FPL Energy
Seabrook Station

FPL Energy Seabrook Station
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MAR 17 2004

Docket No. 50-443
NYN-04016

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

Seabrook Station
Facility Operating License NPF-86
License Amendment Request 04-03,
Application for Stretch Power Uprate

References:

1. FPL Energy Seabrook, LLC letter NYN-03061, LAR 03-02 Alternate Source Term, dated October 6, 2003.

2. FPL Energy Seabrook, LLC letter NYN-04017, Proprietary Information to Support Seabrook Station LAR 04-03, dated March 17, 2004.

3. FPL Energy Seabrook, LLC letter NYN-02022, LAR 01-10, Relocation of Cycle Specific Parameters to the Core Operating Limits Report, dated April 15, 2002.

In accordance with the requirements of 10 CFR 50.90, FPL Energy Seabrook, LLC (FPL Energy Seabrook) requests amendments to the facility operating license, NPF-86, and the plant Technical Specifications for Seabrook Station. This Stretch Power Uprate (SPU) license amendment request (LAR) will increase the licensed reactor core power level by 5.2 percent from 3411 megawatts thermal (MWt) to 3587 MWt.

There is no specific review standard for the development of an SPU LAR. FPL Energy Seabrook developed this LAR utilizing the guidelines in NRC Review Standard, RS-001, "Review Standard for Extended Power Uprates." A cross-reference between the LAR and the matrices in RS-001 is provided in LAR Attachment 1, Tables 1.3-1 through 1.3-13.

The guidance of RS-001 states that SPUs are characterized by power level increases up to 7 percent and do not generally involve major plant modifications. Plant modifications are addressed in LAR Section 10.6 and are not considered to be major pursuant to the definition for a SPU. Since the requested uprate is 5.2 percent and does not involve major plant modifications, it is considered to be an SPU.

A001

The SPU LAR relies in part on two previous LARs submitted by FPL Energy Seabrook. The first LAR adopts the Alternate Source Term (AST) methodology for Seabrook Station. The second LAR relocates cycle specific boron parameters to the Core Operating Limits Report (COLR). The AST license amendment request, LAR 03-02, was submitted by FPL Energy Seabrook letter NYN-03061 (Reference 1). The COLR license amendment request, LAR 01-10, was submitted by FPL Energy Seabrook letter NYN-02022 (Reference 3). The SPU LAR assumes that LAR 03-02 and LAR 01-10 will be approved by the NRC and implemented at Seabrook Station prior to approval of the SPU LAR.

In addition, Westinghouse Electric Company has identified proprietary information that is not included in this LAR. The proprietary information, along with the required affidavit, is being submitted to the NRC by FPL Energy Seabrook letter NYN-04017 (Reference 2).

Several attachments to this letter support the Seabrook Station SPU. The attachments are summarized in the table below:

ATTACHMENT	DESCRIPTION
1	A technical assessment of the SPU including: description, background, system and component evaluations, design transients, nuclear fuel, accident analyses and environmental considerations.
2	Facility operating license, technical specifications, and technical specifications bases pages marked up to reflect the proposed changes.
3	Revised (clean copies) of the facility operating license, technical specifications, and technical specifications bases pages.
4	List of regulatory commitments associated with this LAR.
5	Schedule
6	No Significant Hazards Determination

As discussed in Attachment 1, Section 1.4, and Attachment 6 to this letter, the proposed amendment does not involve a significant hazards consideration pursuant to 10 CFR 50.92. A copy of this letter and the enclosed LAR have been forwarded to the New Hampshire State Liaison Officer pursuant to 10 CFR 50.91(b).

FPL Energy Seabrook requests approval of this proposed amendment by December 31, 2004. Approval by December 31, 2004 will support the refueling outage currently scheduled to begin in April 2005 and allows FPL Energy Seabrook to take advantage of the economic benefits of the SPU as soon as possible. The requested approval date is consistent with the NRC review schedule for SPUs. In addition, FPL Energy Seabrook requests 12 months to implement the LAR.

FPL Energy Seabrook has determined that the information for the proposed amendment does not involve a significant hazards consideration, authorize a significant change in the types or total amounts of effluent release, or result in any significant increase in individual or cumulative

occupational radiation exposure. Therefore, the proposed amendment meets the categorical exclusion requirements of 10 CFR 51.22(c)(9) and an environmental impact appraisal need not be prepared.

The Station Operation Review Committee and the Company Nuclear Review Board have reviewed LAR 04-03.

Should you have any questions concerning this LAR, please contact Mr. Stephen T. Hale, Power Uprate Project Manager, at (603) 773-7561.

