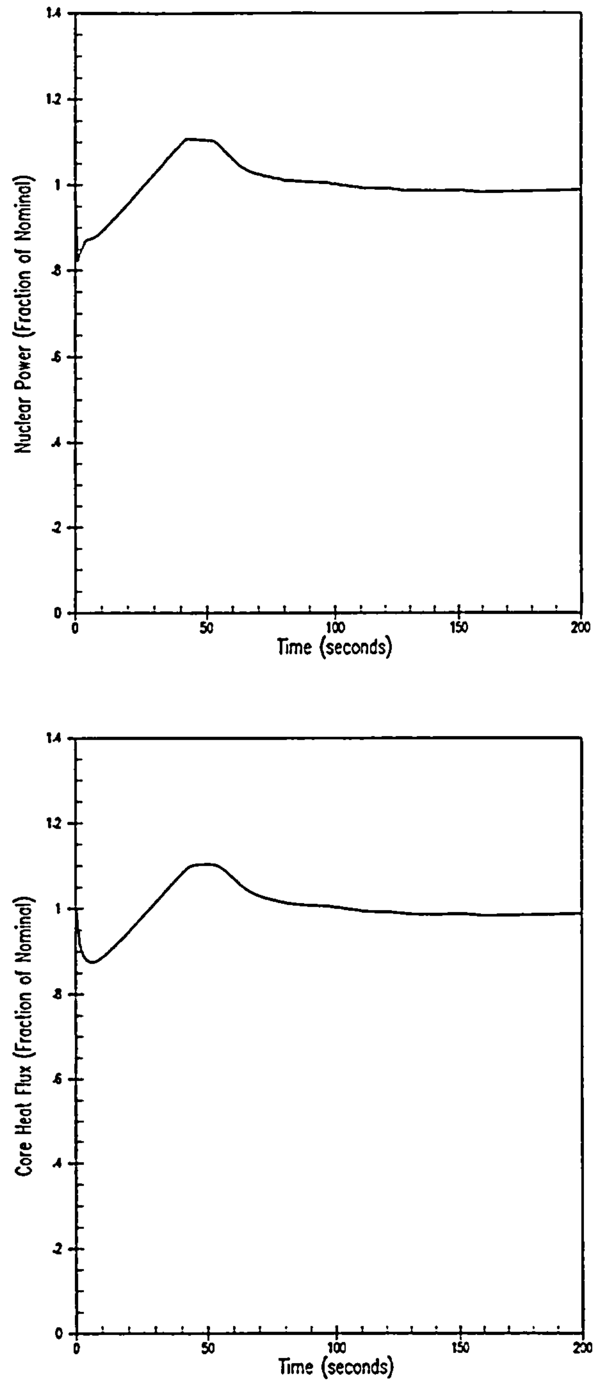


Figure 6.3-27

Dropped Rod Transient with Automatic Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 200 pcm at BOL (small negative MTC)

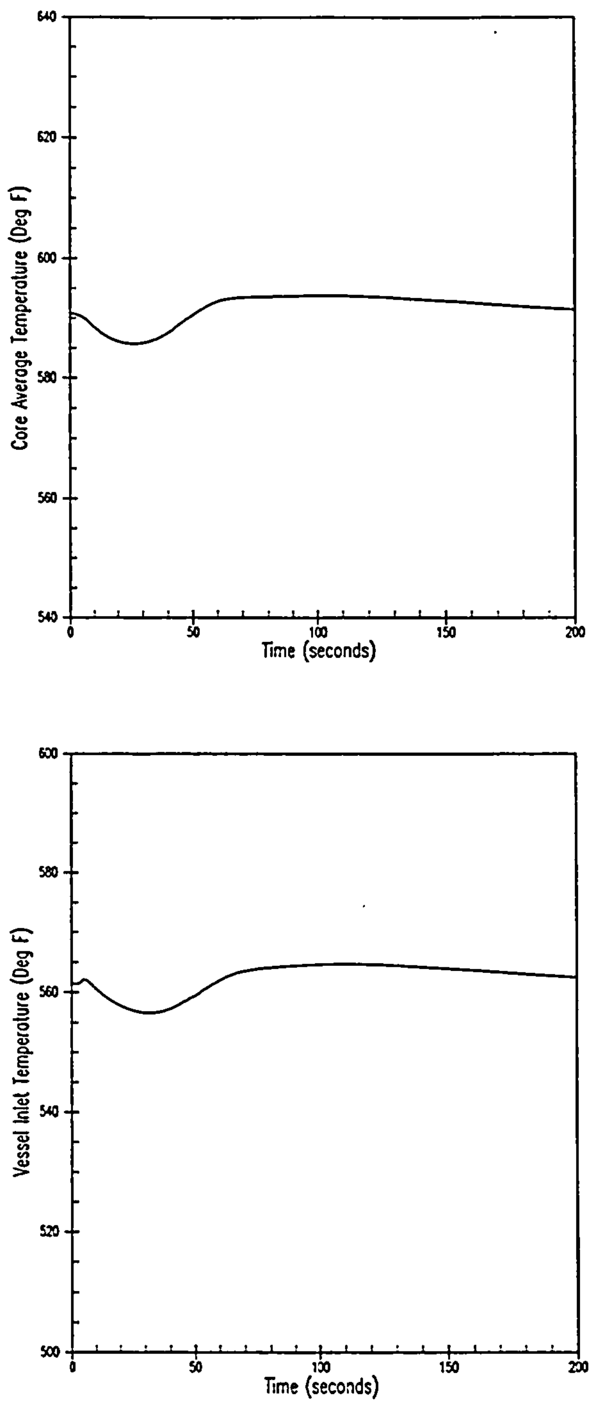


Figure 6.3-28

Dropped Rod Transient with Automatic Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 200 pcm at BOL (small negative MTC)

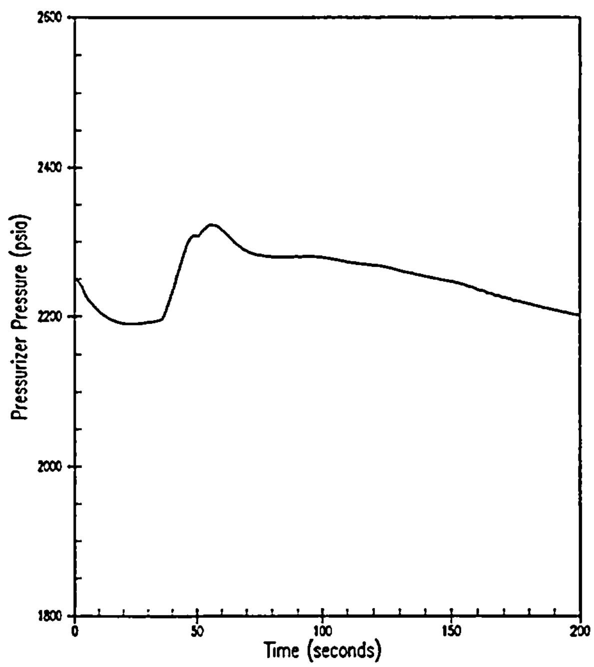


Figure 6.3-29

Dropped Rod Transient with Automatic Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 200 pcm at BOL (small negative MTC)

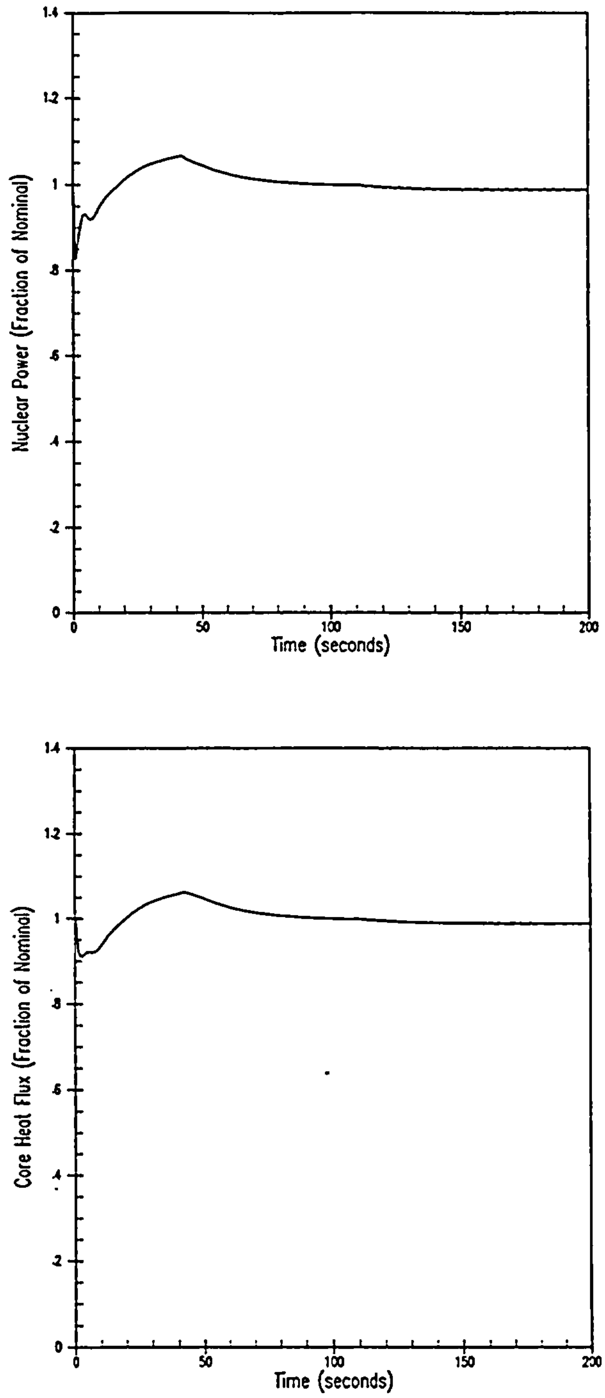


Figure 6.3-30

Dropped Rod Transient with Automatic Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 200 pcm at EOL (large negative MTC)

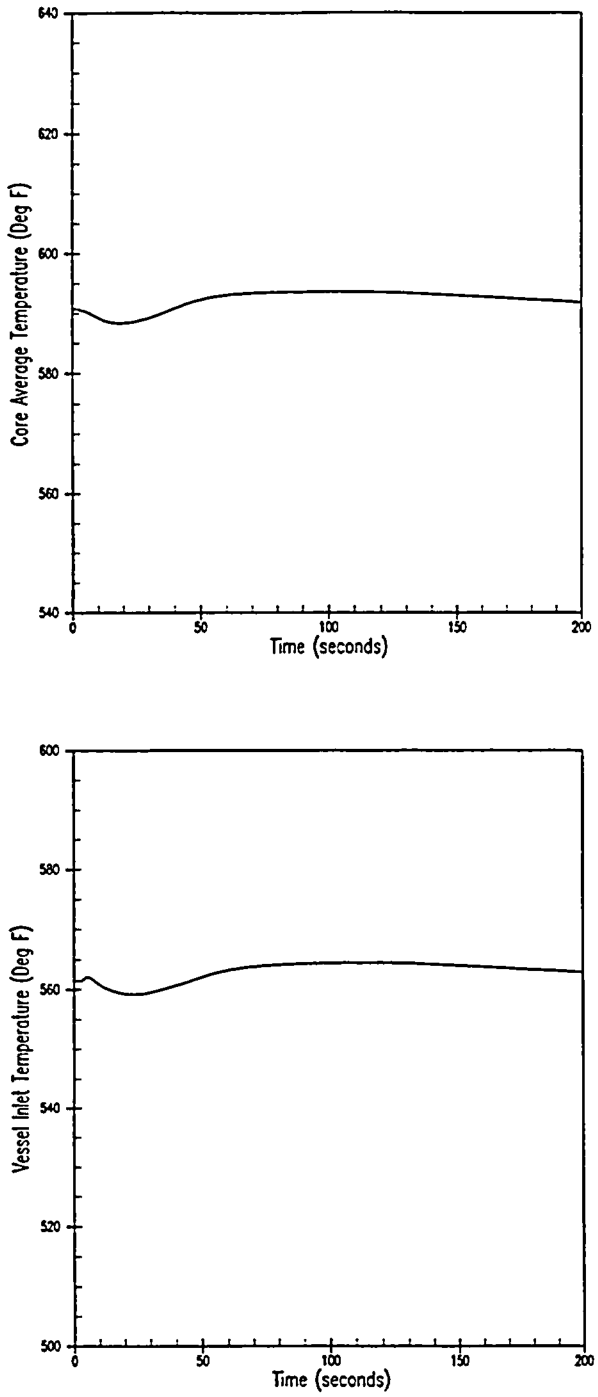


Figure 6.3-31

Dropped Rod Transient with Automatic Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 200 pcm at EOL (large negative MTC)

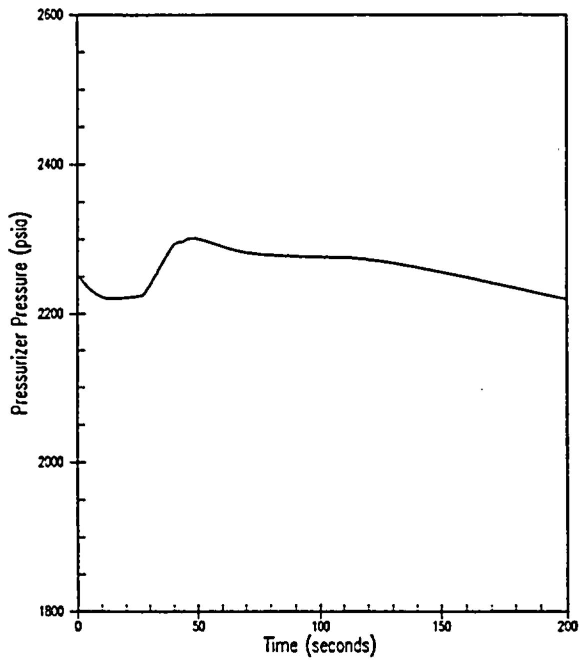
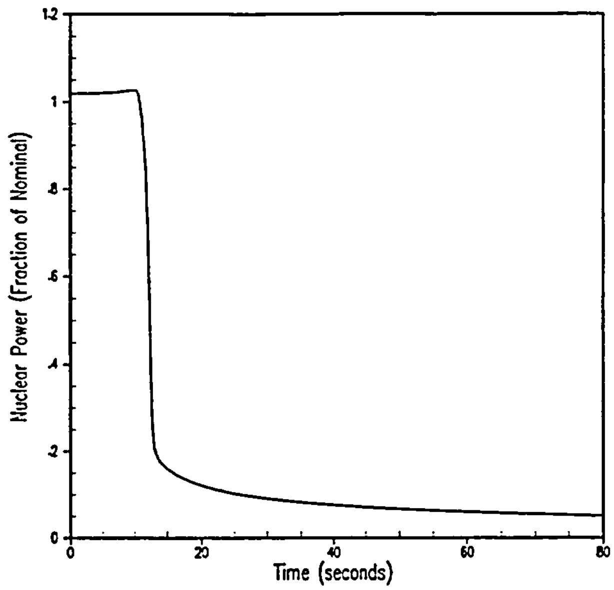


Figure 6.3-32

Dropped Rod Transient with Automatic Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 200 pcm at EOL (large negative MTC)



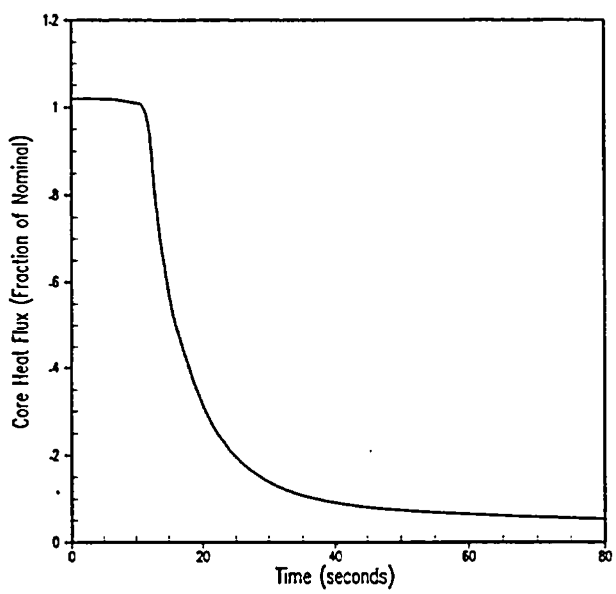
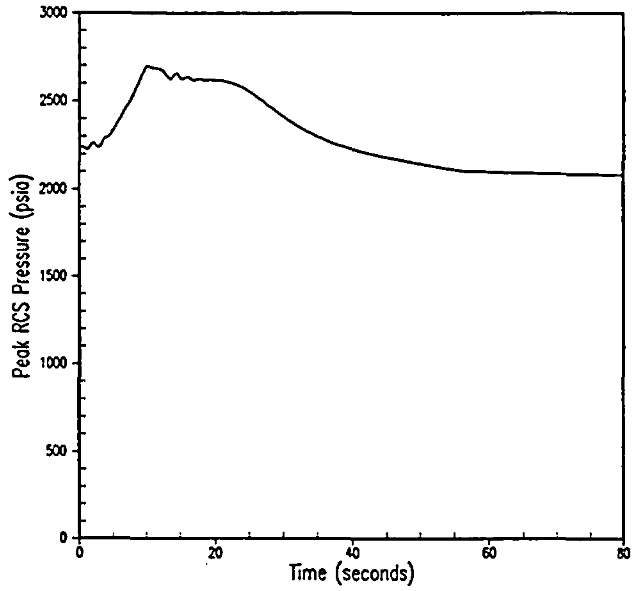


Figure 6.3-33

Loss-of-Load/Turbine Trip, Peak RCS Pressure Case – Nuclear Power and Core Heat Flux



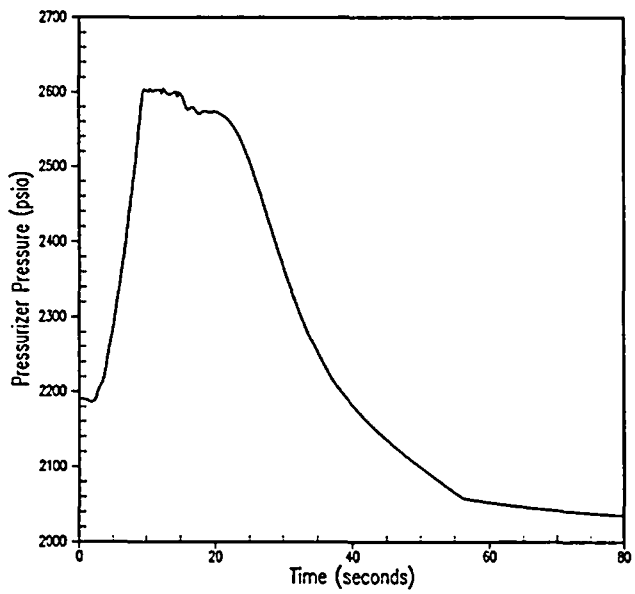
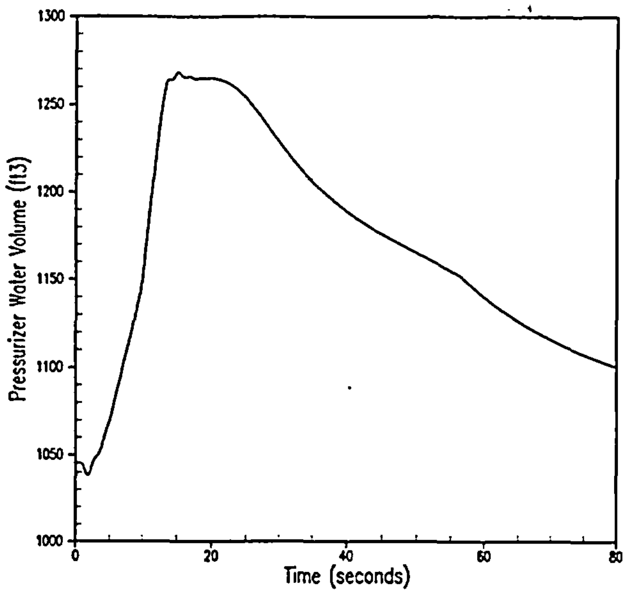


Figure 6.3-34

Loss-of-Load/Turbine Trip, Peak RCS Pressure Case – Peak RCS Pressure and Pressurizer Pressure



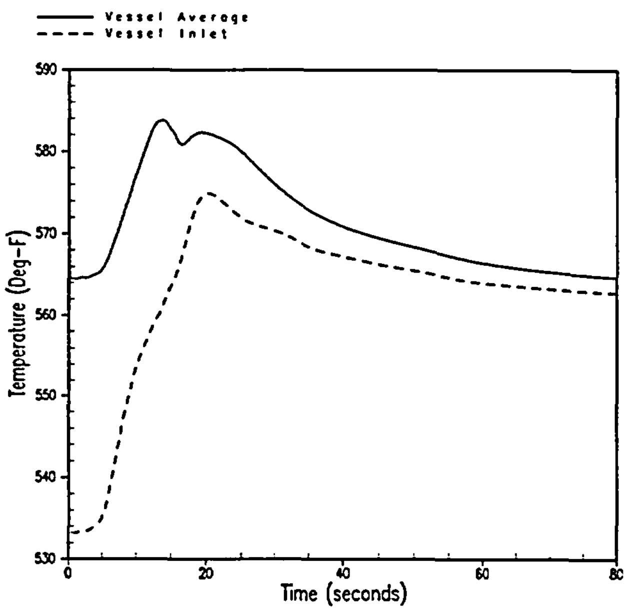
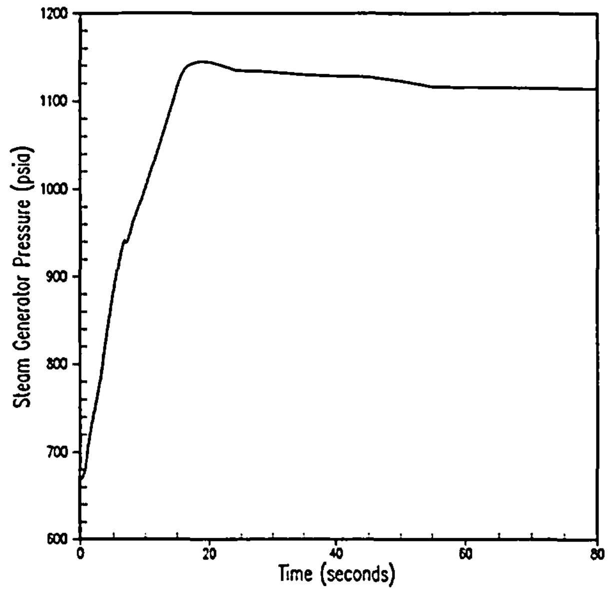


Figure 6.3-35

Loss-of-Load/Turbine Trip, Peak RCS Pressure Case – Pressurizer Water Volume and Vessel Average & Vessel Inlet Temperature



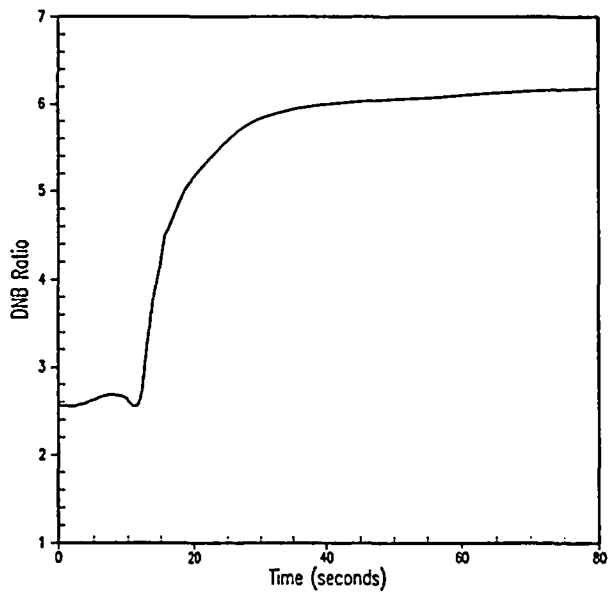
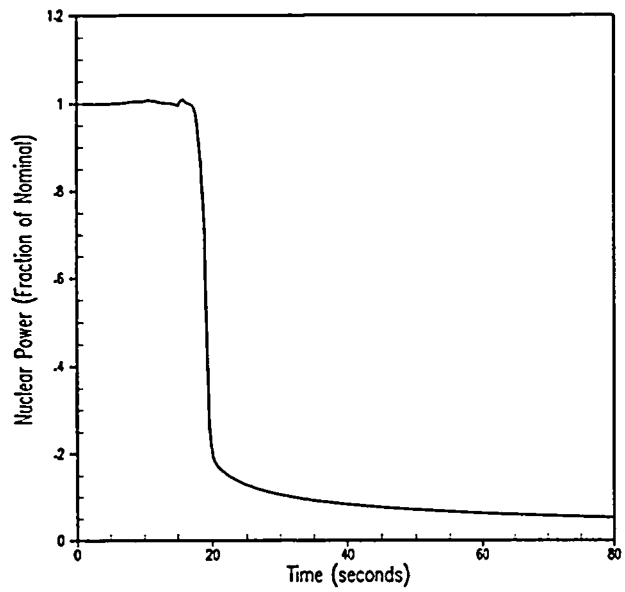


Figure 6.3-36

Loss-of-Load/Turbine Trip, Peak RCS Pressure – Steam Generator Pressure and DNBR



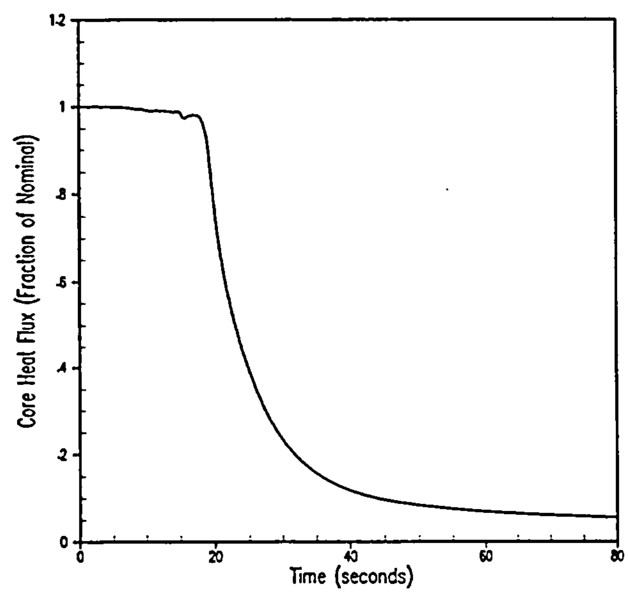


Figure 6.3-37

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Nuclear Power and Core Heat Flux

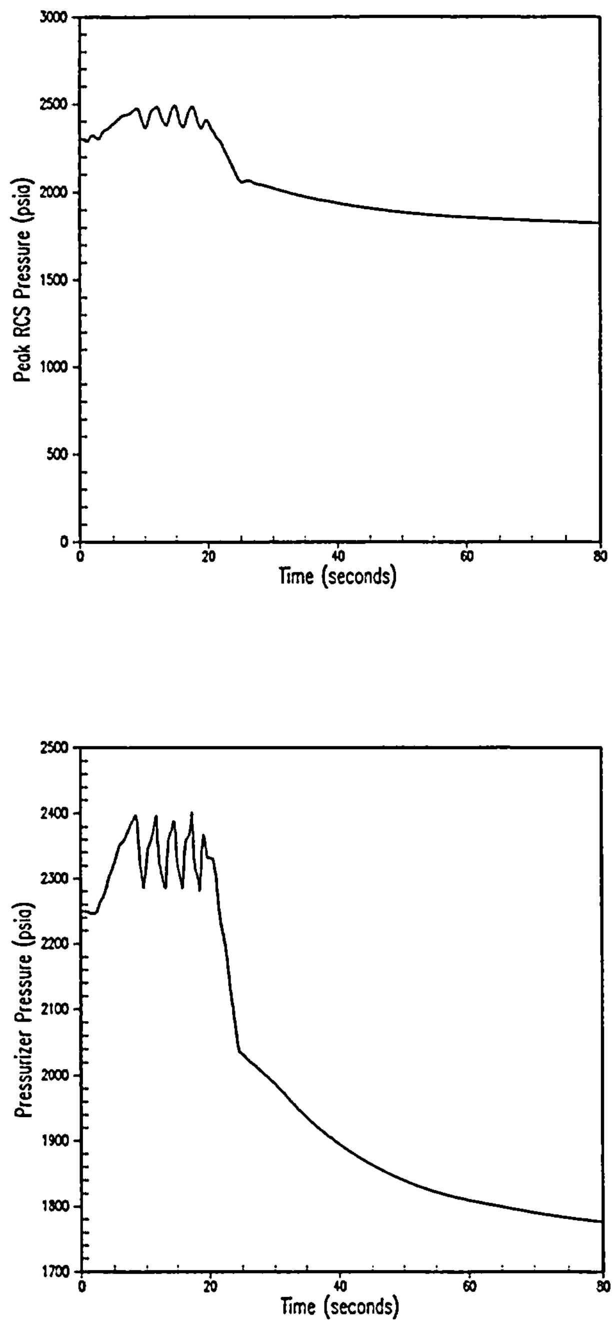
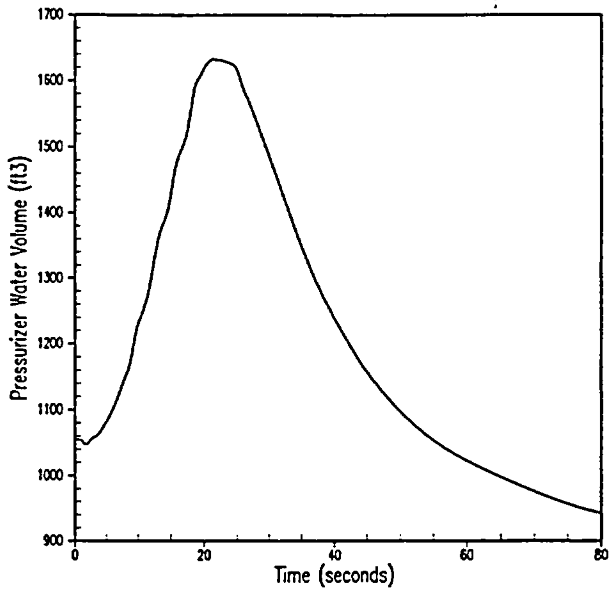


Figure 6.3-38

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Peak RCS Pressure and Pressurizer Pressure



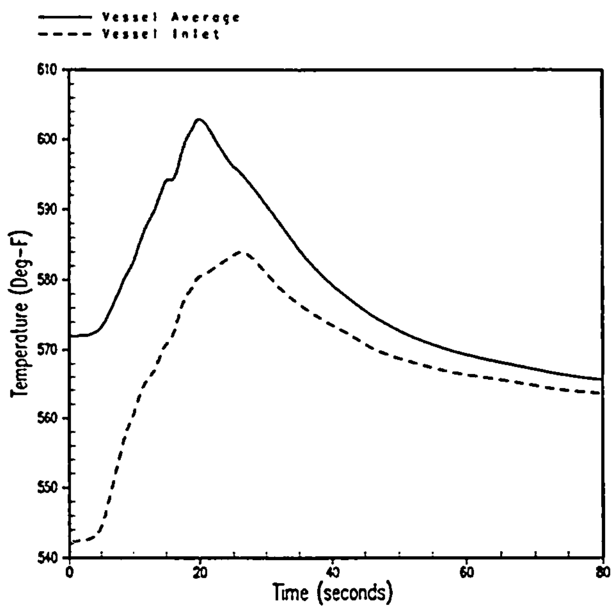
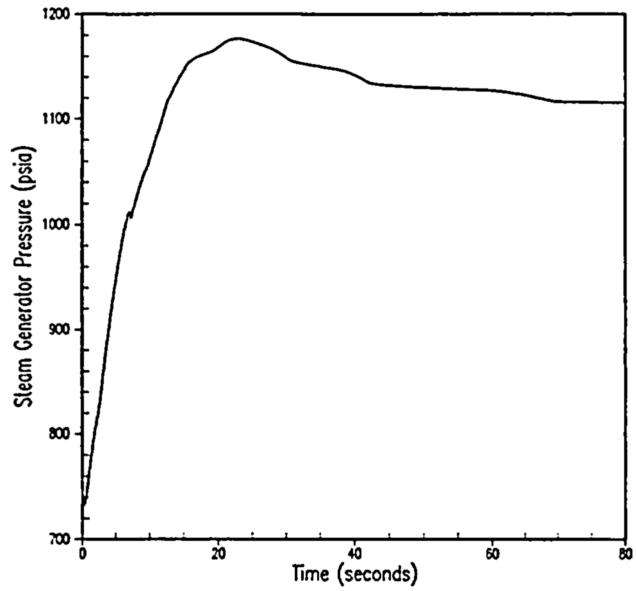


Figure 6.3-39

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Pressurizer Water Volume and Vessel Average & Vessel Inlet Temperature



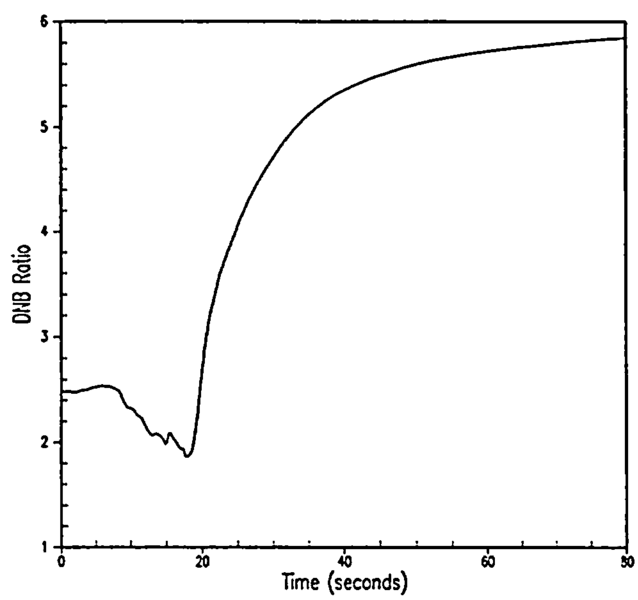


Figure 6.3-40

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Steam Generator Pressure and DNBR

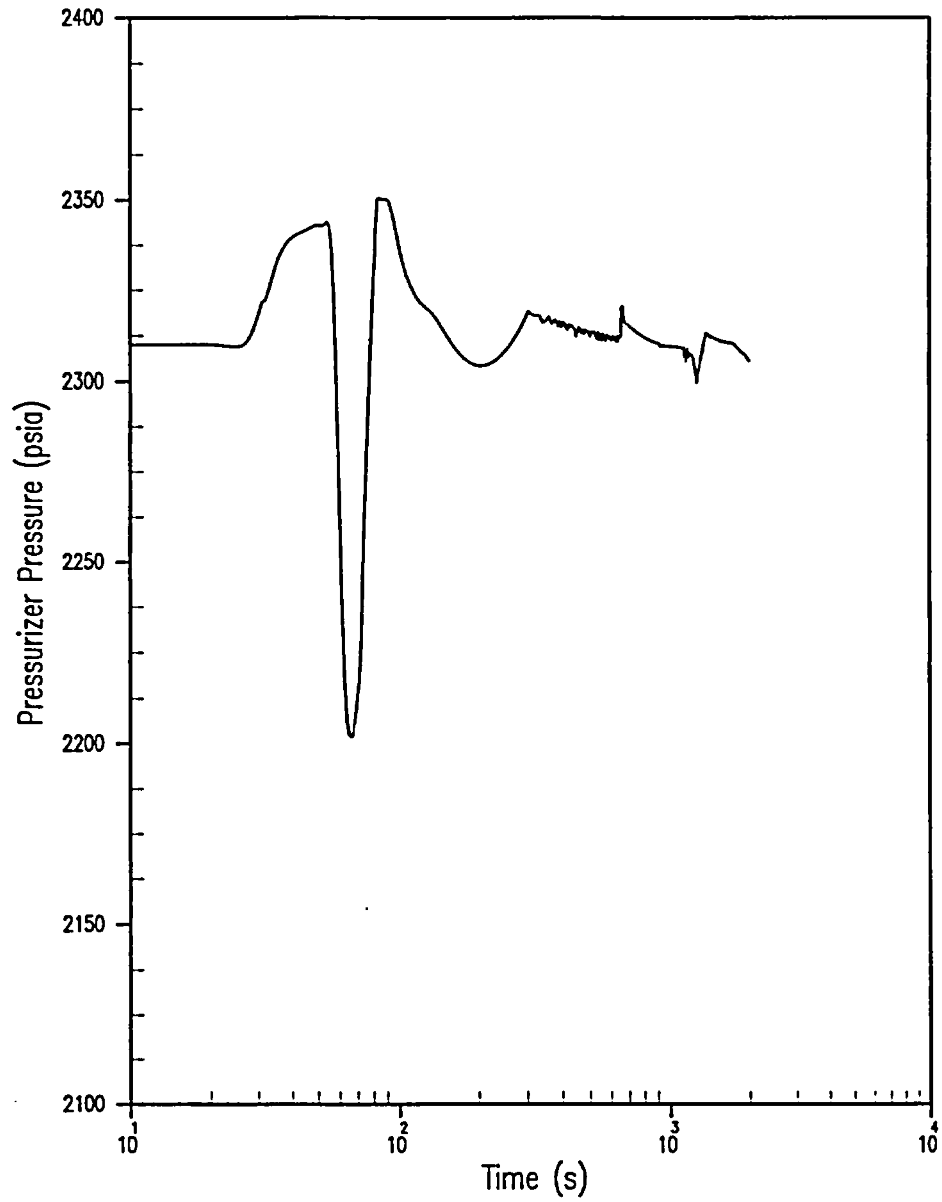


Figure 6.3-41

LONF (Pressurizer Pressure vs. Time)

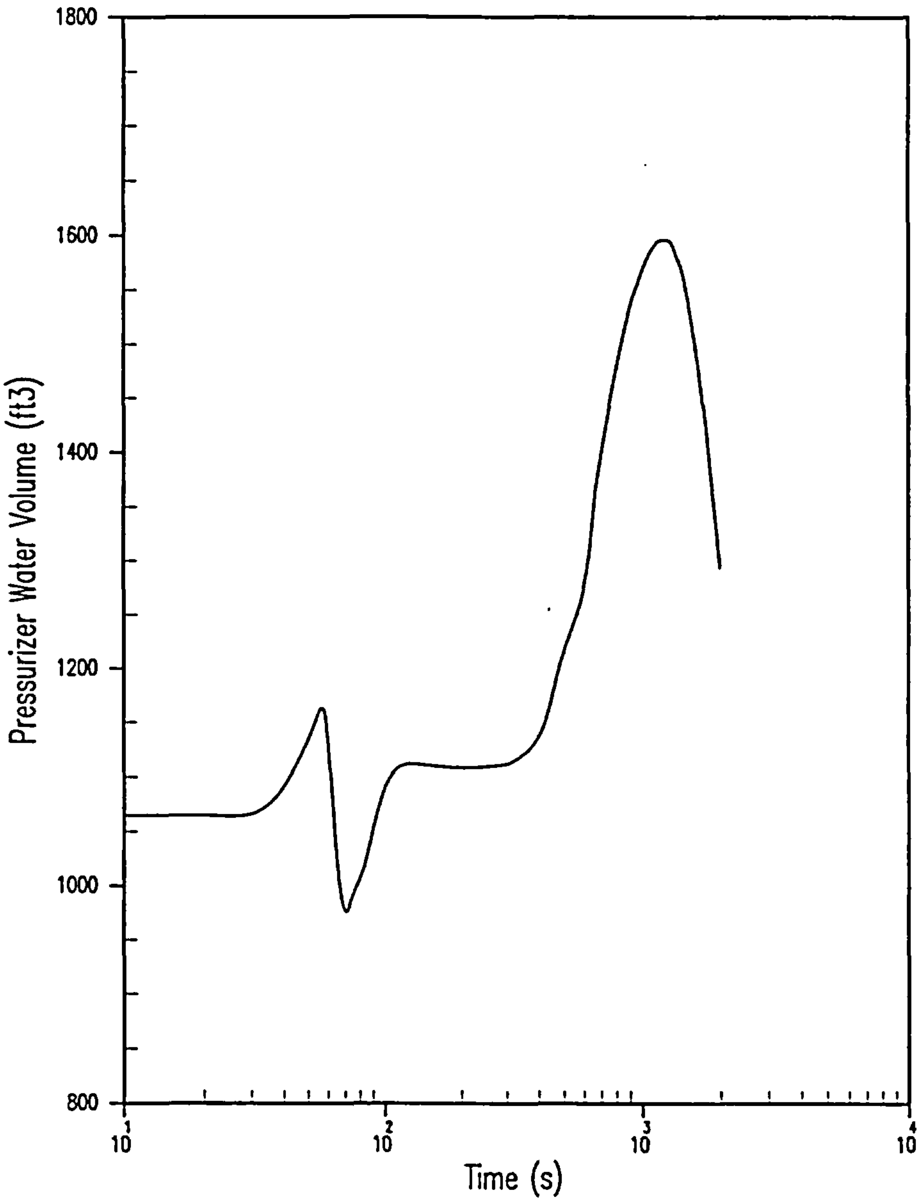


Figure 6.3-42

LONF (Pressurizer Water Volume vs. Time)

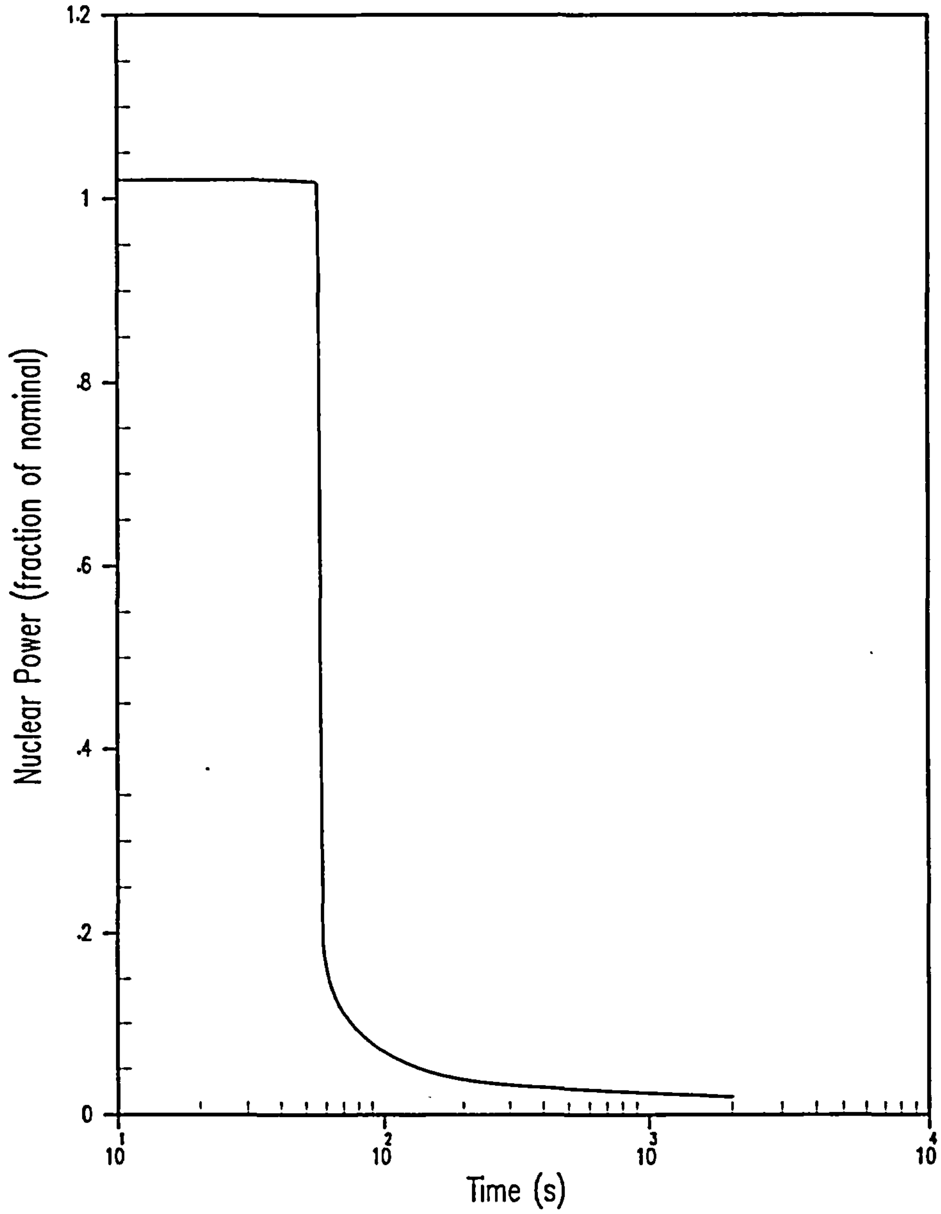


Figure 6.3-43

LONF (Nuclear Power vs. Time)

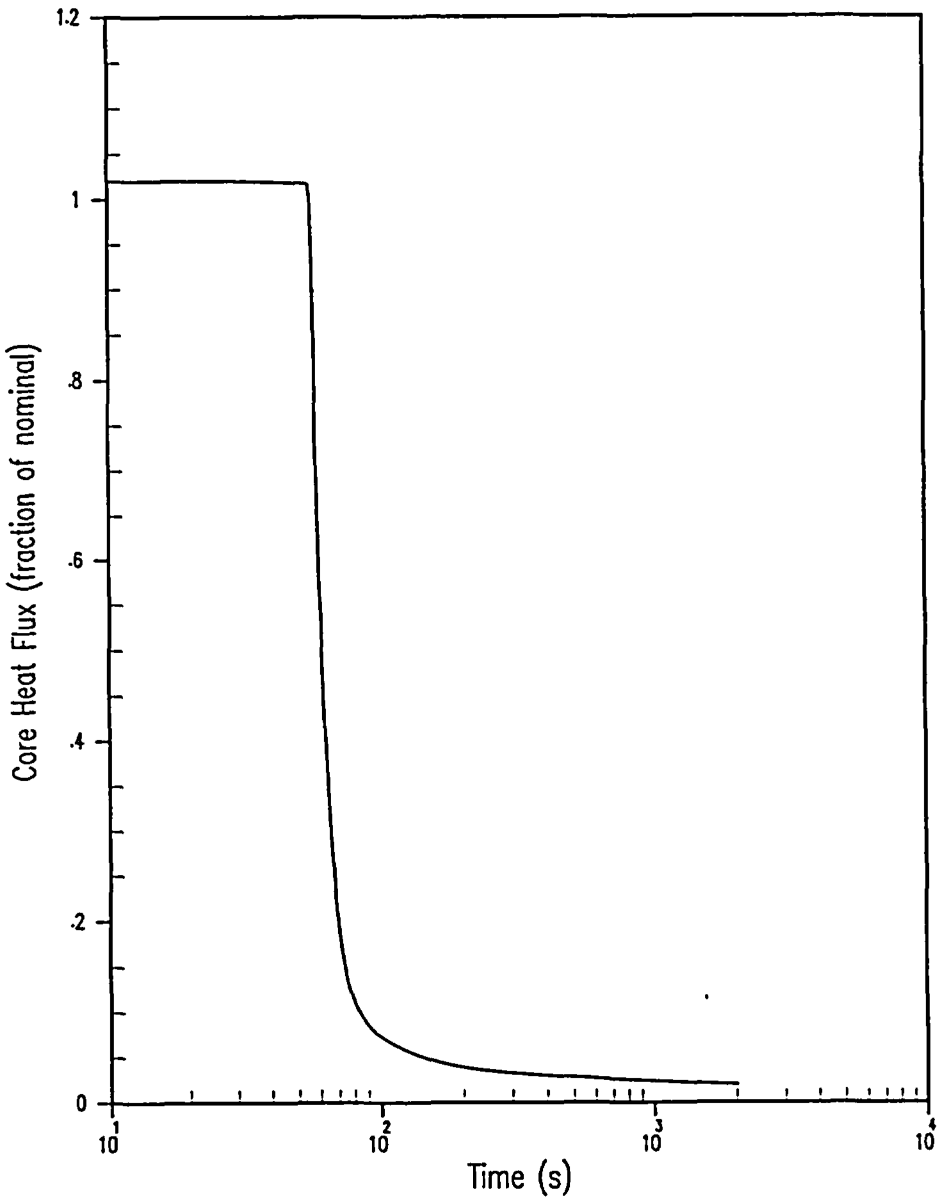


Figure 6.3-44

LONF (Core Heat Flux vs. Time)