Very truly yours,

FPL Energy Seabrook, LLC

Mark E. Warner
Site Vice President

Attachments (6)

cc: H. J. Miller, NRC Region I Administrator
V. Nerses, NRC Project Manager, Project Directorate I-2
G. T. Dentel, NRC Resident Inspector

Mr. Bruce Cheney, Director
New Hampshire Bureau of Emergency Management
State Office Park South
107 Pleasant Street
Concord, NH 03301-3809

Oath and Affirmation

I, Mark E. Warner, Site Vice President of FPL Energy Seabrook, LLC hereby affirm that the information and statements contained within this license amendment request are based on facts and circumstances which are true and accurate to the best of my knowledge and belief.

Sworn and Subscribed
Before me this

17 day of March, 2004

Notary Public

Mark E. Warner
Site Vice President

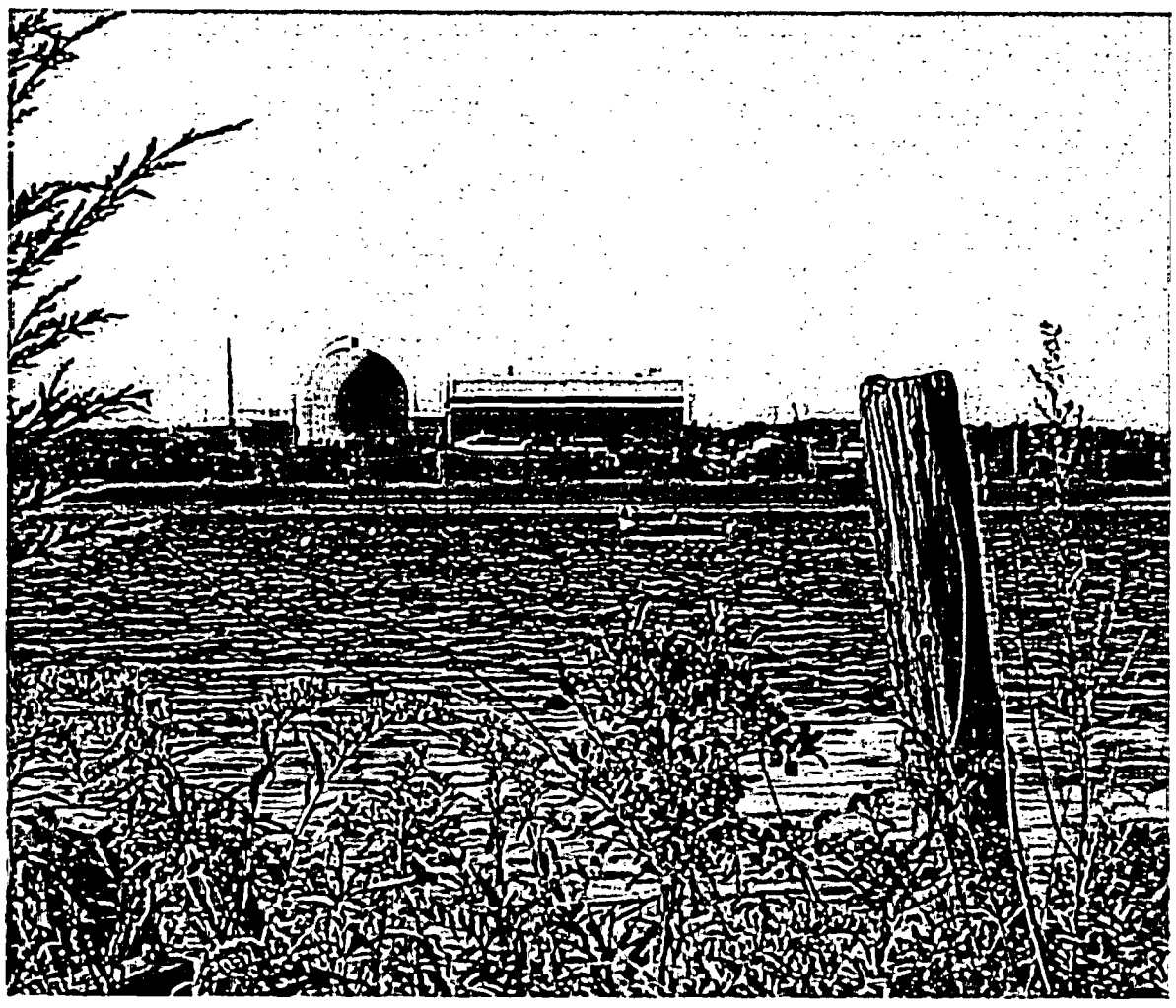
MICHAEL D. O'KEEFFE
MY COMMISSION EXPIRES FEB. 5, 2008
NOTARY PUBLIC
NEW HAMPSHIRE