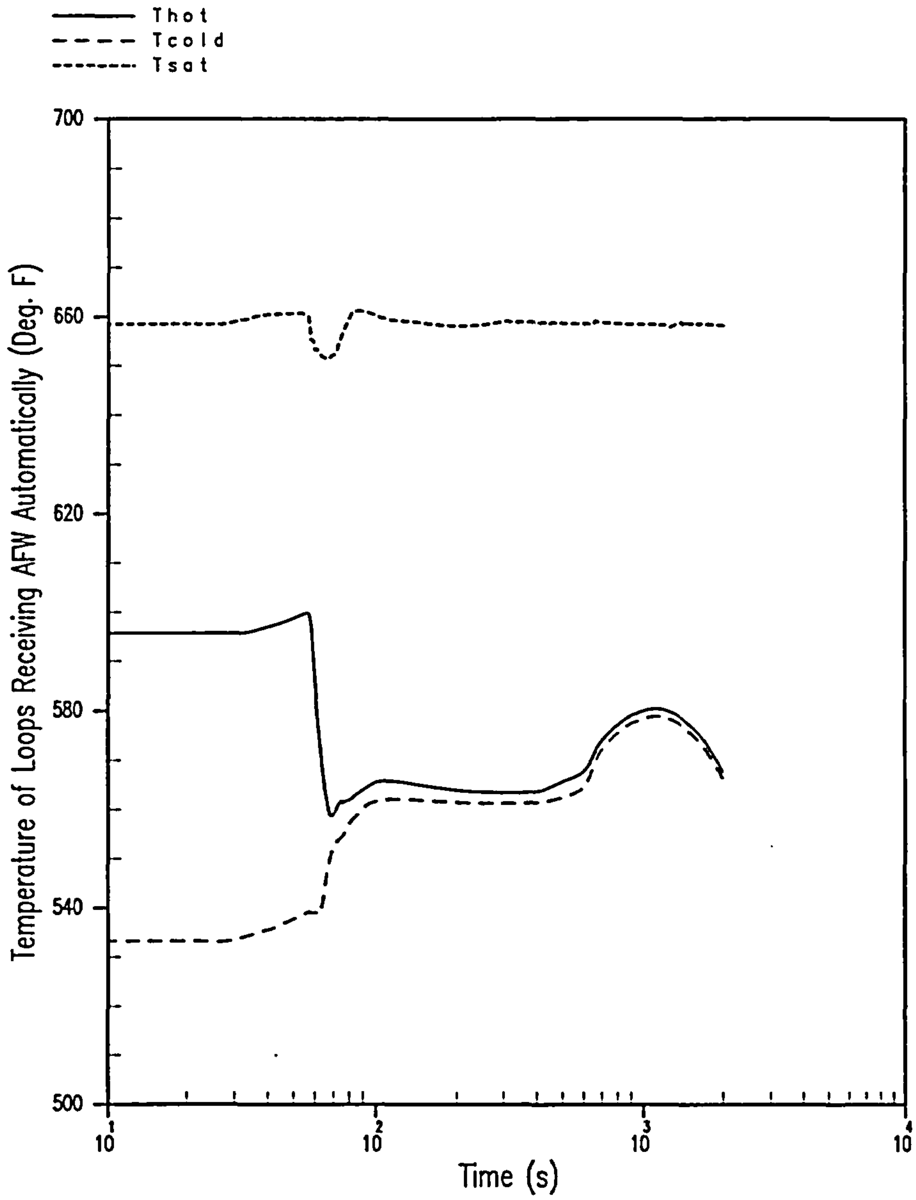


Figure 6.3-45

LONF (RCS Temperatures for Loops Receiving Automatic AFW Flow vs. Time)

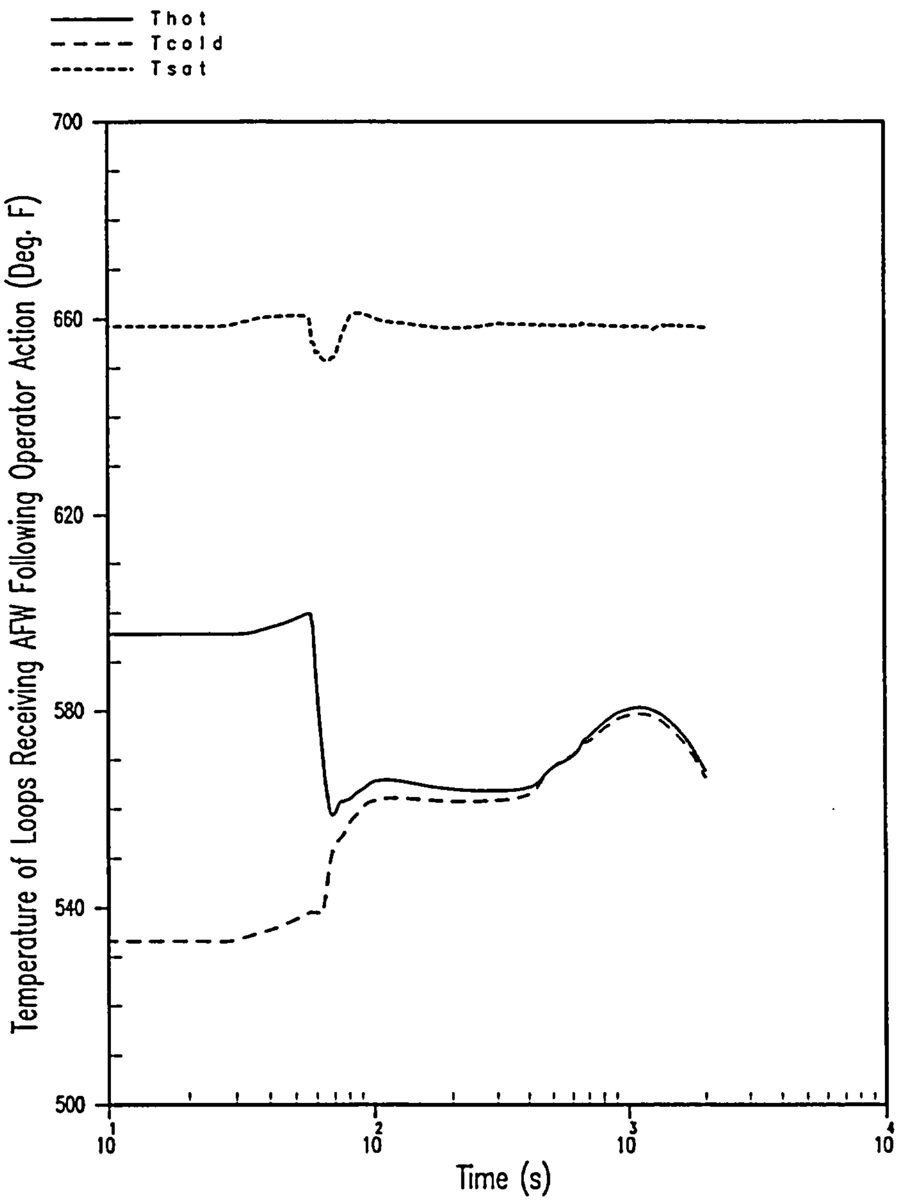


Figure 6.3-46

LONF (RCS Temperatures for Loops Receiving AFW Flow Following Operator Action vs. Time)

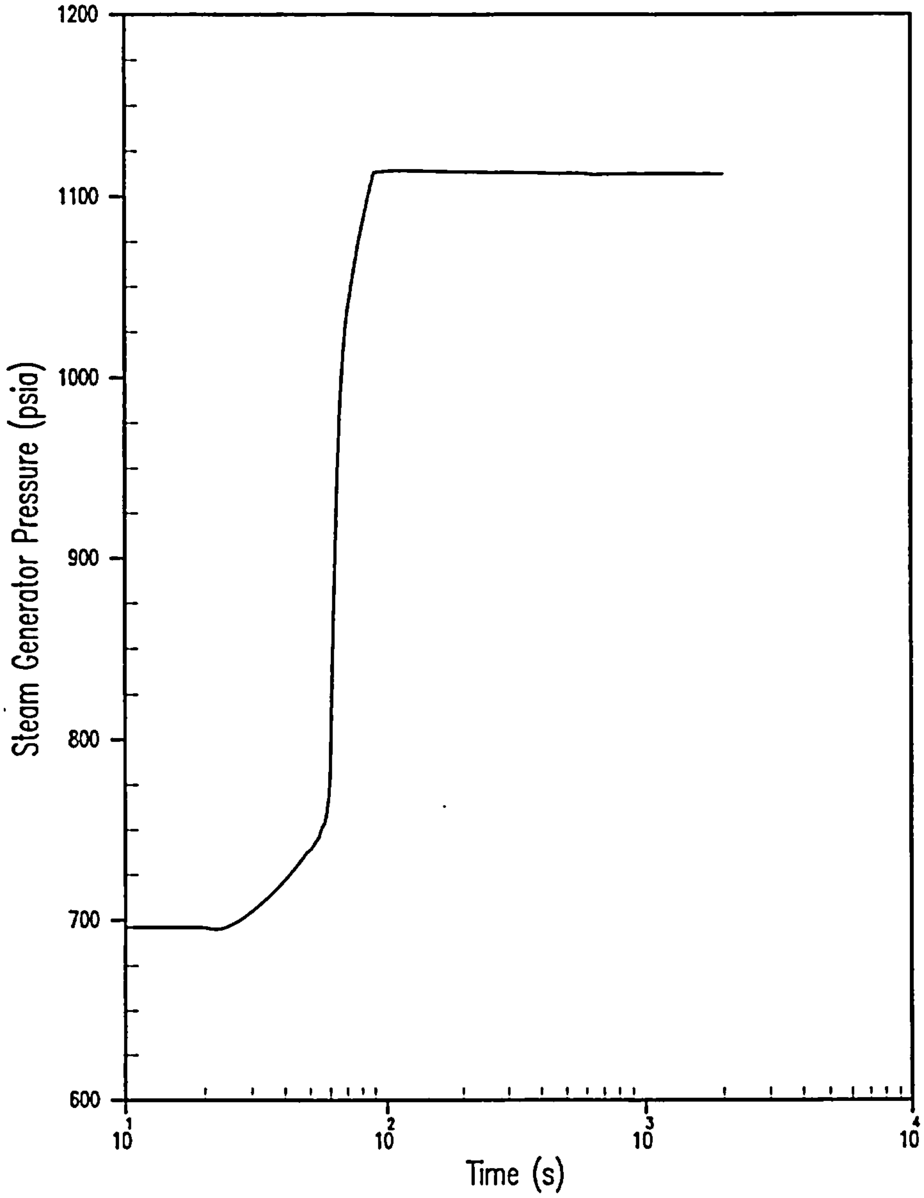


Figure 6.3-47

LONF (Steam Generator Pressure vs. Time)

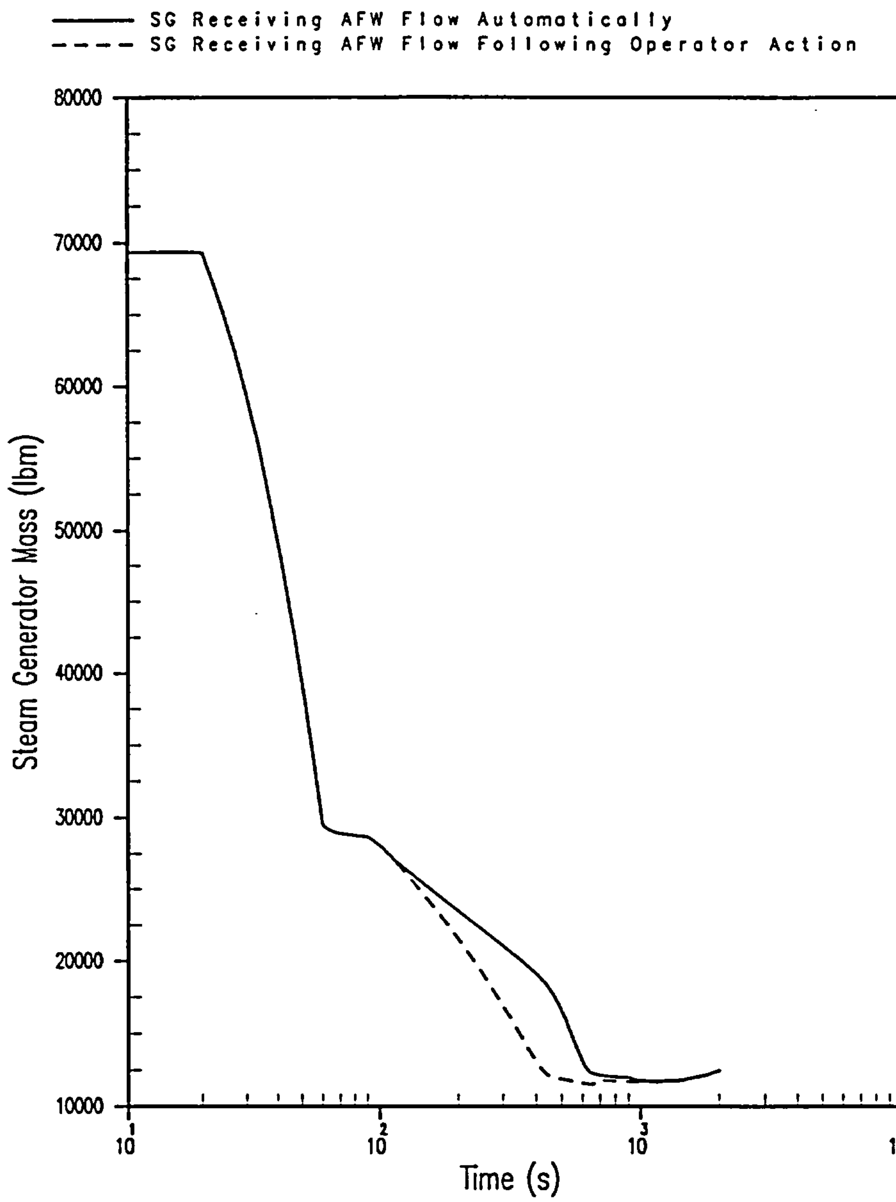


Figure 6.3-48

LONF (Steam Generator Mass vs. Time)

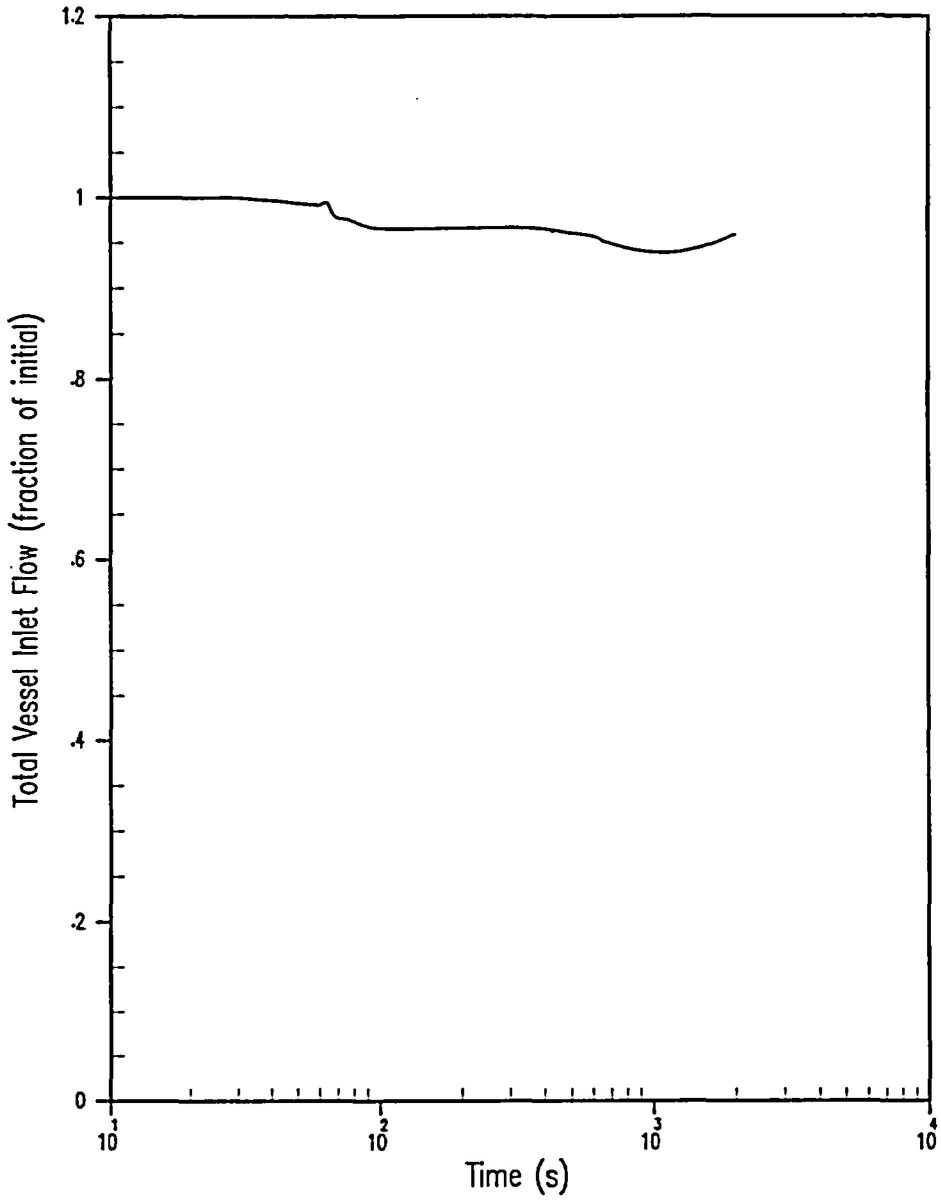


Figure 6.3-49

LONF (Total RCS Flow vs. Time)

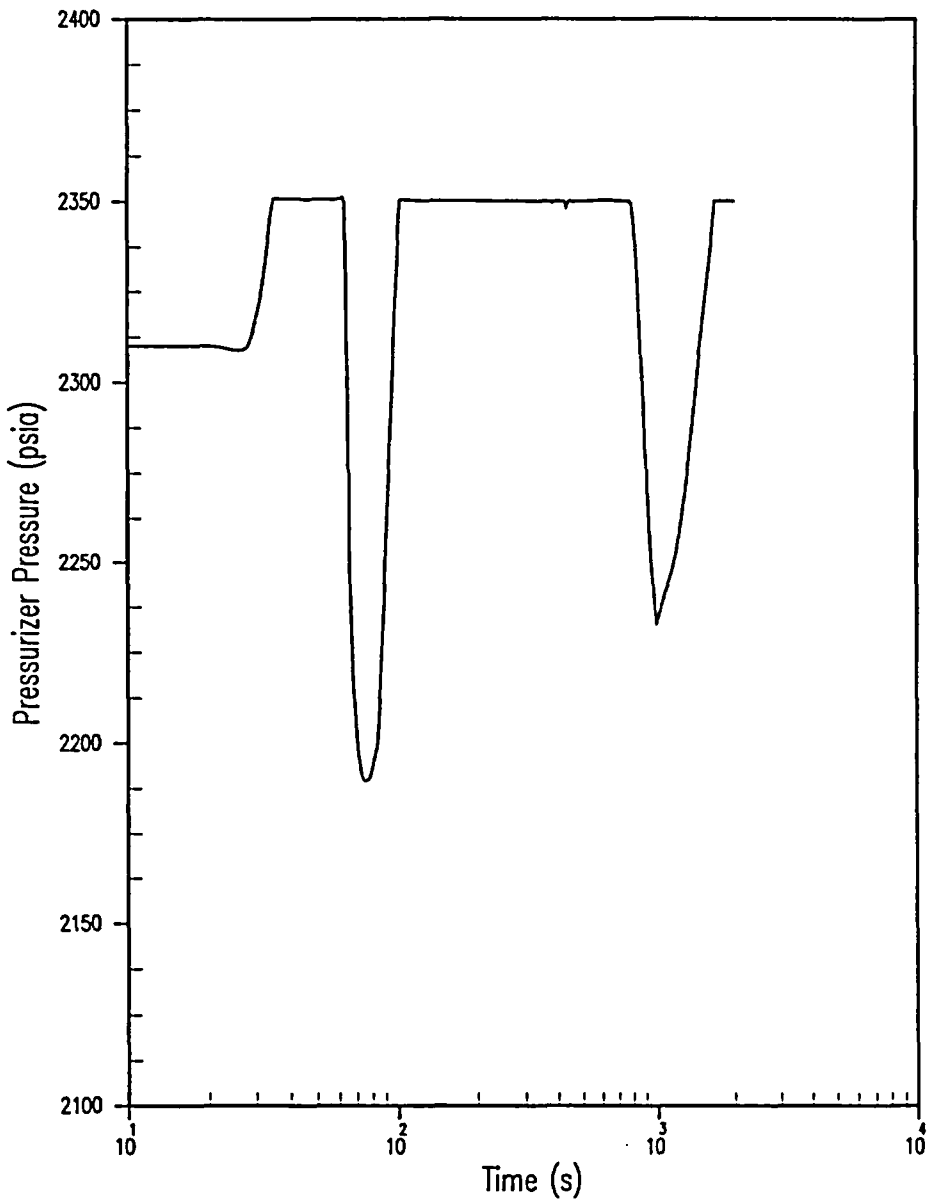


Figure 6.3-50

LOAC to the Plant Auxiliaries

(Pressurizer Pressure vs. Time)

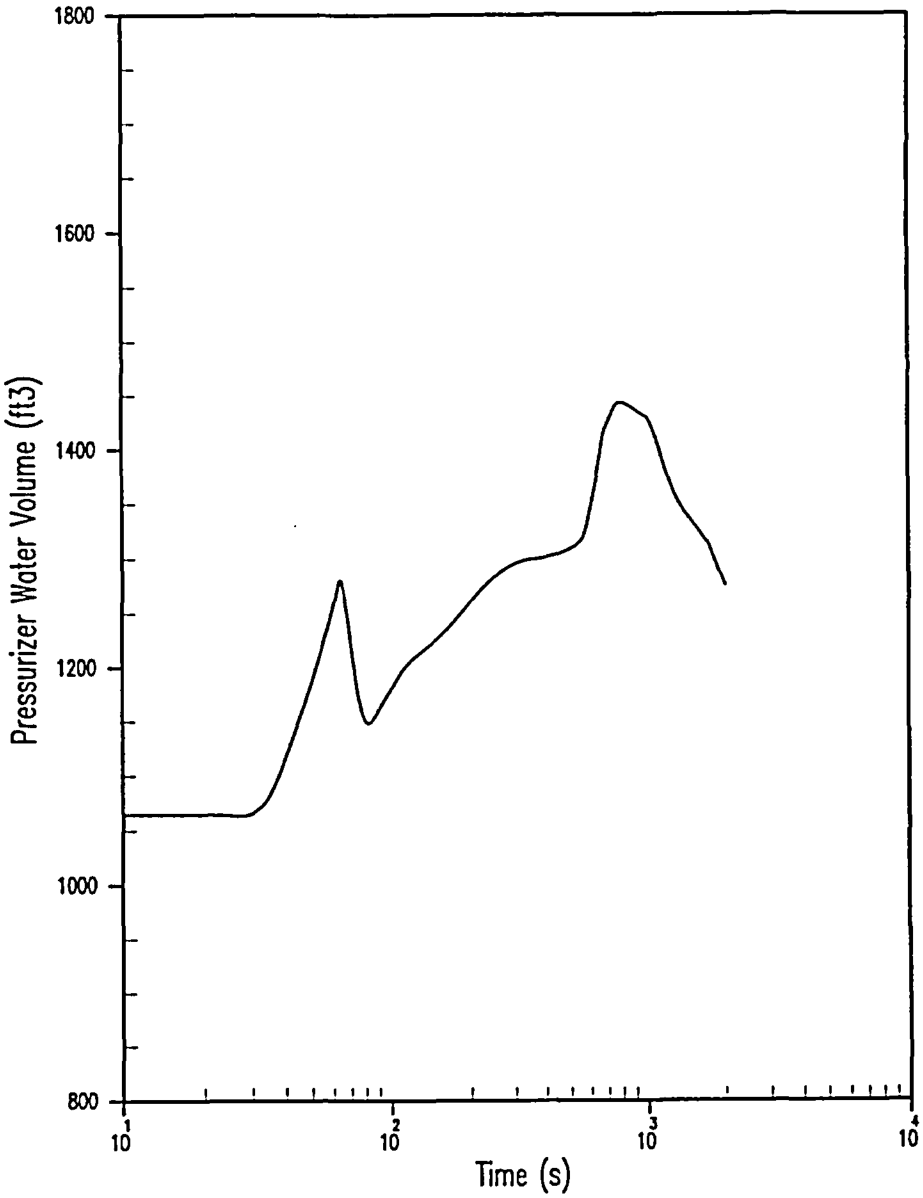


Figure 6.3-51

LOAC to the Plant Auxiliaries

(Pressurizer Water Volume vs. Time)

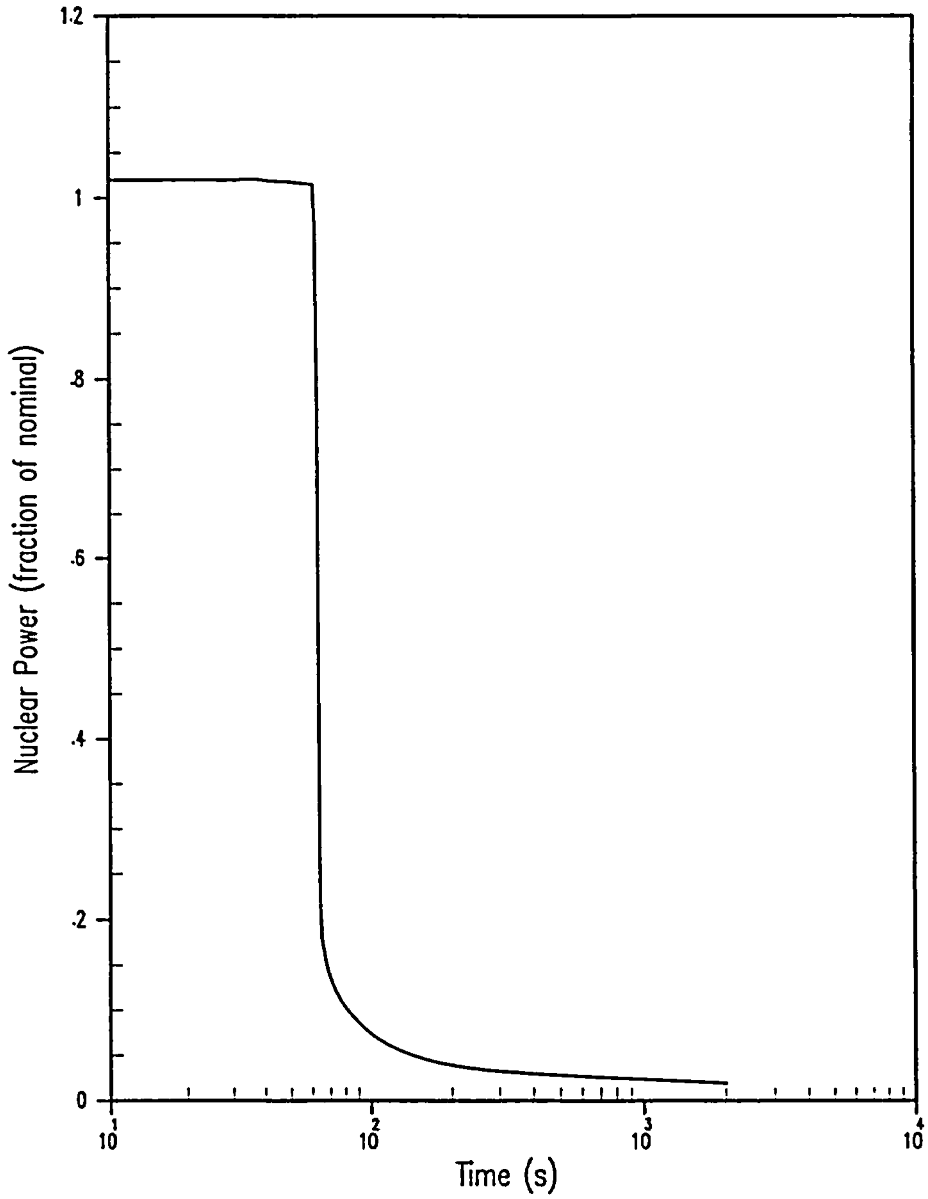


Figure 6.3-52

LOAC to the Plant Auxiliaries

(Nuclear Power vs. Time)

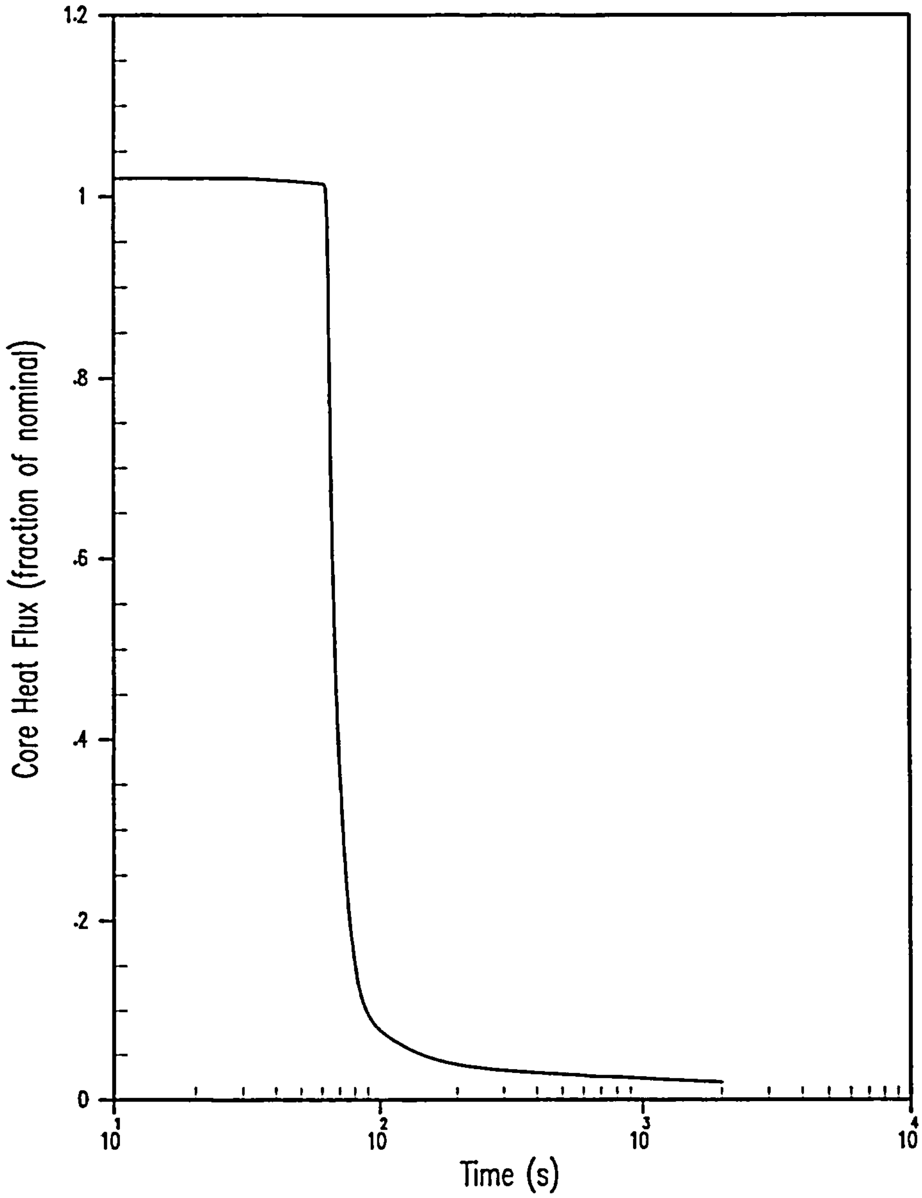


Figure 6.3-53

LOAC to the Plant Auxiliaries

(Core Heat Flux vs. Time)

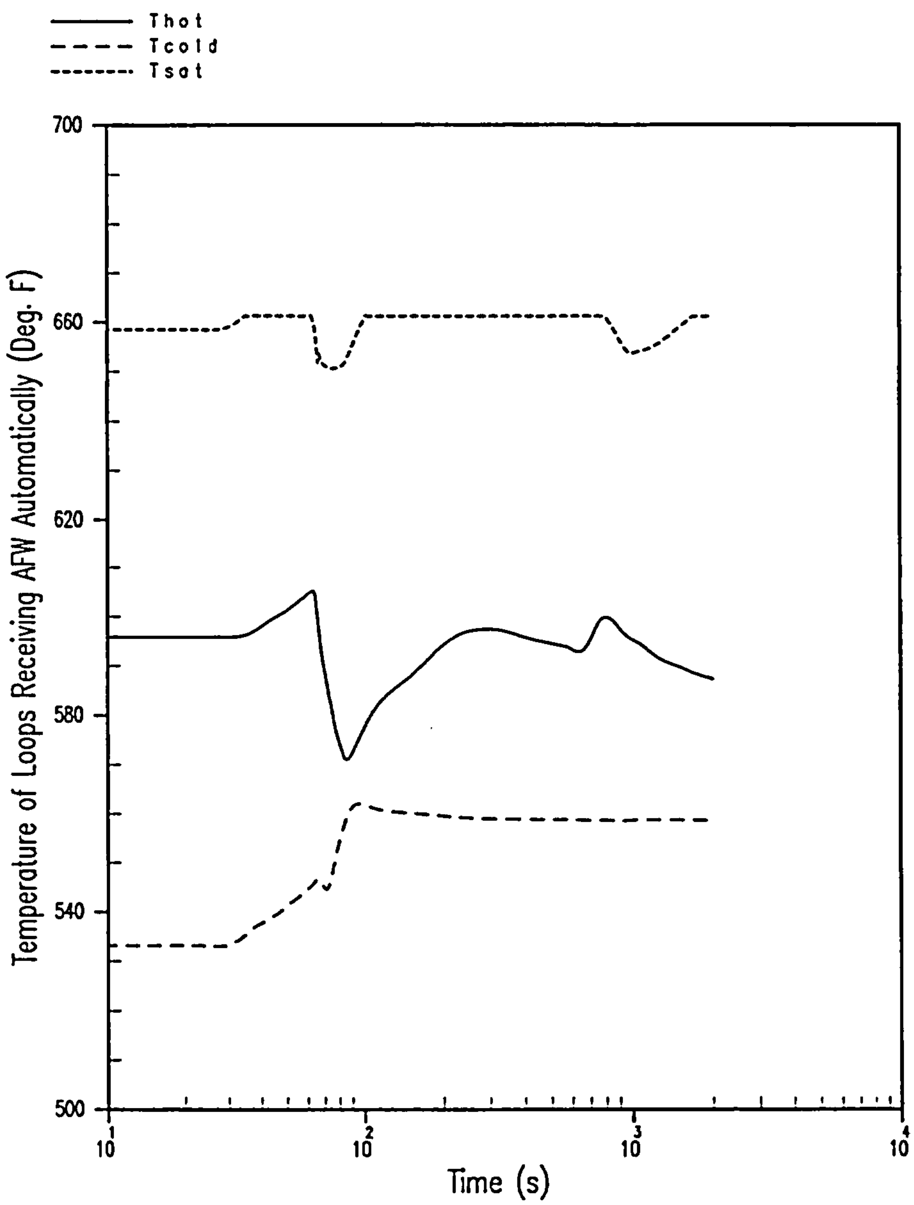


Figure 6.3-54

LOAC to the Plant Auxiliaries

(RCS Temperatures for Loops Receiving Automatic AFW Flow vs. Time)

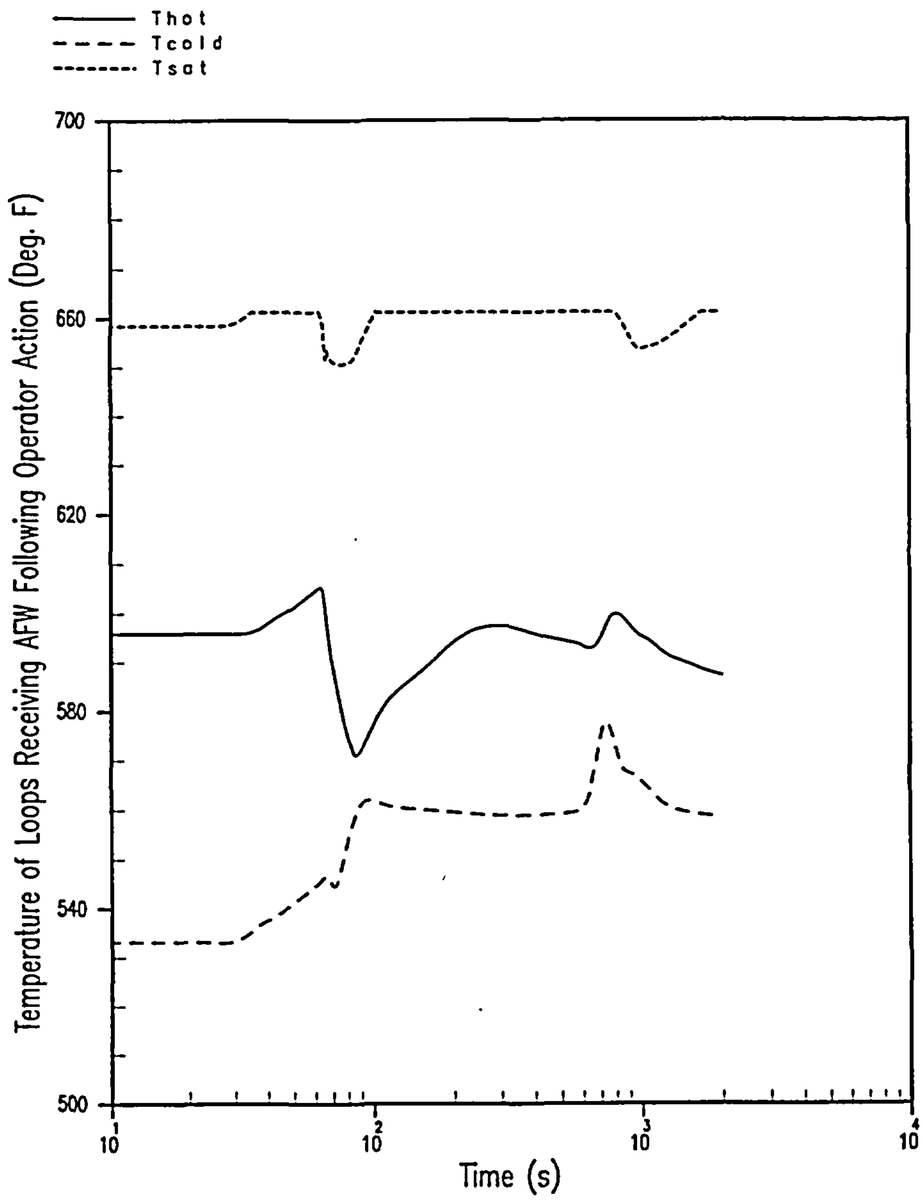


Figure 6.3-55

LOAC to the Plant Auxiliaries

(RCS Temperatures for Loops Receiving AFW Flow Following Operator Action vs. Time)

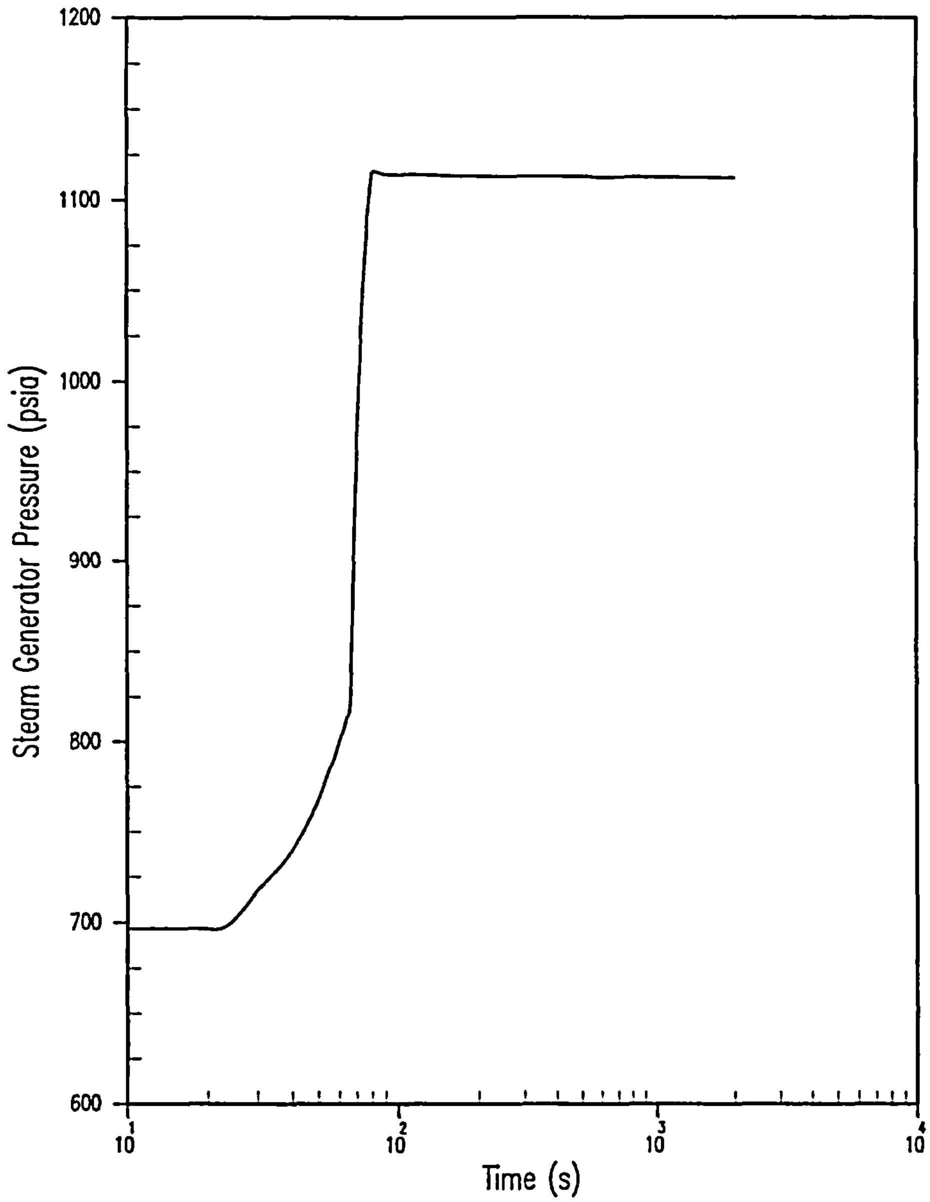


Figure 6.3-56

LOAC to the Plant Auxiliaries

(Steam Generator Pressure vs. Time)

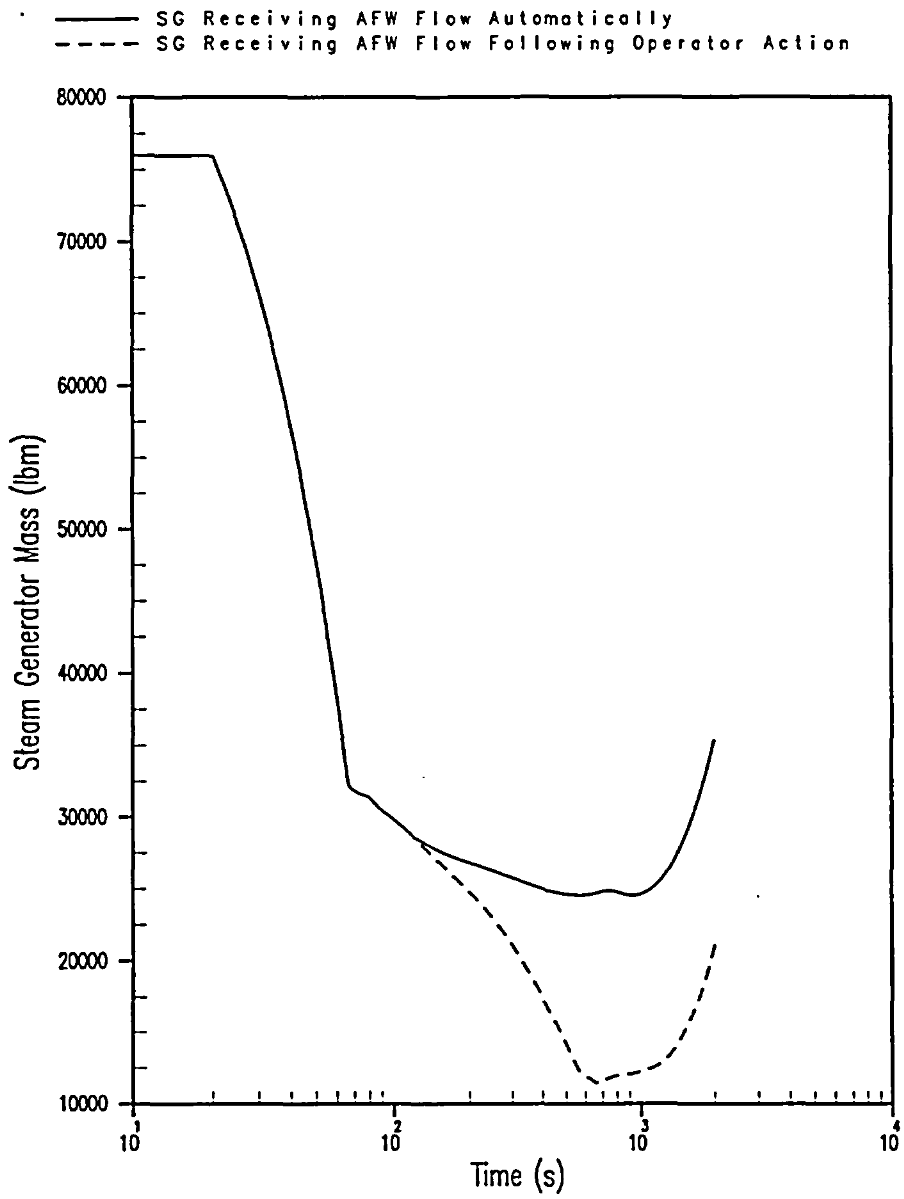


Figure 6.3-57

LOAC to the Plant Auxiliaries

(Steam Generator Mass vs. Time)