Attachments 1 – 6

Power Uprate License Amendment Request

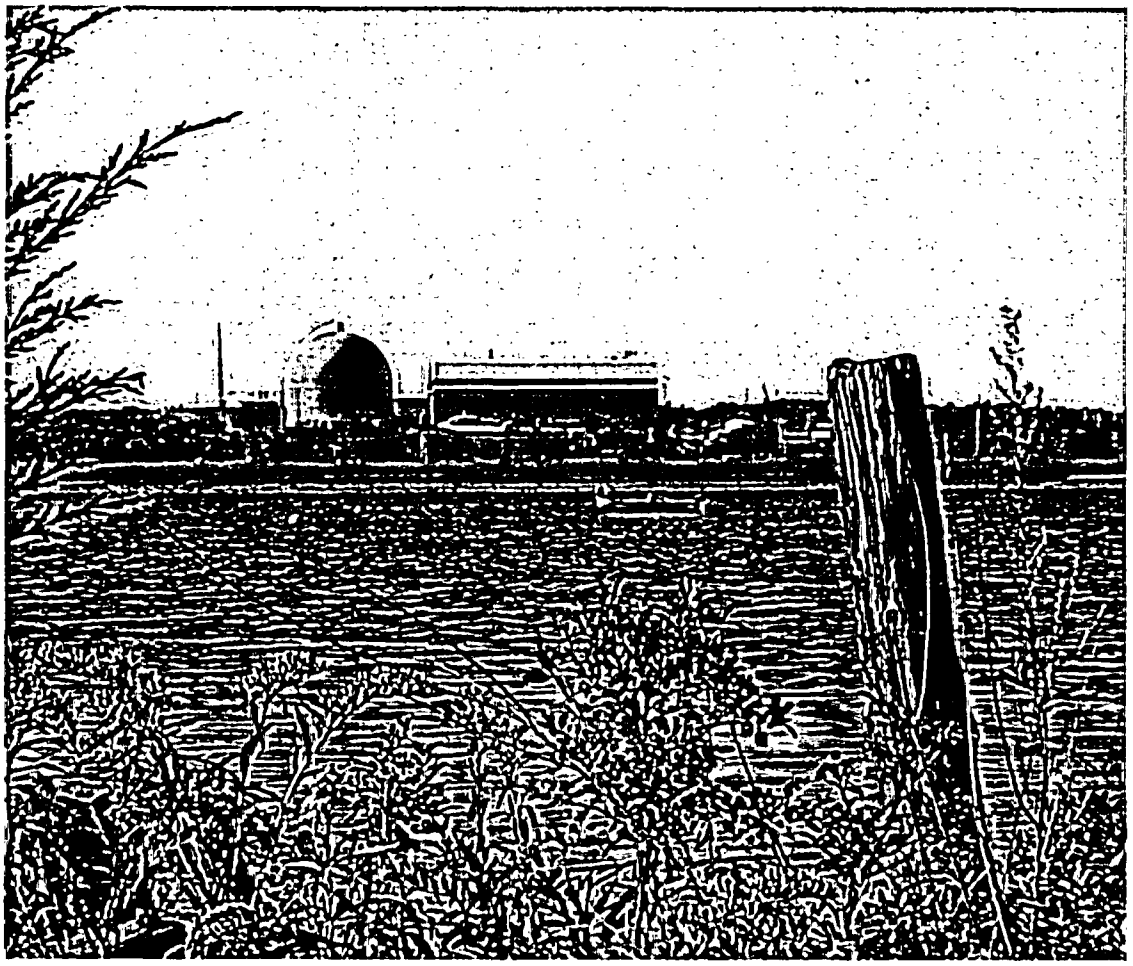
FPL Energy
Seabrook Station

Stretch Power Uprate License Amendment Request



Stretch Power Uprate
License Amendment Request

SEABROOK STATION



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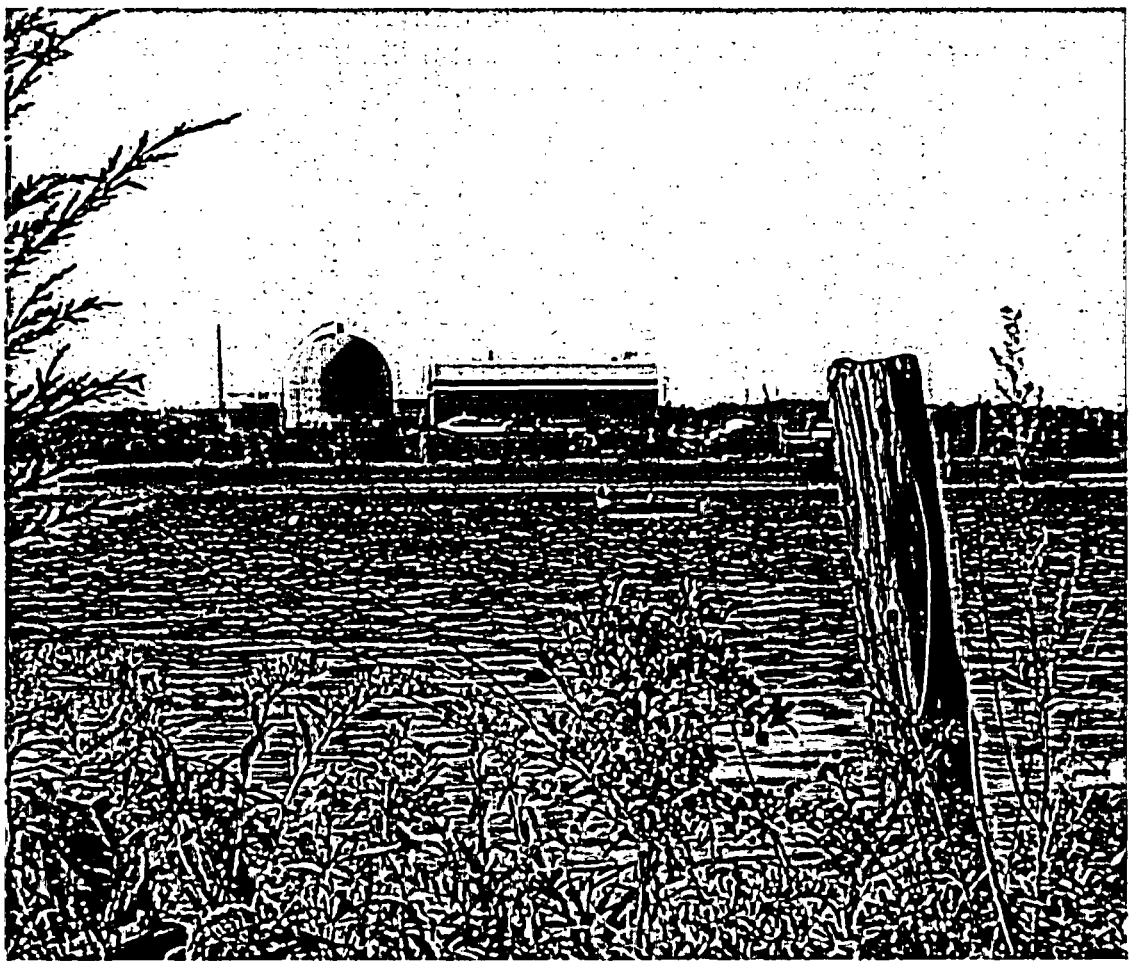
Stretch Power Uprate License Amendment Request

SEABROOK STATION



ATTACHMENT 1

TECHNICAL ASSESSMENT, REGULATORY ANALYSIS, AND ENVIRONMENTAL EVALUATION

SEABROOK STATION

SECTION 1.0

INTRODUCTION

ATTACHMENT 1
TECHNICAL ASSESSMENT, REGULATORY ANALYSIS, AND ENVIRONMENTAL EVALUATION

1.0 INTRODUCTION

Like most nuclear units, the Seabrook Station was originally designed with equipment and systems capable of accommodating operating conditions above the original licensed power rating including higher pressures, flows and temperatures. In addition, continuing improvements in the analytical techniques, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the difference between the calculated safety analyses results and the licensing limits. These available safety margins, combined with the excess margin in the as-designed equipment, system and component capabilities, provide the Seabrook Station with the potential to increase its thermal power rating by less than 6%. The 5.2% proposed increase was selected because it can be accomplished without major Nuclear Steam Supply System (NSSS) or Balance of Plant (BOP) hardware modifications, and with no significant increase in the hazards presented by the plant as approved by the Nuclear Regulatory Commission in the original Facility Operating License.

FPL Energy Seabrook proposes to amend the Seabrook Station Facility Operating License, NPF-86, and the Technical Specifications to increase the licensed thermal power. Seabrook Station is currently licensed to operate at a maximum reactor core power level of 3411 megawatts thermal (MWt). FPL Energy Seabrook is requesting that the licensed reactor core power level be increased by 5.2 percent to 3587 MWt. No major modifications to the plant are required for this uprate. The specific high pressure turbine steam path modifications addressed in this license amendment request (LAR), were chosen with consideration to cost benefit and optimization of thermal efficiency. Other secondary side modifications are not required for the uprate, but are listed in LAR Subsection 10.6.2 for completeness.