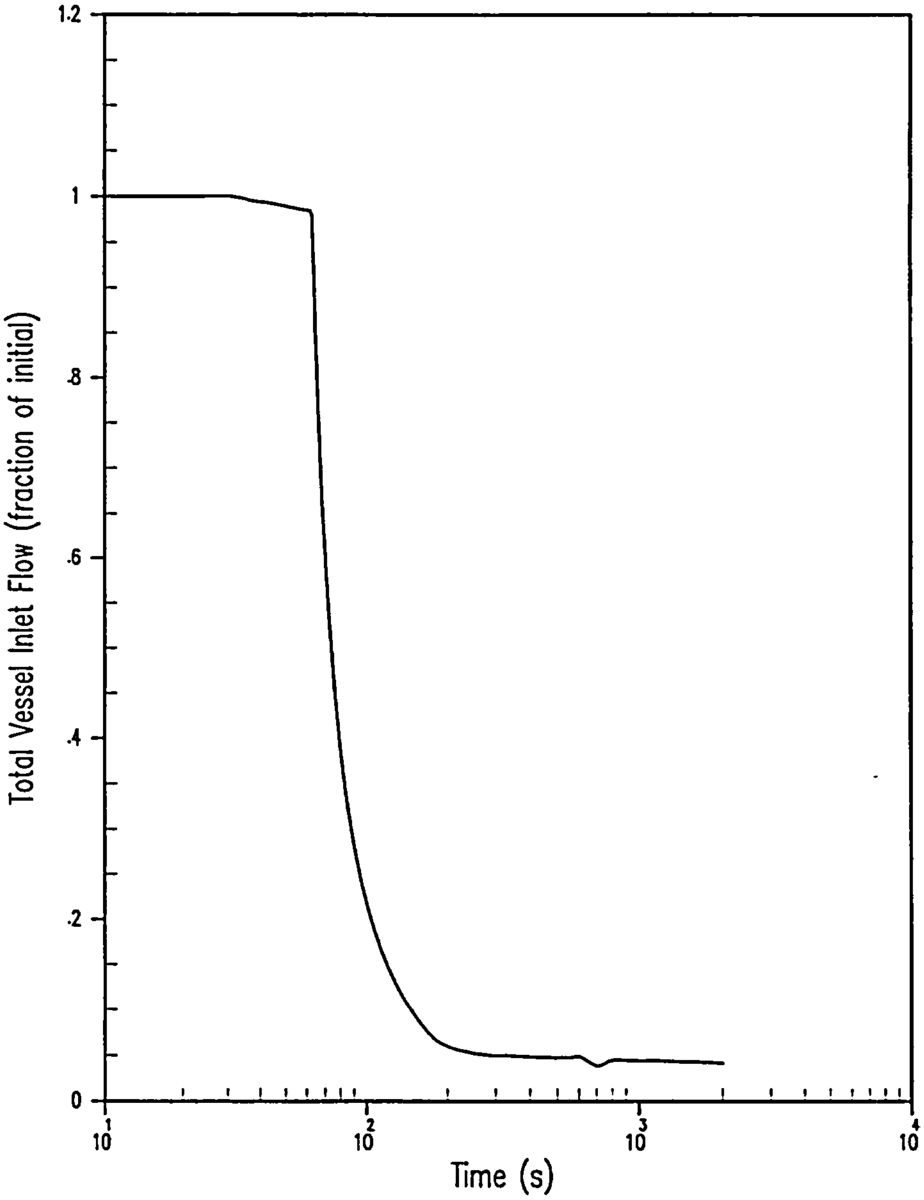
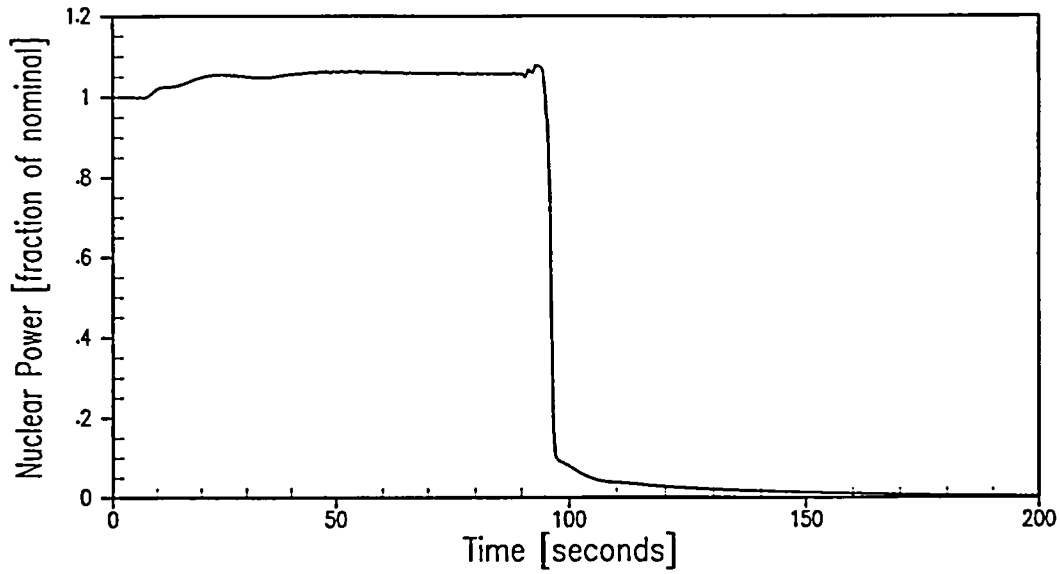


Figure 6.3-58

LOAC to the Plant Auxiliaries

(Total RCS Flow vs. Time)



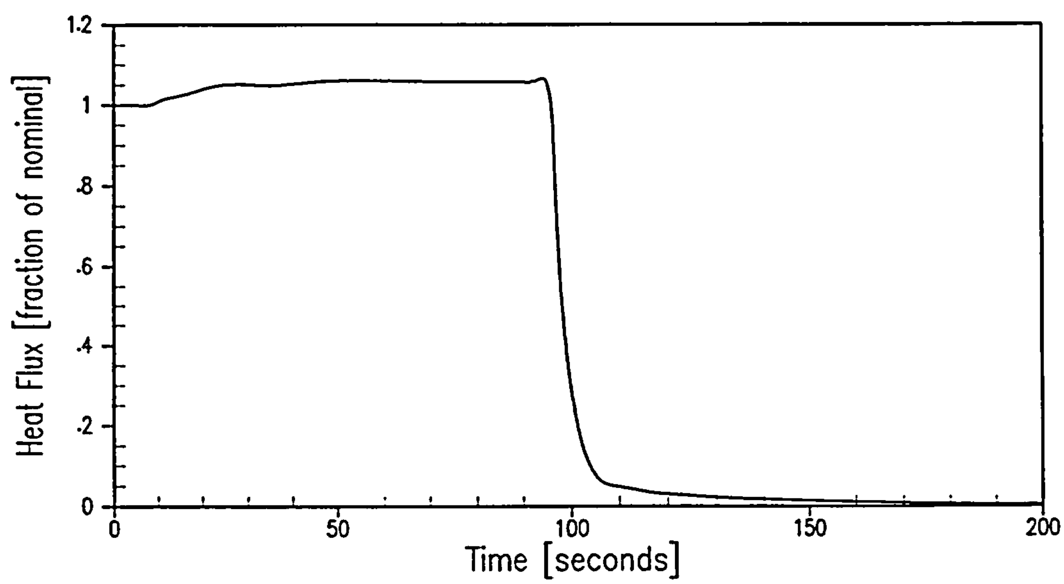


Figure 6.3-59

Feedwater System Malfunction at Full Power

(Nuclear Power and Core Heat Flux vs. Time)

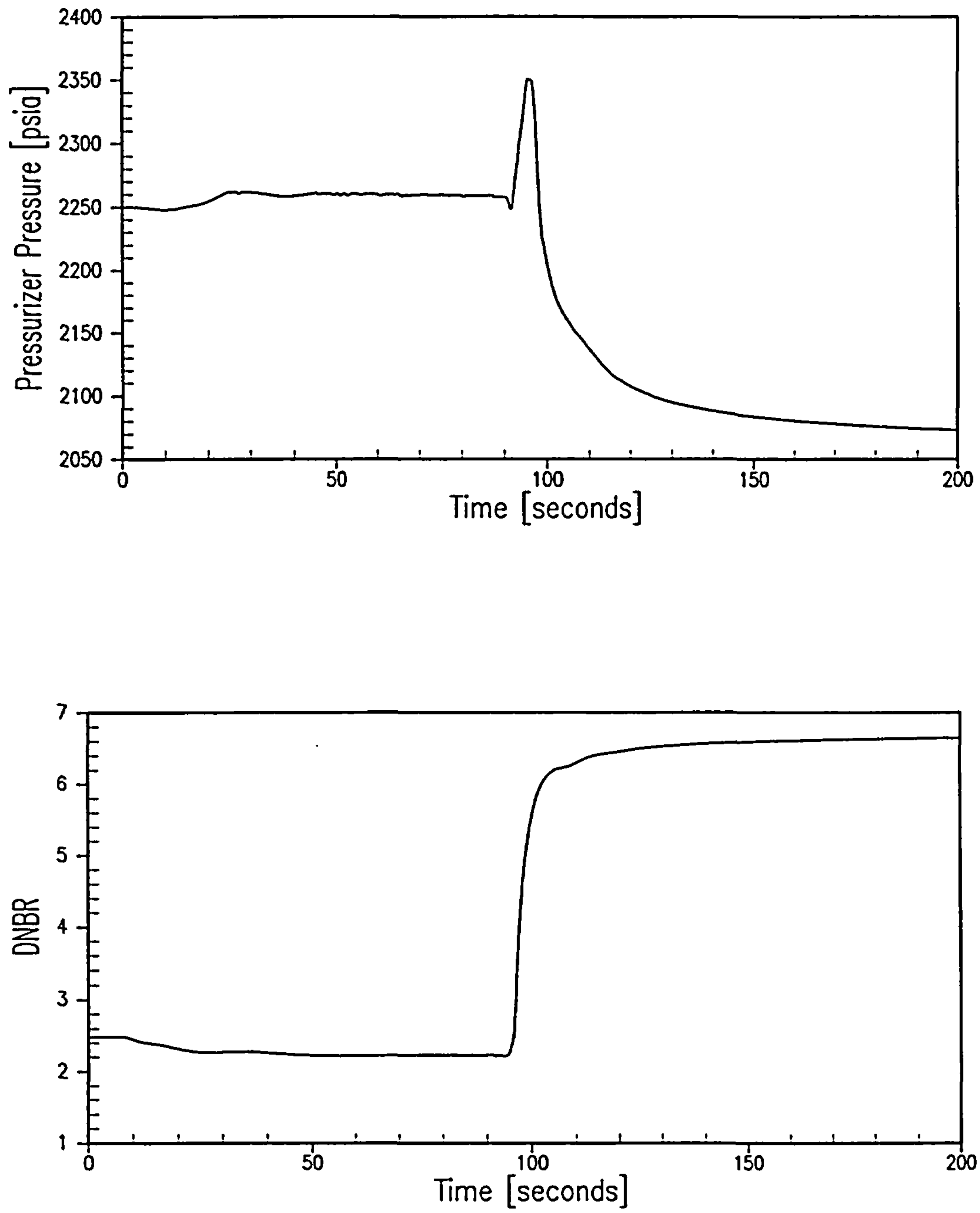
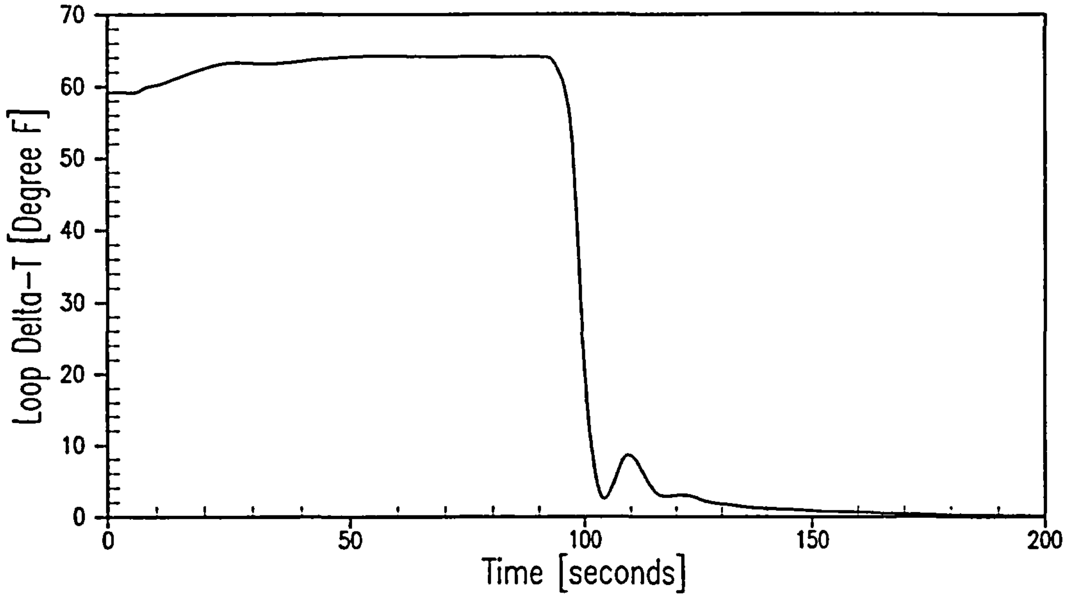


Figure 6.3-60

Feedwater System Malfunction at Full Power

(Pressurizer Pressure and DNBR vs. Time)



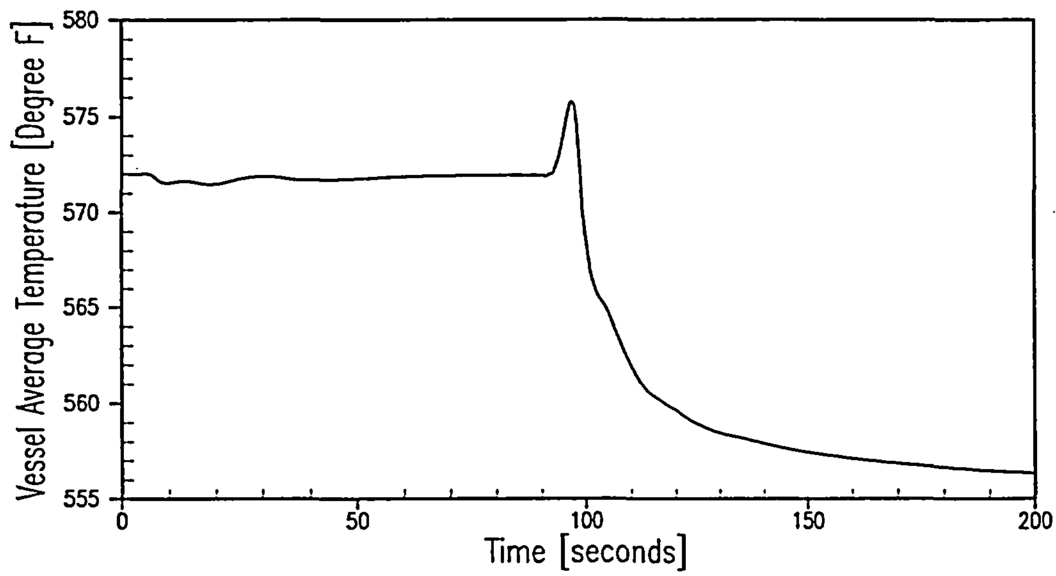
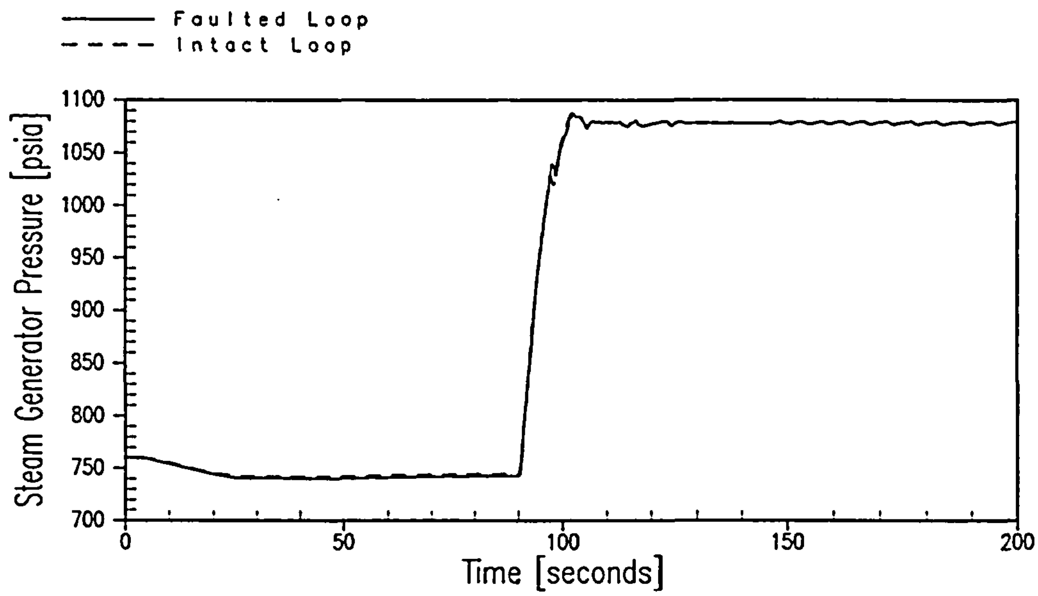


Figure 6.3-61

Feedwater System Malfunction at Full Power

(Loop Delta-T and Vessel Average Temperature vs. Time)



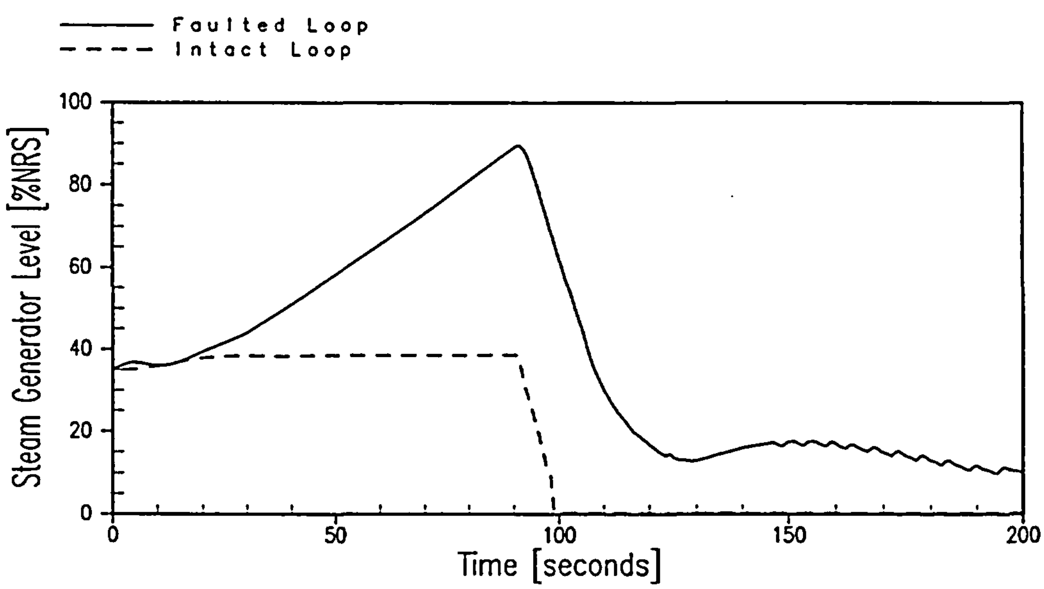
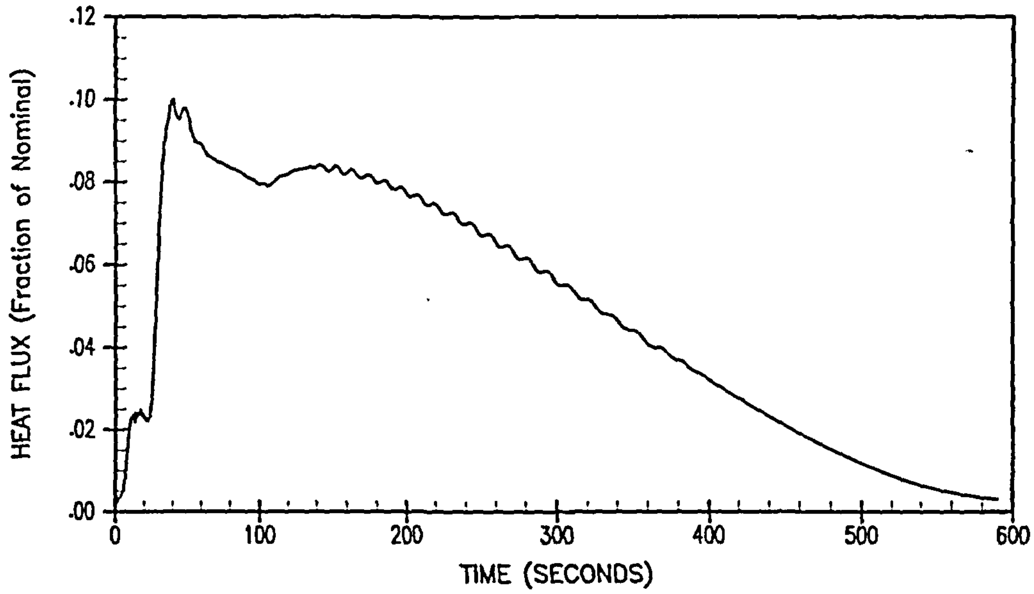


Figure 6.3-62

Feedwater System Malfunction at Full Power

(Steam Generator Pressure and Steam Generator Level vs. Time)



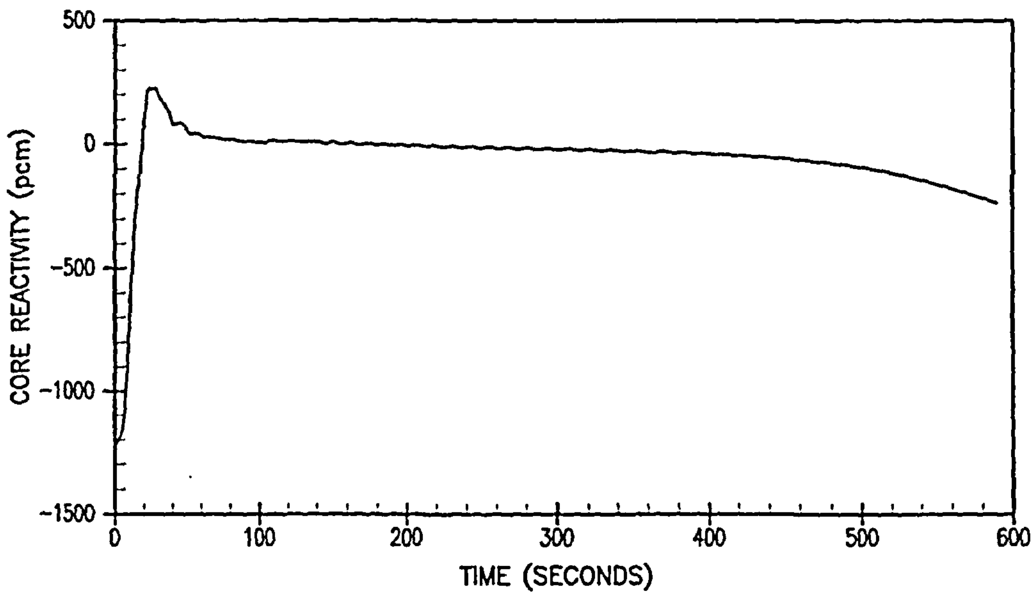


Figure 6.3-63

1.4 ft^2 Steamline Break, Offsite Power Available

(Core Heat Flux and Core Reactivity vs. Time)