There is no regulatory guidance for the development of a stretch power uprate (SPU) LAR. FPL Energy Seabrook developed this LAR with the guidelines in Nuclear Regulatory Commission Review Standard, RS-001, "Review Standard for Extended Power Uprates" [Reference 1.3-1]. The LAR expectations of RS-001 extend beyond those historically required for an SPU . The guidance of RS-001 supports the characterization of the Seabrook Station power uprate as a stretch power uprate. A cross-reference between the LAR and the matrices in RS-001 is provided in LAR Tables 1.3-1 through 1.3-13.

1.1 PURPOSE AND SCOPE

The purpose of performing the Seabrook Station NSSS and BOP analyses and evaluations is to demonstrate that the NSSS and BOP will remain in compliance with applicable licensing criteria and requirements and can operate acceptably at the increased thermal/electrical power conditions. This report summarizes the analyses and evaluations and their results.

FPL Energy Seabrook has evaluated the impact of the SPU from a licensed core power of 3411 MWt to 3587 MWt for the applicable systems, structures, components, and safety analyses at Seabrook Station assuming a conservative core power level of 3659 MWt (2% greater than 3587 MWt). The SPU scope included the reanalysis and/or evaluation of each Seabrook Station UFSAR Chapter 15 accident analyses. The SPU scope also included evaluation of major NSSS components (e.g., reactor pressure vessel, pressurizer, reactor coolant pumps, and steam generators), BOP components, (e.g., turbine generator, and condensate and feedwater pumps), and major systems and sub-systems (e.g., safety injection, emergency feedwater, residual heat removal, electrical distribution, emergency diesel generators, and containment systems). Control systems (e.g., rod control, pressurizer pressure and level, turbine overspeed, steam generator level, and atmospheric steam dump) have been evaluated for operation at the SPU conditions.

Reactor trip and engineered safety features actuation setpoints have been assured for the SPU conditions. The results of the analyses and evaluations have yielded acceptable results and demonstrate that all design basis acceptance criteria will continue to be satisfied during the SPU conditions. These evaluations are contained in LAR Section 4.0.

With regard to radiological consequences, this SPU LAR relies on a separate LAR 03-02 submitted to the Nuclear Regulatory Commission by FPL Energy Seabrook letter NYN-03061, dated October 6, 2003 [Reference 1.1-1], to adopt Alternate Source Term methodology for Seabrook Station. Note that the analyses and evaluations for the Alternate Source Term LAR were also performed at a core power level of 3659 MWt. Approval of the Alternate Source Term LAR is required to support this SPU LAR.

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

- Westinghouse Electric Company
- Stone & Webster, Inc. (Shaw)
- General Electric Energy Services
- FPL Energy Seabrook

The scope of each of these organizations is as follows:

Westinghouse Electric Company

Westinghouse analyses and evaluations included the NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel. The results of the Westinghouse NSSS analyses and evaluations satisfy the project purpose and demonstrate that applicable licensing criteria and requirements are satisfied for the NSSS performance parameters, design transients, systems, components, accidents and nuclear fuel at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The SPU analyses and evaluations in this LAR were based on the parameters presented in LAR Section 2.0.

Stone & Webster, Inc. (Shaw)

Stone & Webster analyses and evaluations were performed at an analyzed core power level of 3659 MWt (3678 MWt NSSS power level). These analyses and evaluations included the BOP systems and components, containment response to LOCA and Non-LOCA design basis events, and radiological and environmental evaluations. Stone & Webster also reviewed the impact on Seabrook Station programs and procedures.

General Electric Energy Services

General Electric Energy Services performed analyses and evaluations of the turbine-generator and accessories for the SPU conditions.

FPL Energy Seabrook

FPL Energy Seabrook prepared the LAR, performed program evaluations, assessed impact on operations, coordinated the transmission system grid stability studies, and provided technical oversight and integration of the licensing and engineering evaluations.

1.2 METHODOLOGY AND ACCEPTANCE CRITERIA

Analyses and evaluations performed for this SPU were based on the parameters generated for the uprate conditions, and when necessary, comparisons against current licensing basis values were made to assess the changes due to the SPU.

The Seabrook Station SPU methodology utilized to evaluate the impact on the NSSS was performed consistent with the guidelines set forth in Westinghouse Electric Company Topical Report, WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," dated January 1983. The topical report was submitted to the Nuclear Regulatory Commission for review in a letter from Westinghouse to the NRC dated February 11, 1983 [Reference 1.2-1]. Since submittal of WCAP-10263 to the Nuclear Regulatory Commission, the methodology has been used successfully as a basis for power uprate projects on over 25 pressurized water reactor units.

The methodology in WCAP-10263 establishes the ground rules 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 the NSSS and the 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/parameter values, use of currently approved analytical techniques (e.g., methodologies and computer codes) and use of currently applicable licensing criteria and standards.