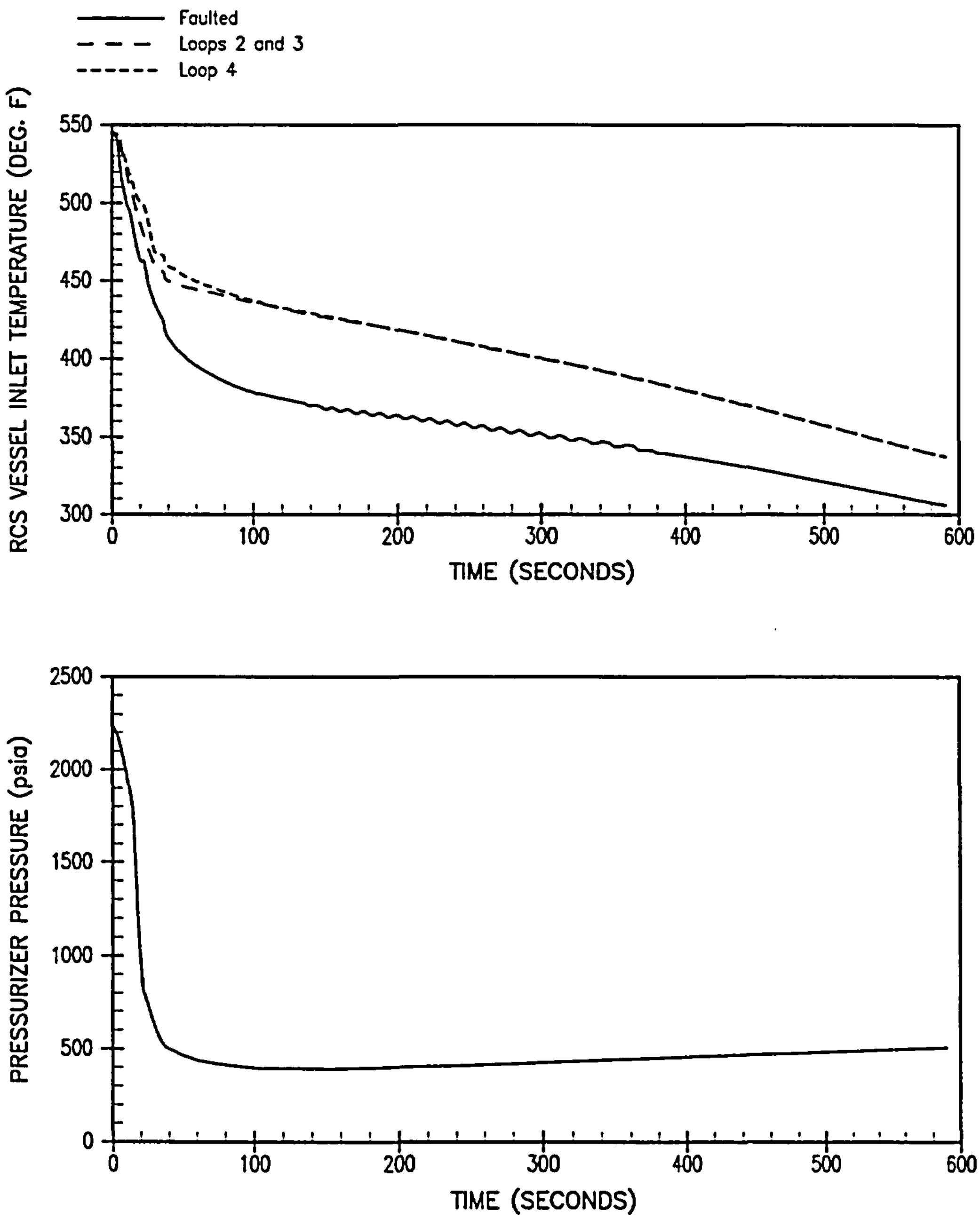
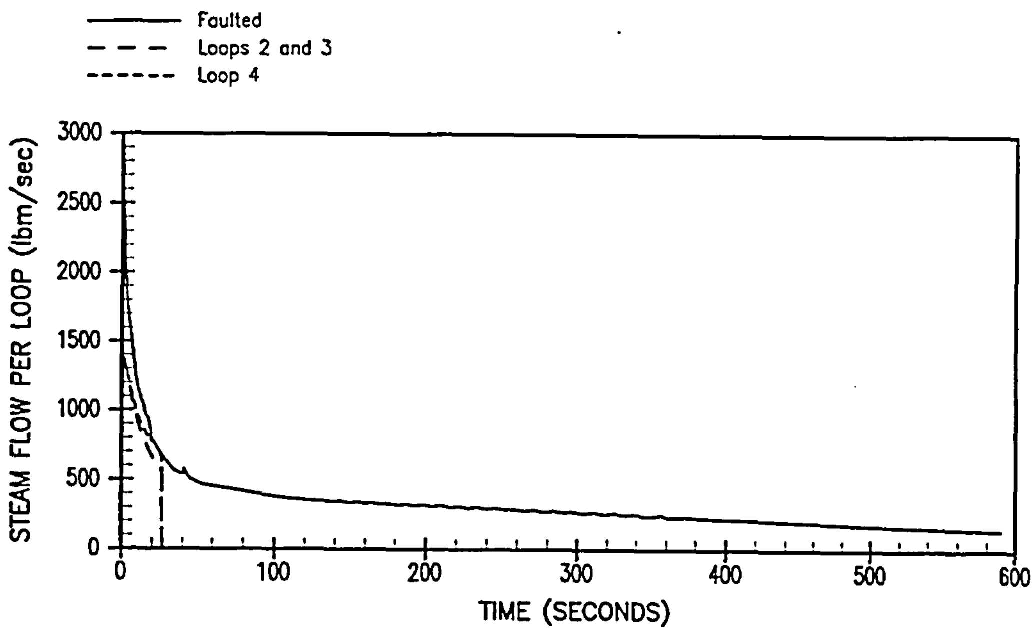


Figure 6.3-64

1.4 ft^2 Steamline Break, Offsite Power Available

(Reactor Vessel Inlet Temperature and Pressurizer Pressure vs. Time)



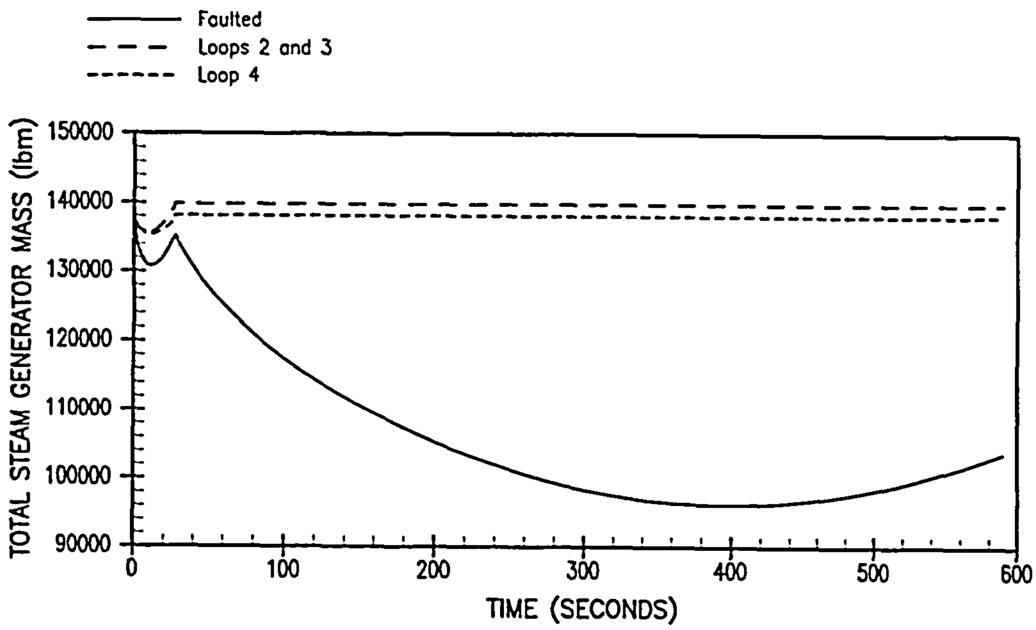


Figure 6.3-65

1.4 ft^2 Steamline Break, Offsite Power Available

(Steam Flow and Steam Generator Mass vs. Time)

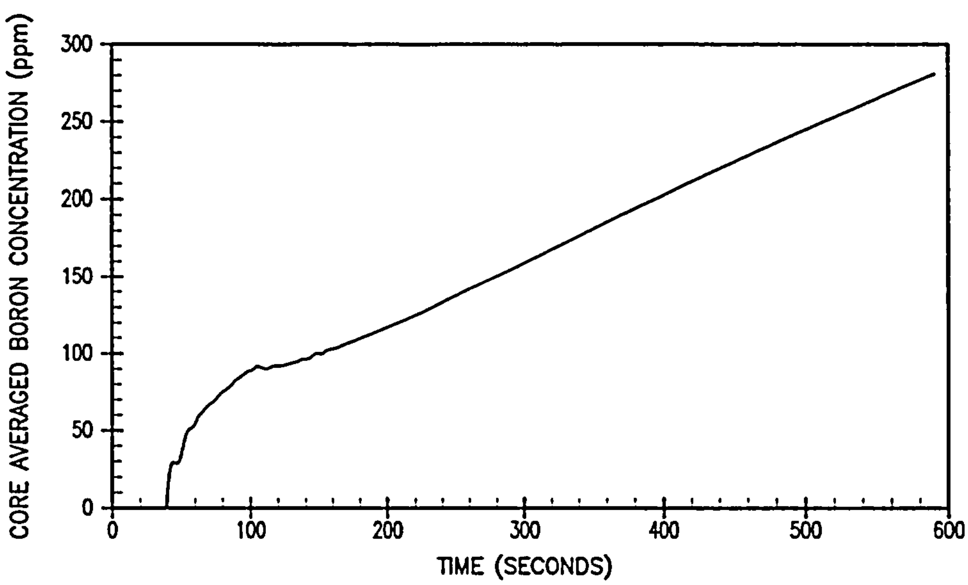
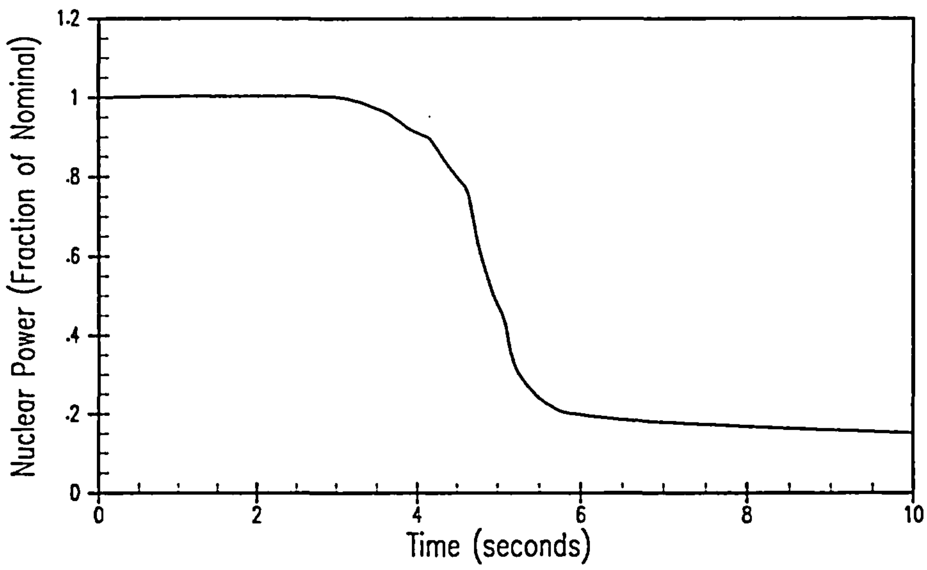


Figure 6.3-66

1.4 ft^2 Steamline Break, Offsite Power Available

(Core Averaged Boron Concentration vs. Time)



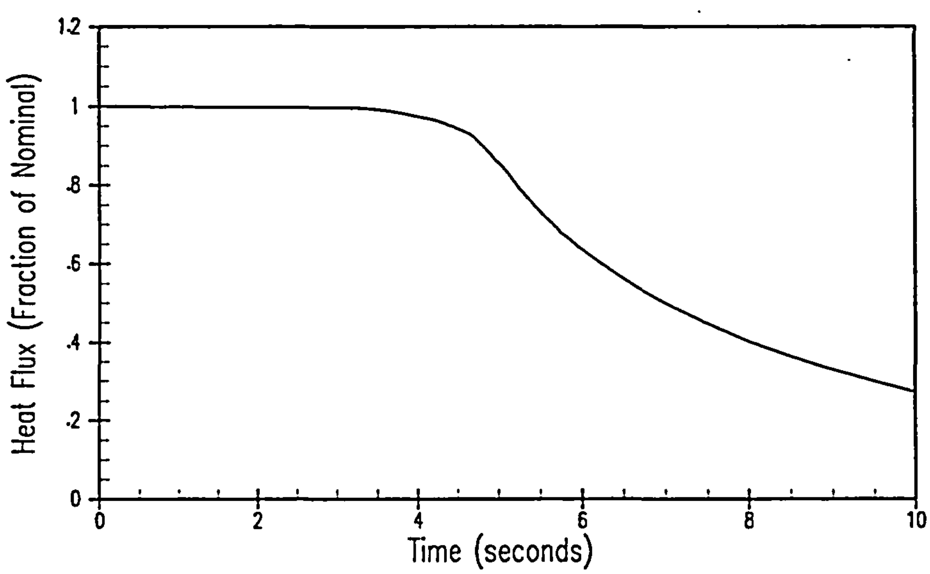


Figure 6.3-67

Partial Loss of Forced Reactor Coolant Flow

(Nuclear Power and Heat Flux vs. Time)

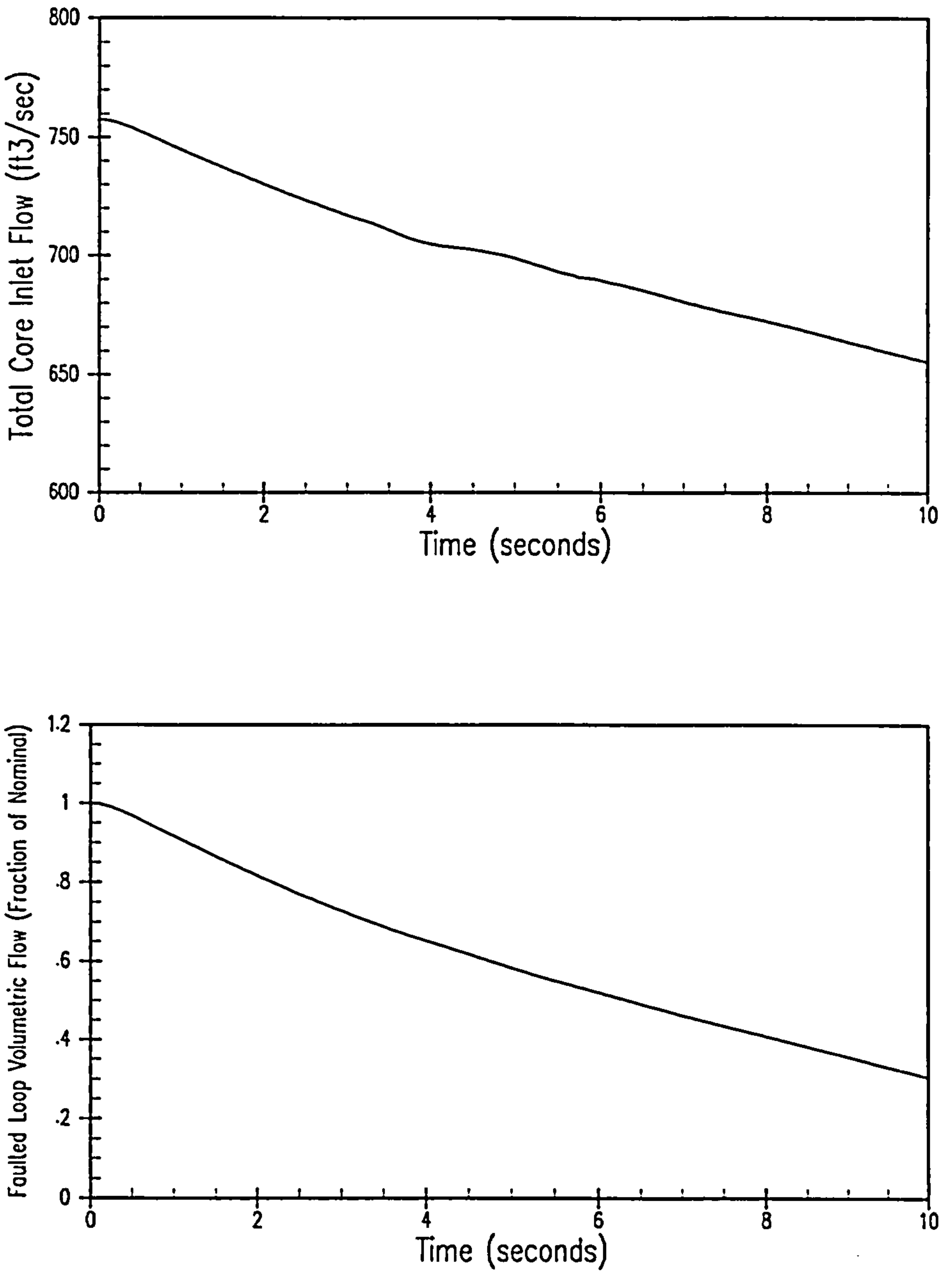
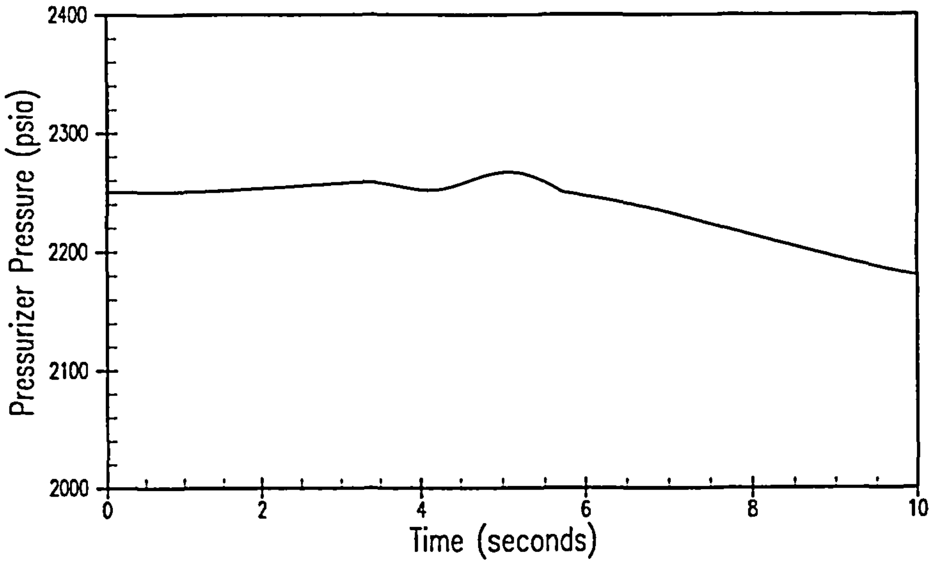


Figure 6.3-68

Partial Loss of Forced Reactor Coolant Flow

(Total Core Flow and Faulted Loop Flow vs. Time)



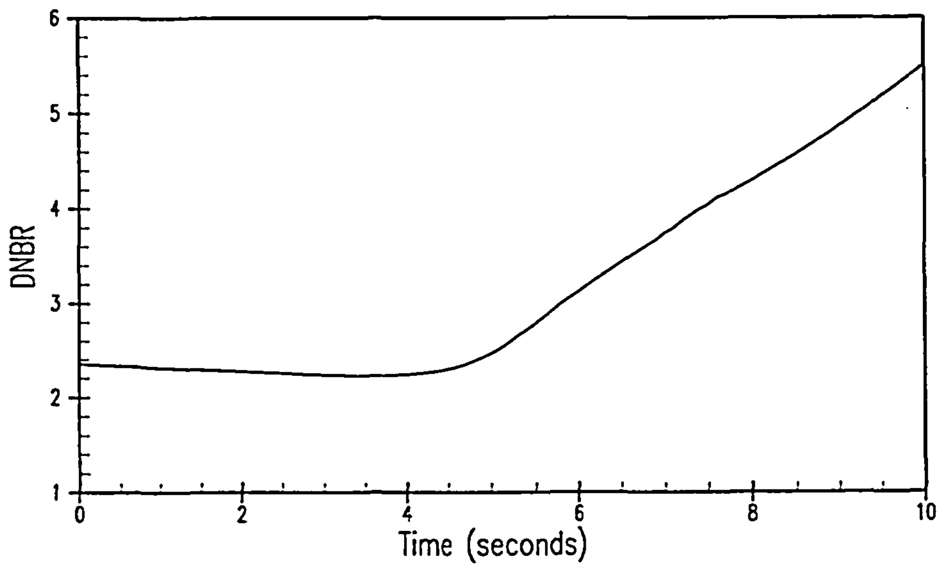


Figure 6.3-69

Partial Loss of Forced Reactor Coolant Flow

(Pressurizer Pressure and DNBR vs. Time)

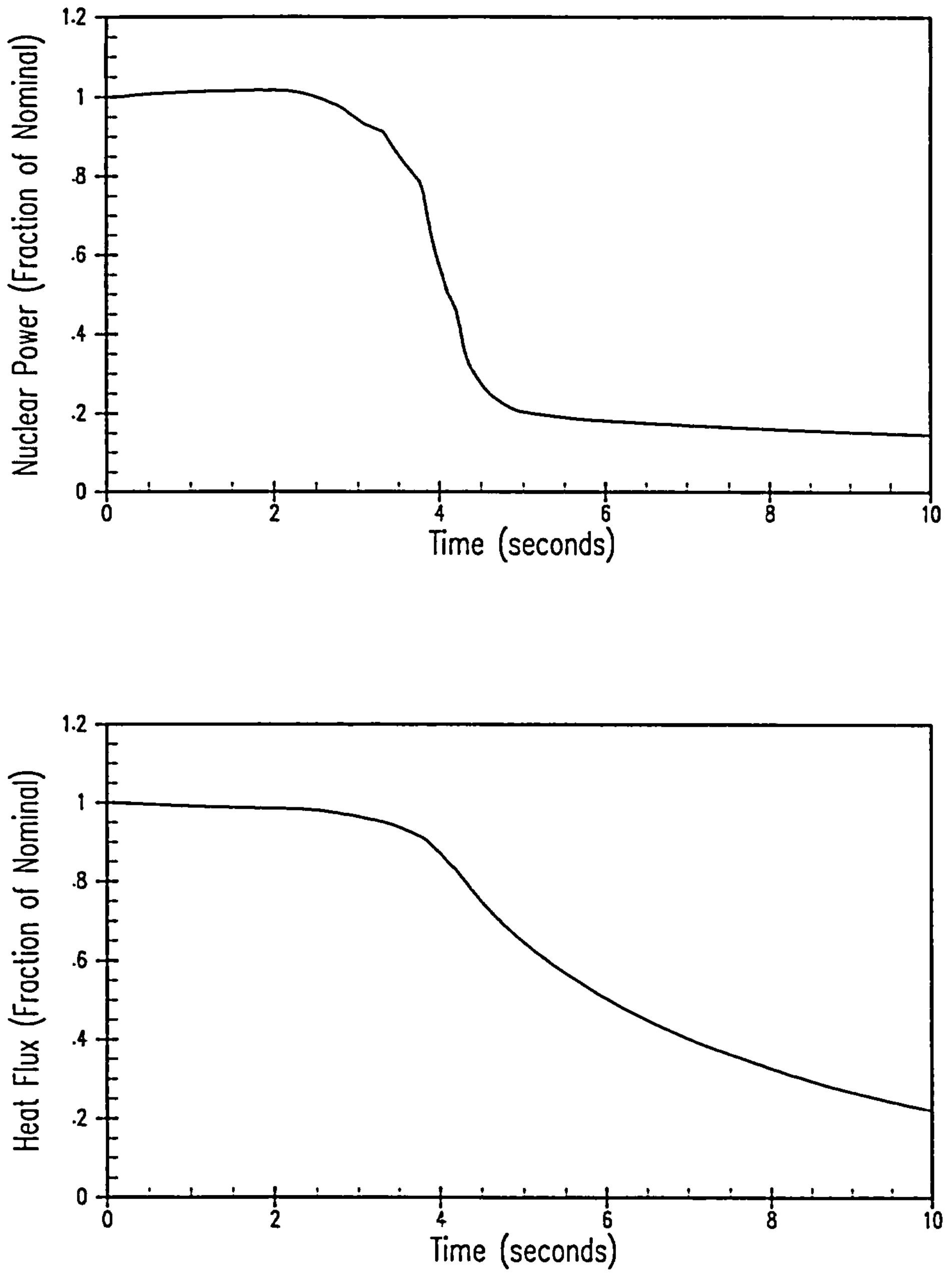
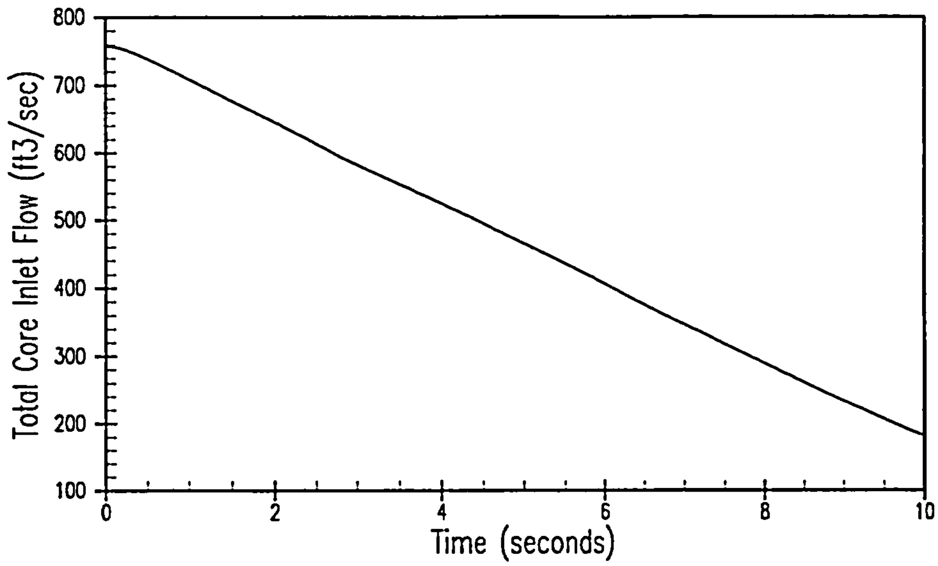


Figure 6.3-70

Complete Loss of Forced Reactor Coolant Flow – Frequency Decay

(Nuclear Power and Heat Flux vs. Time)



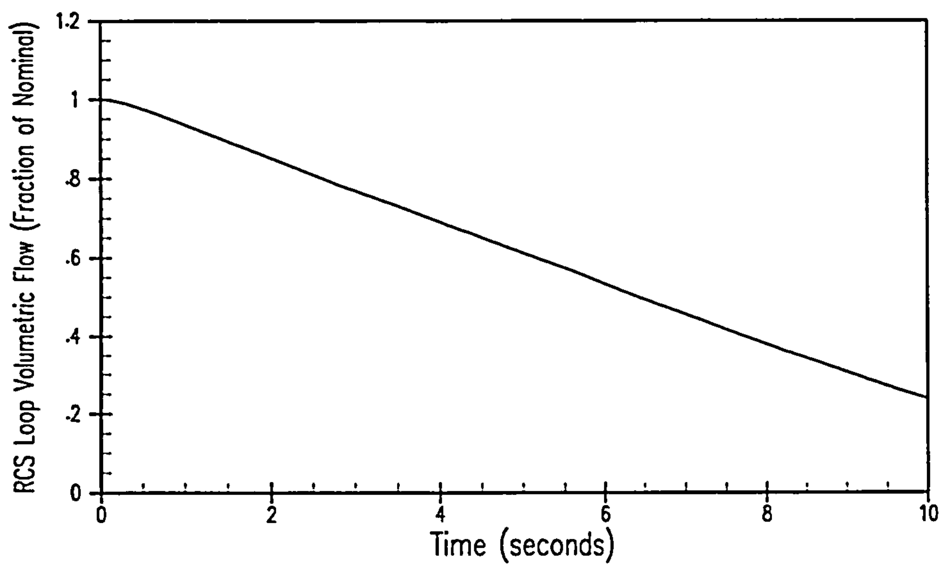


Figure 6.3-71

Complete Loss of Forced Reactor Coolant Flow – Frequency Decay

(Total Core Flow and RCS Loop Flow vs. Time)

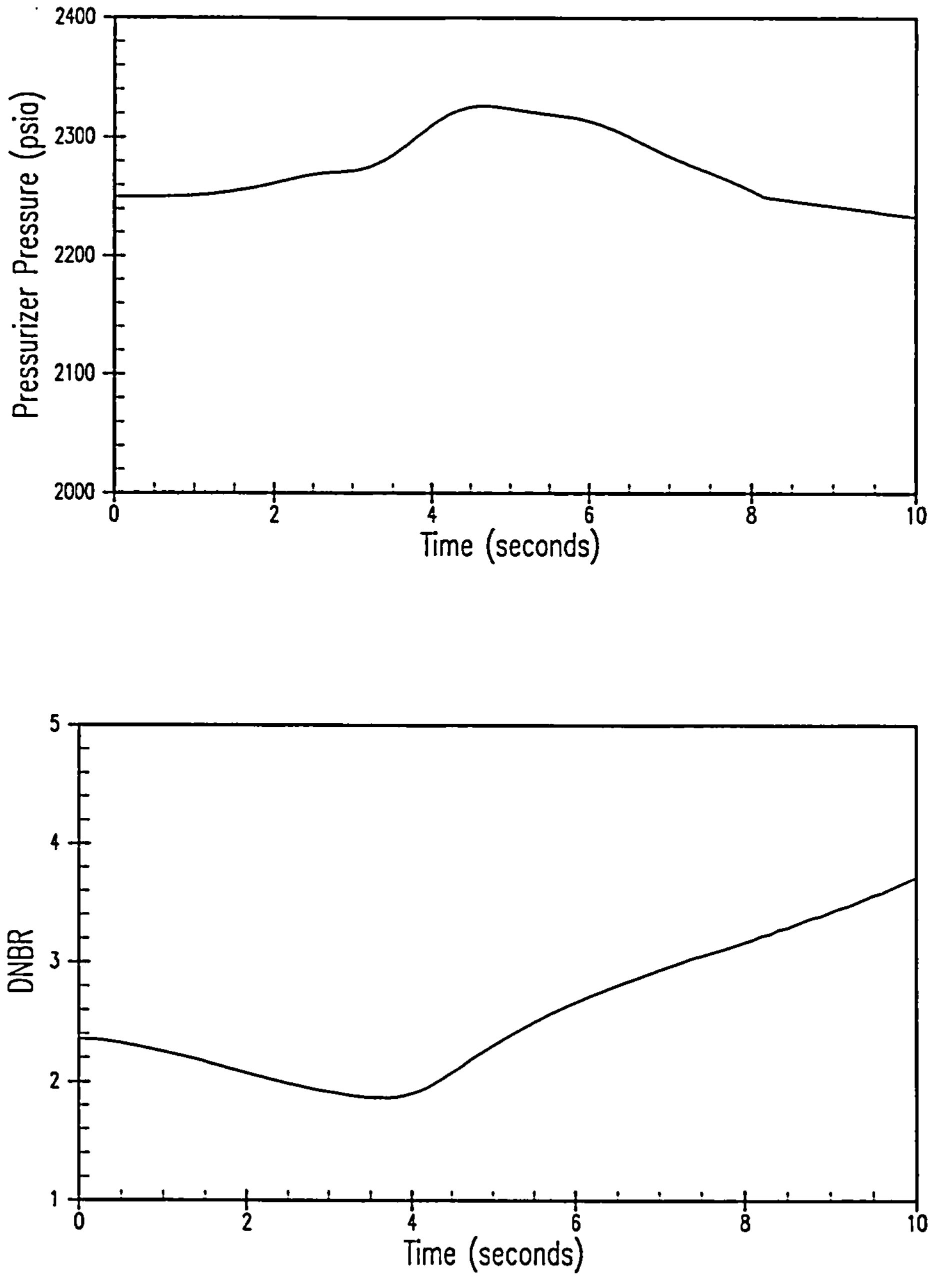


Figure 6.3-72

Complete Loss of Forced Reactor Coolant Flow – Frequency Decay

(Pressurizer Pressure and DNBR vs. Time)

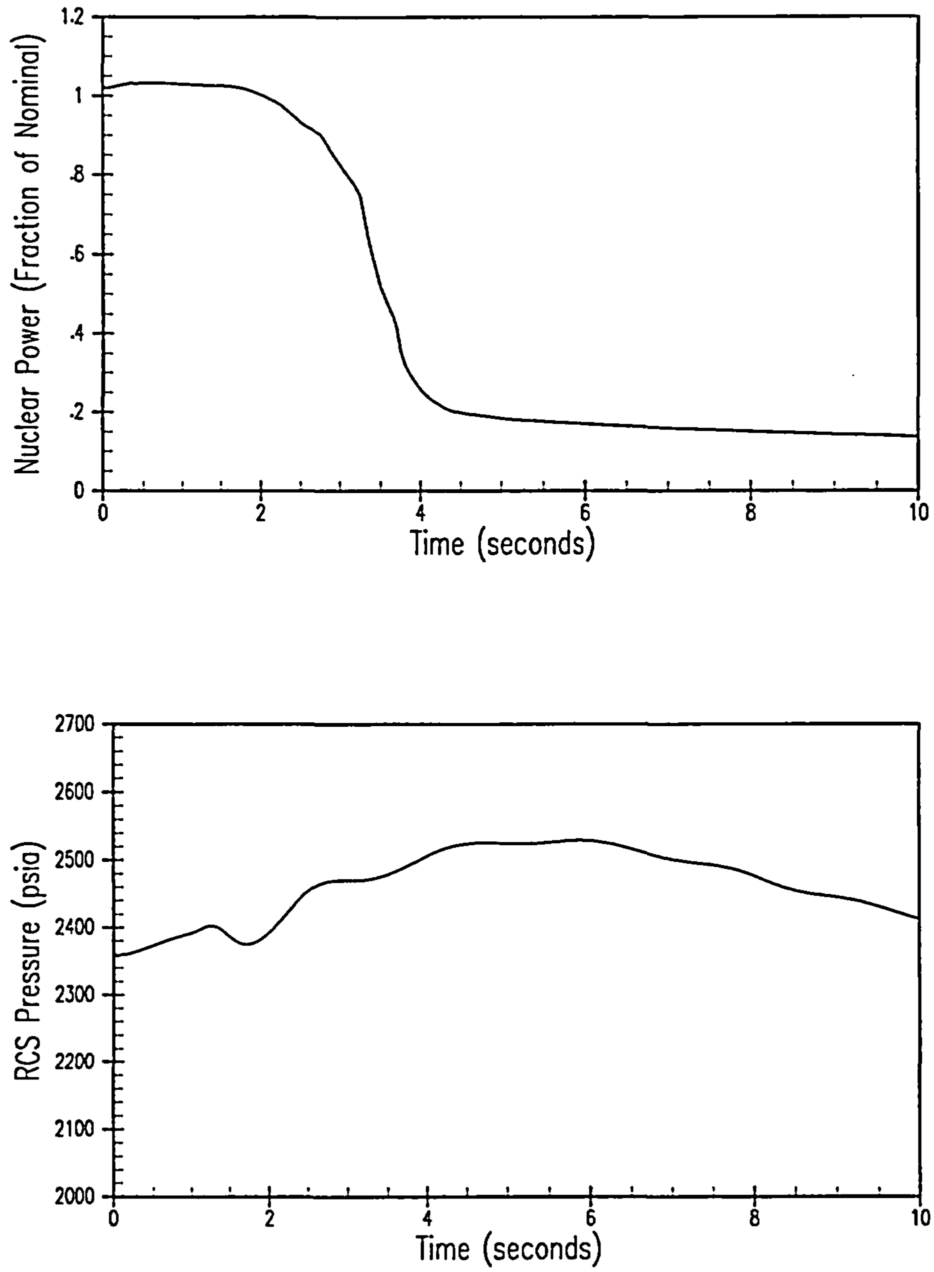


Figure 6.3-73

Locked Rotor/Shaft Break

(Nuclear Power and RCS Pressure vs. Time)

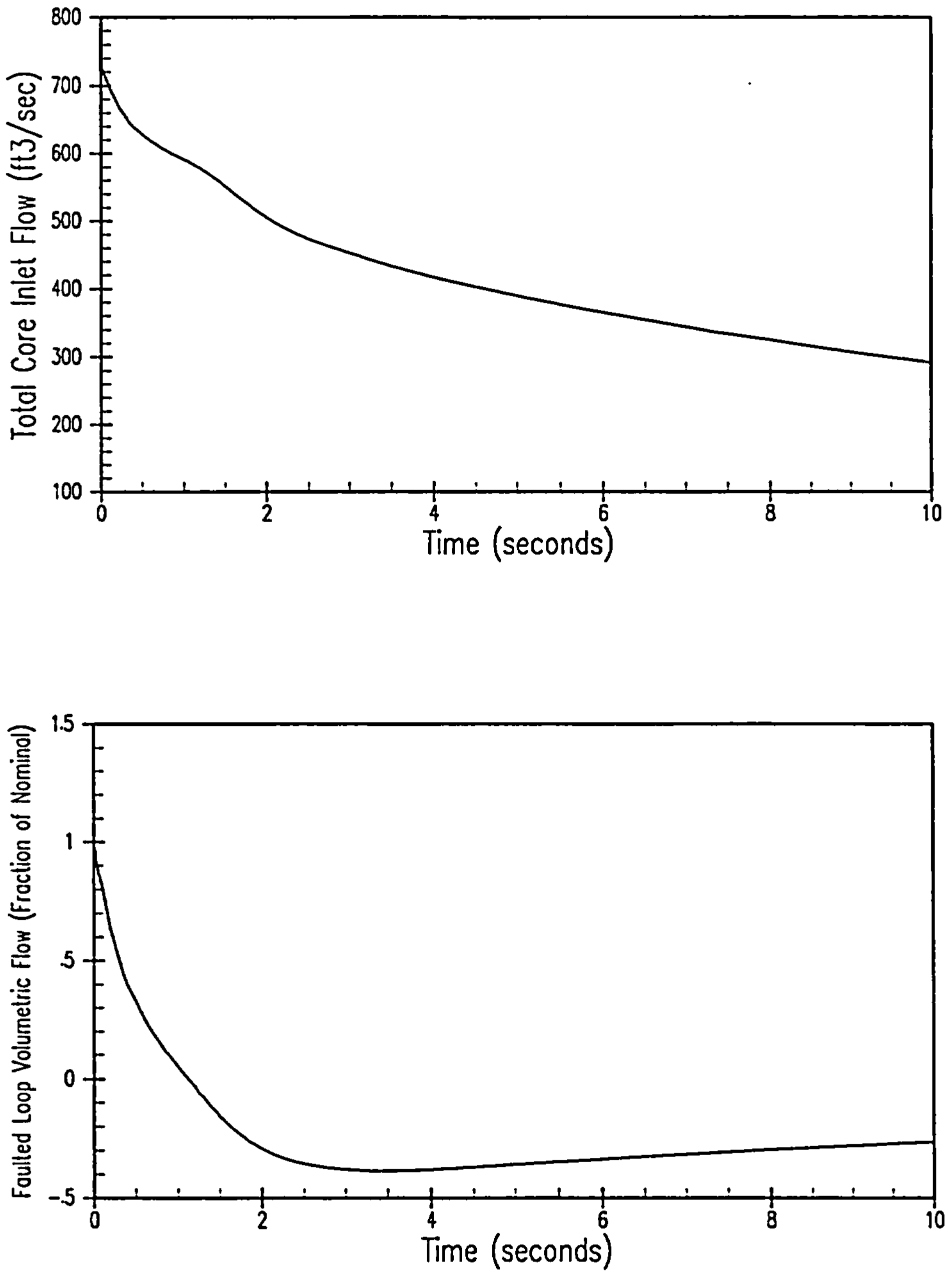


Figure 6.3-74

Locked Rotor/Shaft Break

(Total Core Flow and Faulted Loop Flow vs. Time)

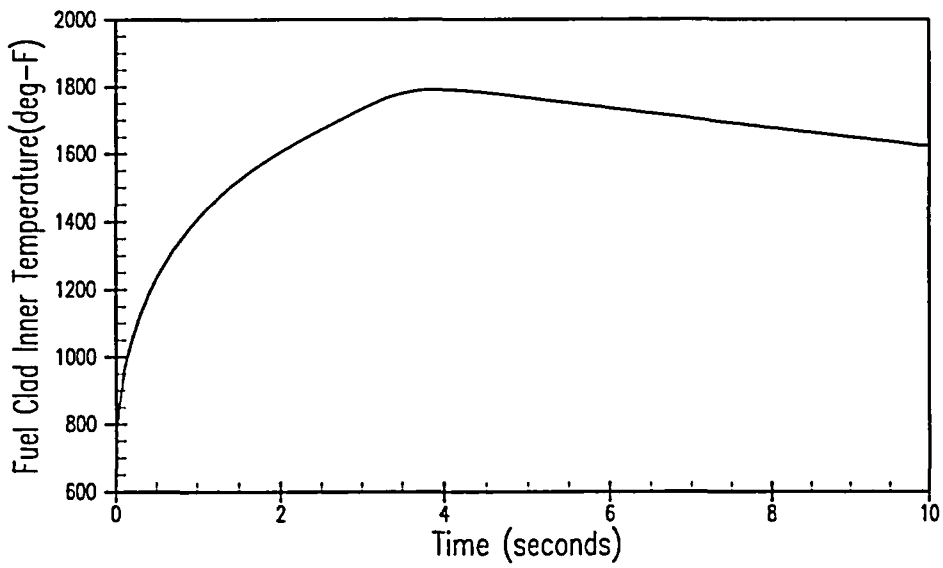


Figure 6.3-75
Locked Rotor/Shaft Break
(Fuel Clad Inner Temperature vs. Time)

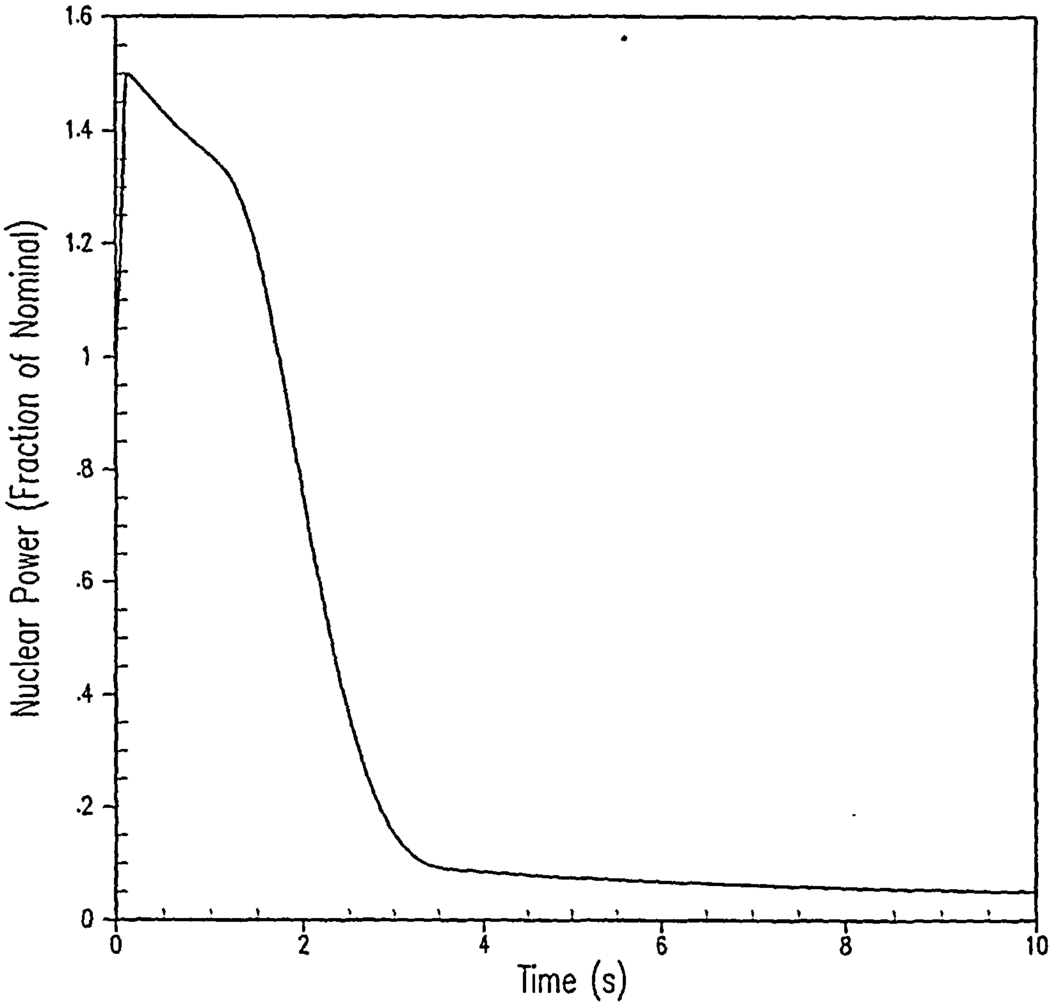


Figure 6.3-76

BOL HFP RCCA Ejection (Nuclear Power vs. Time)