The methodology utilized by Stone & Webster in evaluating the impact upon the BOP is consistent with the methodology used for previously approved power uprate projects for other licensees and Nuclear Regulatory Commission Review Standard RS-001 [Reference 1.3-1]. The initial task was to identify the parameters and design inputs that were to be used in various BOP system, structure and component evaluations. Detailed evaluations and analyses were then performed based upon the following categories:

- Bounded by existing analysis and design conditions
- Bounded by design with reanalysis
- Not bounded by analysis or design

This methodology is discussed in greater detail in LAR Section 8.0.

Various computer codes were utilized in the analyses and evaluations for the Seabrook Station SPU. The major codes that were used to perform engineering and licensing evaluations, and to establish safety and operating limits are listed in the LAR Table 1.2-1.

The Seabrook Station SPU analyses and evaluations were performed in accordance with the quality assurance requirements defined in the FPL Energy Seabrook Operational Quality Assurance Program that complies with 10 CFR 50, Appendix B.

These analyses and evaluations are in conformance with industry codes, standards, and regulatory requirements. Assumptions and acceptance criteria are provided in the appropriate sections of this LAR.

TABLE 1.2-1
COMPUTER CODES

Evaluation Subject	Computer Code	Previously Used at Seabrook Station	Reference LAR Section
Non-LOCA	RETRAN-02	No – see Note 1	6.3
Non-LOCA	FACTRAN	Yes	6.3
Non-LOCA	TWINKLE	Yes	6.3
Non-LOCA	LOFTRAN	Yes	6.3
Fuel	VIPRE-01	Yes	6.3, 7.1
Fuel	PAD 4.0	Yes	7.1, 7.3
Fuel	PHOENIX-P	Yes	7.2
Fuel	ANC	Yes	7.2
Fuel	APOLLO	Yes	7.2
Fuel	WEGAP	Yes	5.3
Steam Generator Tube Rupture	RETRAN	Yes	6.2
Steam Line Break Mass/Energy (Inside Containment)	RETRAN	No – see Note 1	6.4.4
Steam Line Break Mass/Energy (Outside Containment)	LOFTRAN	Yes	6.5.2
Small Break LOCA	NOTRUMP	Yes	6.1.2
Small Break LOCA	SBLOCTA	Yes	6.1.2
Large Break LOCA (Best Estimate Model)	WCOBRA/TRAC	No – see Note 2	6.1.1
Containment	GOTHIC	No – see Note 3	6.4.2, 6.4.3, 6.4.5
LOCA Mass and Energy	SATAN IV	Yes	6.4.1
LOCA Mass and Energy	SATAN VI	Yes	6.4.1
LOCA Mass and Energy	WREFLOOD	Yes	6.4.1

Notes:

1. This is the first application of the Westinghouse RETRAN methodology for these events at Seabrook Station. The methodology, presented in WCAP-14882-P-A [Reference 1.2-8], has been approved by the NRC.
2. This is the first application for these computer programs to the Seabrook Station LOCA analysis; the methodology, presented in WCAP-12945 (P) [Reference 1.2-2], has been approved by the NRC.
3. This is the first application for this computer program to the Seabrook Station Containment analysis; results based on this methodology have been approved by the NRC in license amendment requests by other licensees [References 1.2-5, 1.2-6, 1.2-7]. This code was used for comparison purposes.

TABLE 1.2-1 (continued)
COMPUTER CODES

Evaluation Subject	Computer Code	Previously Used at Seabrook Station	Reference LAR Section
LOCA Mass and Energy	FROTH	No – see Note 4	6.4.1
LOCA Mass and Energy	EPITOME	No – see Note 4	6.4.1
LOCA Forces	MULTIFLEX	Yes	6.1.7
LOCA Forces	LATFORC	Yes	6.1.7
LOCA Forces	FORCE2	Yes	6.1.7
LOCA Forces	THRUST	Yes	6.1.7
Heat Generation Rates	DORT	Yes	5.2.8
Reactor Vessel Fluence	DORT	Yes	5.1.2
Reactor Vessel Internals	THRIVE	Yes	5.2
Reactor Vessel Internals	DROP	Yes	5.2
Reactor Vessel Internals	WECAN	Yes	5.2
Reactor Vessel Internals	ANSYS	Yes	5.2
Piping	WESTDYN	Yes	5.5
Design Operating Parameters	SGPER	Yes	2.0
Control Systems	LOFTRAN	Yes	4.3
Steam Generator	GENF	Yes	5.7

Notes:

4. This is the first application for these computer programs to the Seabrook Station LOCA mass and energy release analysis; the methodology, presented in WCAP-10325-P-A [Reference 1.2-4], has been approved by the NRC.

1.3 REGULATORY GUIDANCE

This power uprate is less than a 7 percent increase and requires no major modifications. Therefore is considered to be an SPU.

There is no regulatory guidance for the development of an SPU LAR. FPL Energy Seabrook developed this LAR with the guidelines in Nuclear Regulatory Commission Review Standard, RS-001, "Review Standard for Extended Power Uprates" [Reference 1.3-1]. The guidance of RS-001 states that SPUs are characterized by power level increases up to 7 percent and do not generally involve major plant modifications. The LAR expectations of RS-001 extend beyond those historically required for an SPU . The guidance of RS-001 supports the characterization of the Seabrook Station power uprate as a stretch power uprate. A cross-reference between the LAR and the matrices in RS-001 is provided in LAR Tables 1.3-1 through 1.3-13.

TABLE 1.3-1
NRC REVIEW STANDARD RS-001
MATRIX 1

MATERIALS AND CHEMICAL ENGINEERING	LAR SECTION
Reactor Vessel Material Surveillance Program	5.1 Reactor Pressure Vessel
Pressure-Temperature Limits and Upper Shelf Energy	5.1 Reactor Pressure Vessel
Pressurized Thermal Shock	5.1 Reactor Pressure Vessel
Reactor Internal and Core Support Materials	5.2 Reactor Pressure Vessel Internals
Reactor Coolant Pressure Boundary Materials	5.0 Nuclear Steam Supply System Components 5.11 Materials
Leak-Before-Break	5.12 Application of Leak Before Break Methodology
Protective Coating Systems (Paints) – Organic Materials	9.2 Equipment Qualification Program
Effect of Power Uprate on Flow Accelerated Corrosion	9.1.3 Flow Accelerated Corrosion Program
Steam Generator Tube Inservice Inspection	5.7 Steam Generators
Steam Generator Blowdown System	8.4.5 Steam Generator Blowdown
Chemical and Volume Control System - Including Boron Recovery	4.1.4.2 Chemical and Volume Control System
Reactor Water Cleanup System (BWR)	NA

TABLE 1.3-2
NRC REVIEW STANDARD RS-001
MATRIX 2

MECHANICAL AND CHEMICAL ENGINEERING	LAR SECTION
Pipe Rupture Locations and Associated Dynamic Effects	5.5 Reactor Coolant Loop Piping and Supports 10.4 High Energy Line Break/Jet Impingement
Pressure-Retaining Components and Component Supports	4.1 Nuclear Steam Supply Fluid Systems 5.1 Reactor Pressure Vessel 5.4 Control Rod Drive Mechanisms 5.5 Reactor Coolant Loop Piping and Supports 5.6 Pressurizer 5.7 Steam Generators 5.8 Reactor Coolant Pumps and Motors 8.4 System Assessments 8.5 Piping and Supports
Reactor Pressure Vessel Internals and Core Supports	5.2 Reactor Pressure Vessel Internals
Safety-Related Valves and Pumps	4.1 Nuclear Steam Supply Fluid Systems 5.0 NSSS Components 9.1.2 Valve Programs
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	9.2 Equipment Qualification Program

TABLE 1.3-3
NRC REVIEW STANDARD RS-001
MATRIX 3

ELECTRICAL ENGINEERING	LAR SECTION
Environmental Qualification of Electrical Equipment	9.2 Equipment Qualification Program
Offsite Power System	8.4.16 Electrical
AC Onsite Power System	8.4.16 Electrical
DC Onsite Power System	8.4.16 Electrical
Station Blackout	6.3.9 Station Blackout

TABLE 1.3-4
NRC REVIEW STANDARD RS-001
MATRIX 4

INSTRUMENTATION AND CONTROLS	LAR SECTION
Reactor Trip System	4.3.1 Reactor Protection System / Engineered Safety Features Actuation System 4.3.2 Setpoint Uncertainty Analysis
Engineered Safety Features Systems	4.3.1 Reactor Protection System / Engineered Safety Features Actuation System 4.3.2 Setpoint Uncertainty Analysis
Safety Shutdown Systems	4.3.1 Reactor Protection System / Engineered Safety Features Actuation System 4.3.2 Setpoint Uncertainty Analysis
Control Systems	4.3.3 Control Systems
Diverse I&C Systems	N/A
General guidance for use of other SRP Sections related to I&C	4.3 Instrumentation and Controls