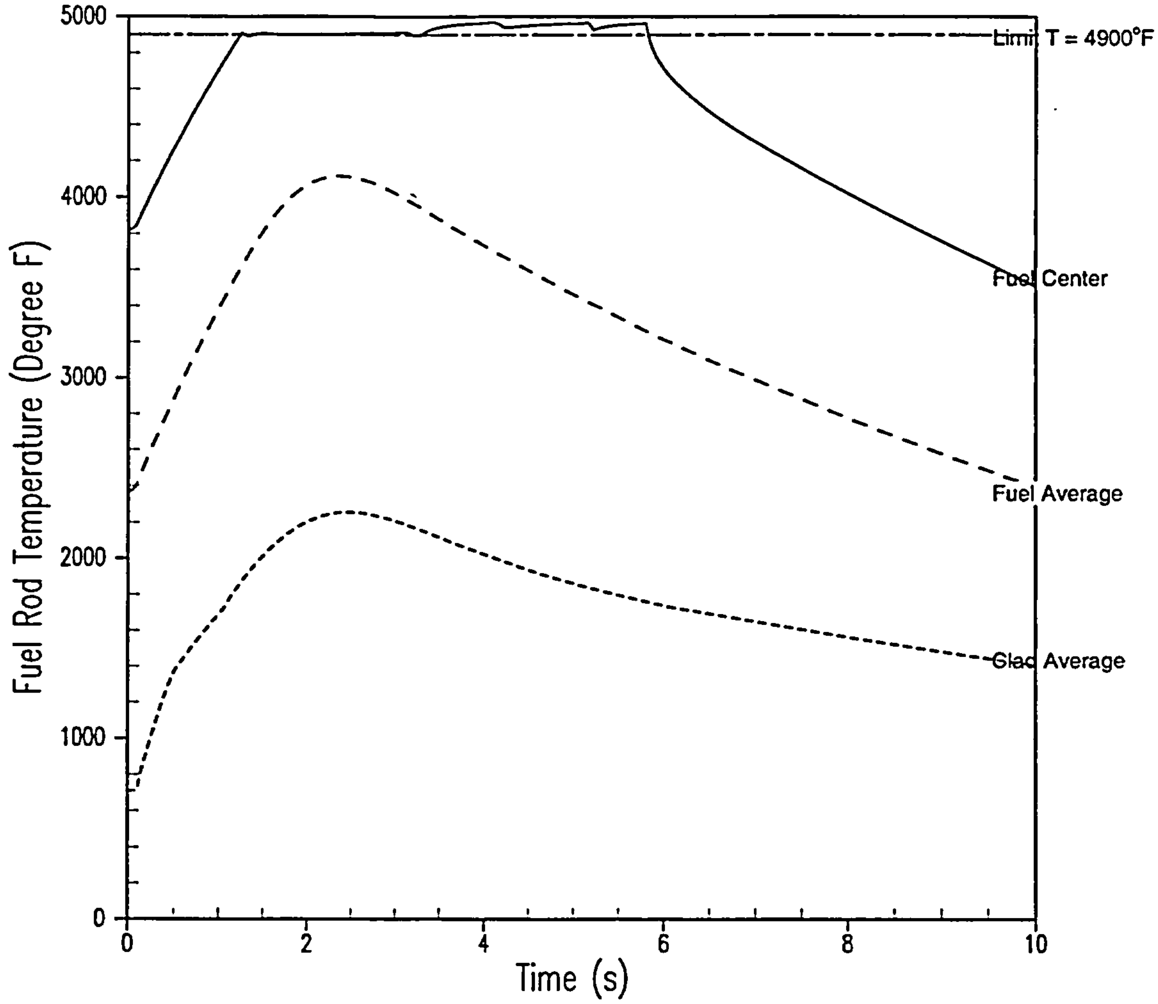


Figure 6.3-77

BOL HFP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

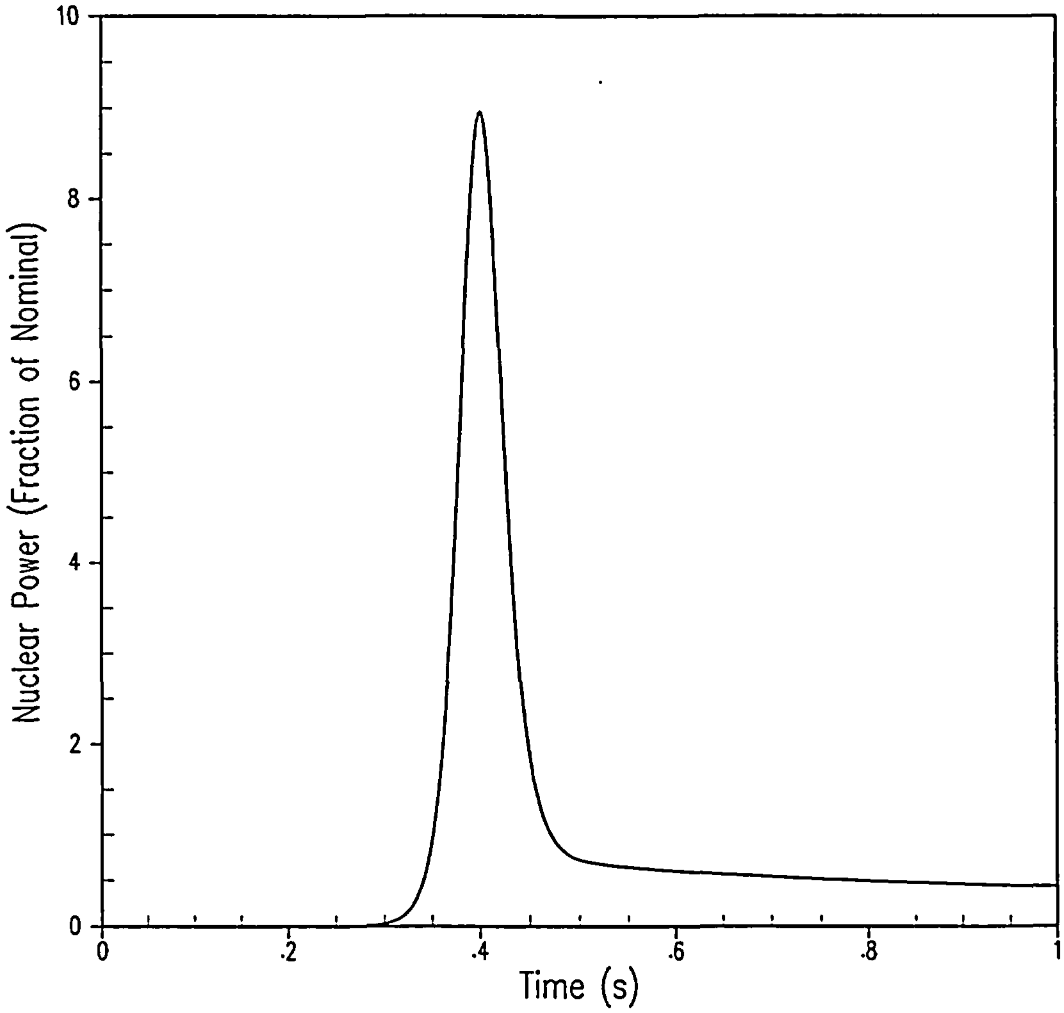


Figure 6.3-78
BOL HZP RCCA Ejection (Nuclear Power vs. Time)

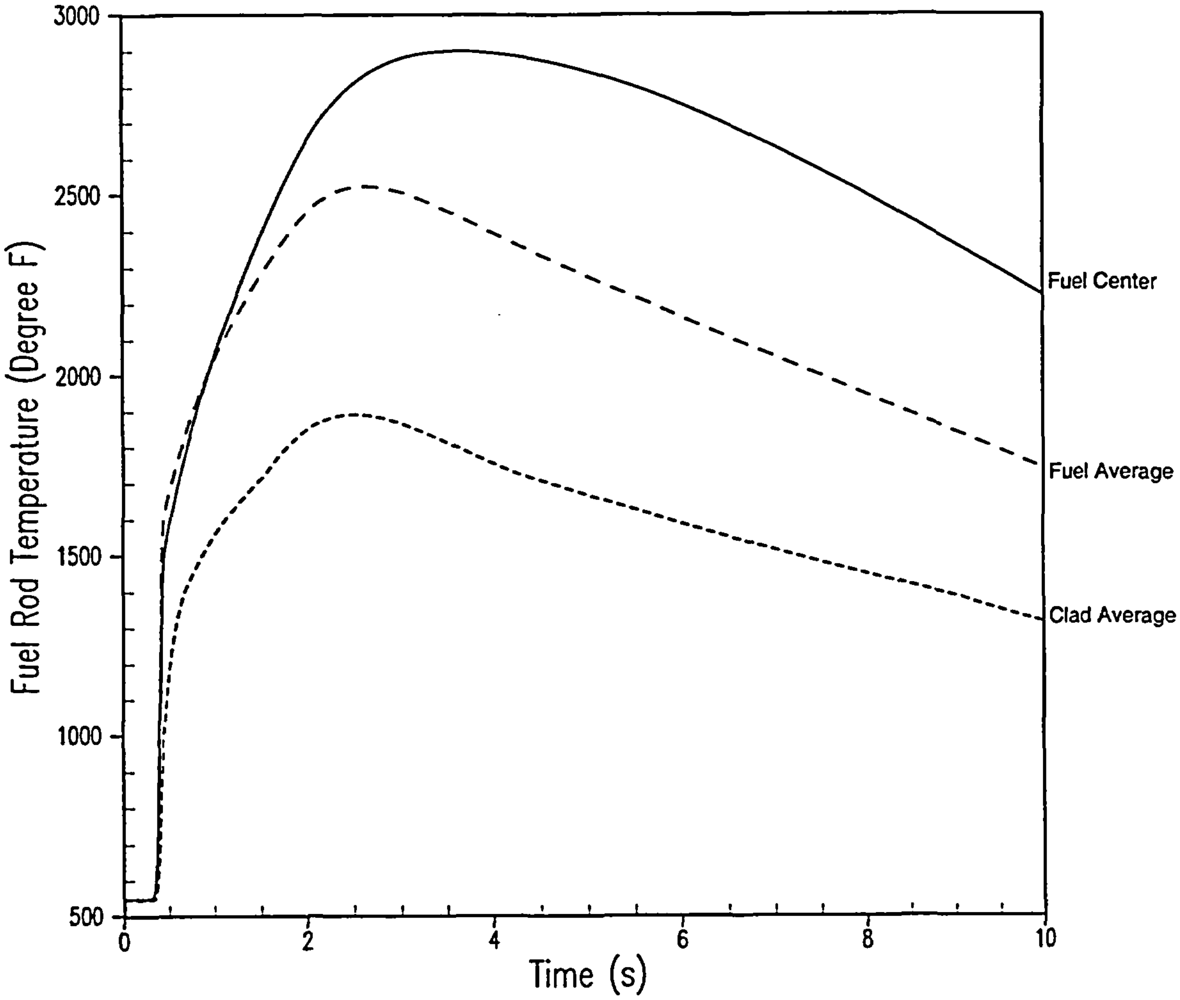


Figure 6.3-79

BOL HZP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

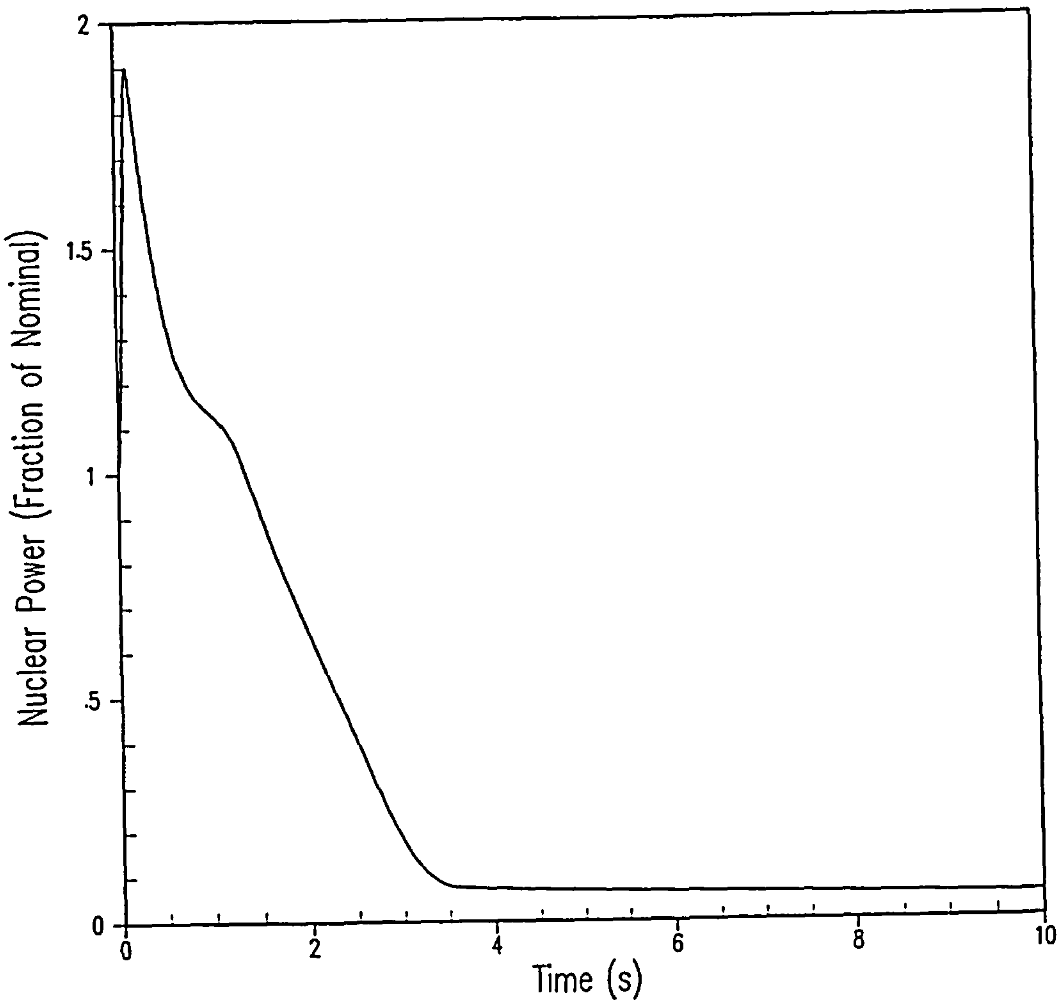


Figure 6.3-80
EOL HFP RCCA Ejection (Nuclear Power vs. Time)

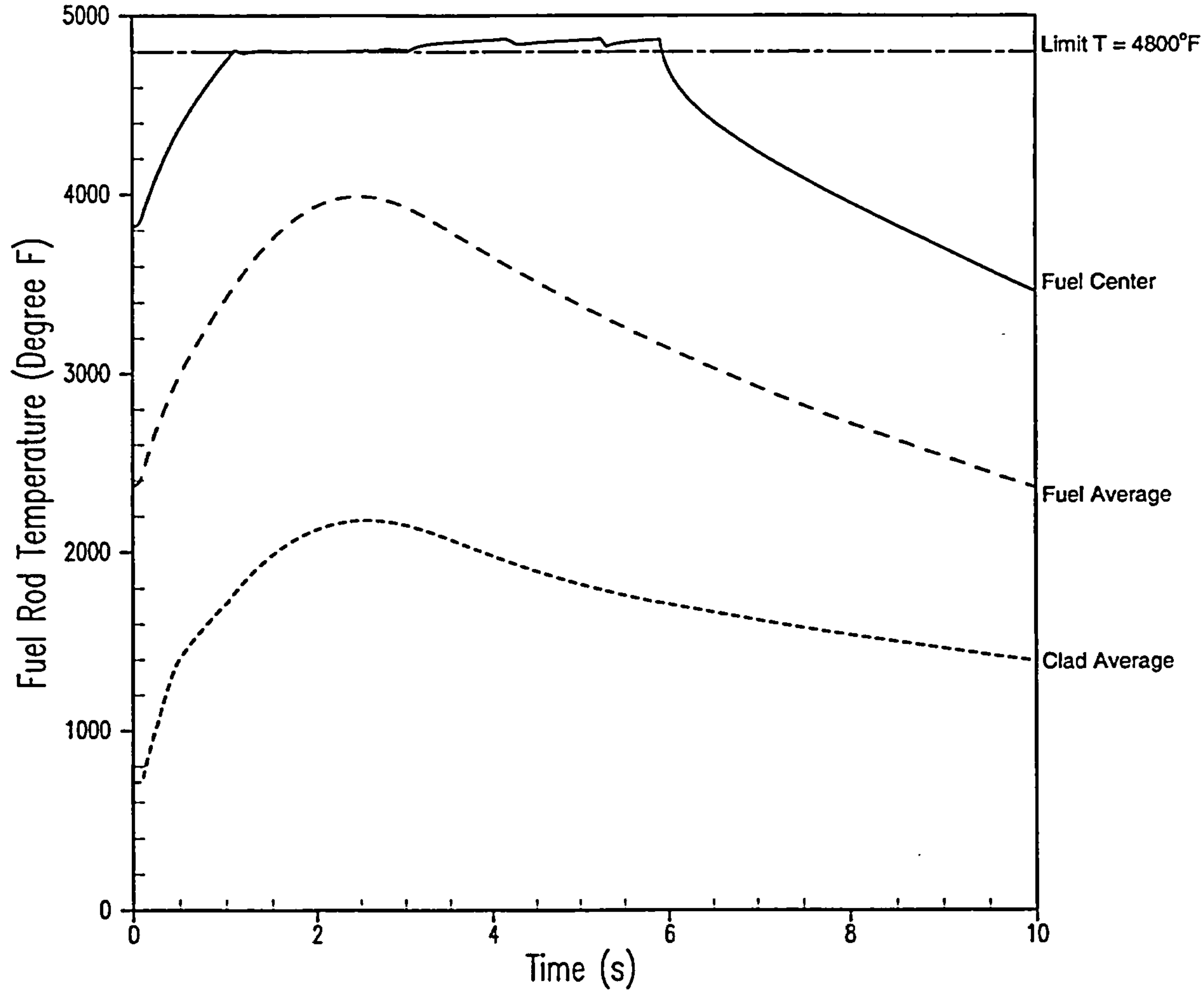


Figure 6.3-81

EOL HFP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

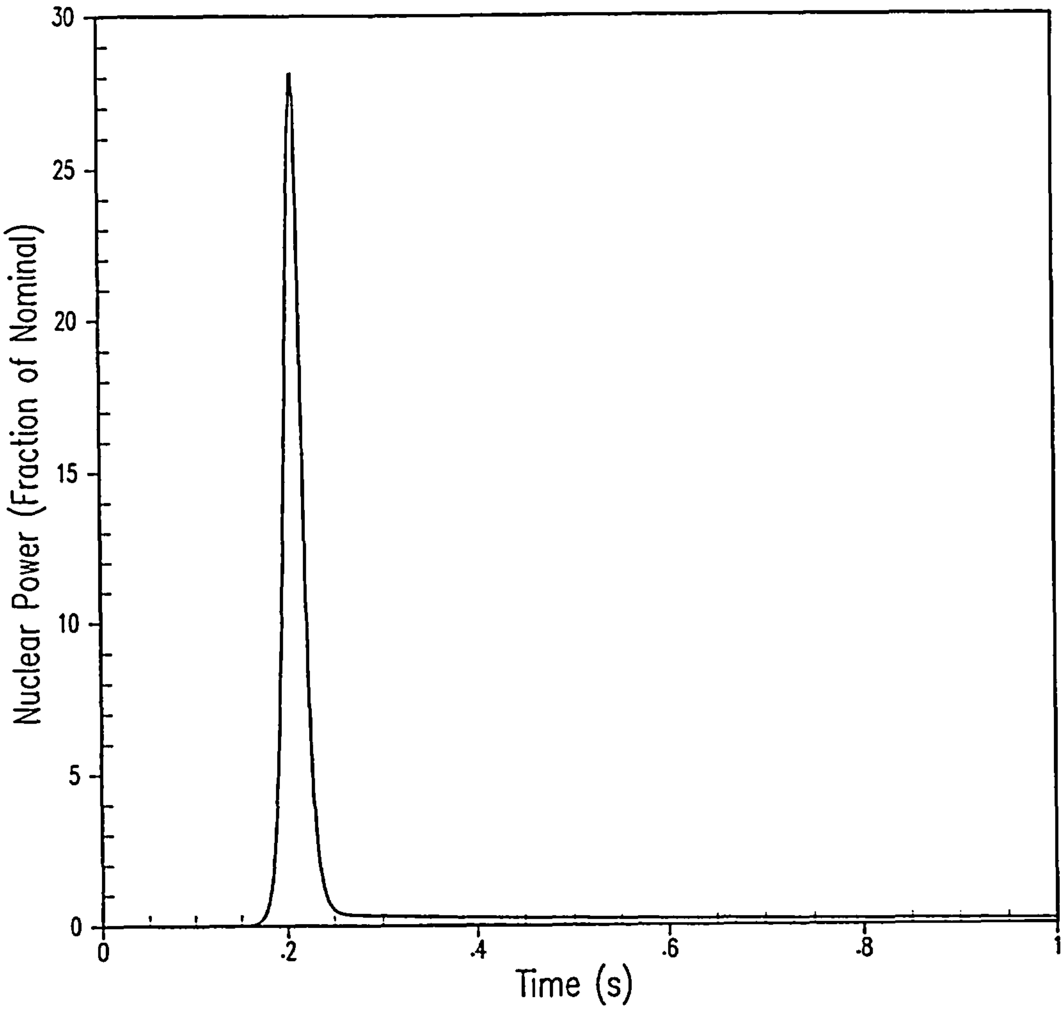


Figure 6.3-82

EOL HZP RCCA Ejection (Nuclear Power vs. Time)

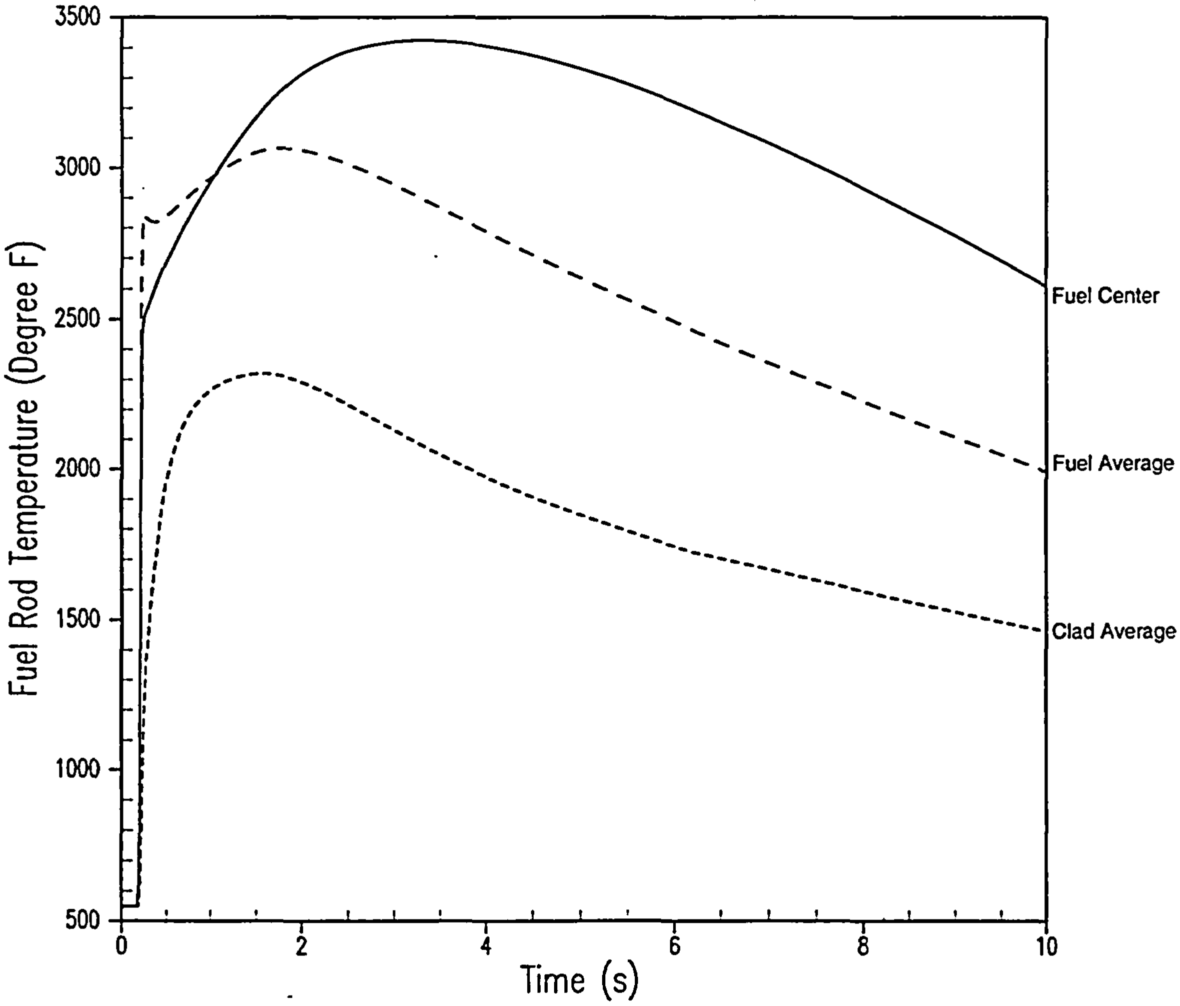


Figure 6.3-83

EOL HZP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)