TABLE 1.3-5
NRC REVIEW STANDARD RS-001
MATRIX 5

PLANT SYSTEMS	LAR SECTION
Flood Protection	10.3 Internal Flooding
Equipment and Floor Drainage System	8.4.15.1 Rad Waste Systems
Circulating Water System	8.4.7 Main Condenser and Circulating Water
Internally Generated Missiles (Outside Containment)	Note 1
Internally Generated Missiles (Inside Containment)	Note 1
Turbine Generator	8.3 Turbine Generator and Turbine Auxiliary Systems
Protection against Postulated Piping Failures in Fluid Systems Outside Containment	10.4 High Energy Line Break / Jet Impingement
Fire Protection Program	9.1.1 Fire Protection Program
Pressurizer Relief Tank	4.1.4.1 Reactor Coolant System
Fission Product Control Systems and Structures	N/A
Main Condenser Evacuation System	8.4.6 Main Condenser Evacuation System
Turbine Gland Sealing System	8.3 Turbine Generator and Turbine Auxiliary Systems
Main Steam Isolation Valve Leakage Control System	N/A
Spent Fuel Pool Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
Auxiliary and Radwaste Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
Turbine Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
ESF Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
Spent Fuel Pool Cooling and Cleanup System	8.4.9 Spent Fuel Pool Cooling
Station Service Water System	8.4.12 Service Water
Reactor Auxiliary Cooling Water Systems	8.4.13.1 Primary Component Cooling Water
Ultimate Heat Sink	8.4.11 Ultimate Heat Sink
Auxiliary Feedwater System	8.4.4 Emergency Feedwater
Main Steam Supply System	8.4.1 Main Steam
Main Condenser	8.4.3 Condensate and Feedwater
Turbine Bypass System	8.4.1 Main Steam

Notes:

1. Based on the insignificant changes in system pressures and component overspeed conditions during plant operation and anticipated operational occurrences as a result of the Seabrook Station SPU, system, structures and components important to safety will continue to be protected from internally generated missiles and will continue to meet the requirements of GDC-4 following implementation of the SPU.

TABLE 1.3-5 (continued)
NRC REVIEW STANDARD RS-001
MATRIX 5

PLANT SYSTEMS	LAR SECTION
Condensate and Feedwater System	8.4.3 Condensate and Feedwater
Gaseous Waste Management Systems	8.4.15.1 Rad Waste Systems
Liquid Waste Management Systems	8.4.15.1 Rad Waste Systems
Solid Waste Management Systems	8.4.15.1 Rad Waste Systems
Emergency Diesel Engine Fuel Oil Storage and Transfer System	8.4.16 Electrical
Light Load Handling System (Related to Refueling)	6.6 Radiological Consequences See also Note 1

Notes:

1. This category covers the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. With regard to radioactive releases resulting from damage to irradiated fuel, see LAR Section 6.6. With regard to personnel radiation exposures and criticality accidents, the analyses and evaluations presented in Section 9.1 of the Seabrook Station UFSAR will remain valid for the fuel associated with the SPU. The maximum enrichment required for the SPU core design will remain below the upper enrichment limit (5.0%) of Section 9.1 of the Seabrook Station UFSAR. Accordingly, the light load handling system related to refueling for Seabrook Station will continue to meet the requirements of General Design Criteria 61 and 62 after implementation of the SPU.

TABLE 1.3-6
NRC REVIEW STANDARD RS-001
MATRIX 6

CONTAINMENTS	LAR SECTION
Dry Containments	6.4 Containment Response
Ice Condenser Containments	N/A
Pressure-Suppression Type BWR Containments	N/A
Subcompartment Analysis	6.4.2 Subcompartment Analysis
Mass and Energy Release for Postulated LOCA	6.4.1 Loss Of Coolant Accident (LOCA) Mass and Energy Releases
Mass and Energy Release for Postulated Secondary System Pipe Ruptures	6.4.4 Steamline Break Mass and Energy Releases Inside Containment 6.5.2 Mass and Energy Releases Outside Containment
Combustible Gas Control in Containment	6.1.6 Post-LOCA Hydrogen Generation
Containment Heat Removal	8.4.10 Containment Building Spray 8.4.14 Heating, Ventilation and Air Conditioning
Secondary Containment Functional Design	N/A
Minimum Containment Pressure Analysis for ECCS Performance Capability Studies	6.1.1 Best Estimate Large Break Loss Of Coolant Accident (LOCA) 6.4 Containment Response

TABLE 1.3-7
NRC REVIEW STANDARD RS-001
MATRIX 7

HABITABILITY, FILTRATION AND VENTILATION	LAR SECTION
Control Room Habitability System	6.6 Radiological Consequences 8.4.14 Heating, Ventilation and Air Conditioning
ESF Atmosphere Cleanup System	8.4.14 Heating, Ventilation and Air Conditioning
Control Room Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
Spent Fuel Pool Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
Auxiliary and Radwaste Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
Turbine Area Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning
ESF Ventilation System	8.4.14 Heating, Ventilation and Air Conditioning

TABLE 1.3-8
NRC REVIEW STANDARD RS-001
MATRIX 8

REACTOR SYSTEMS	LAR SECTION
Fuel System Design	5.3 Fuel Assembly Structural Analysis
Nuclear Design	7.2 Core Design 7.3 Fuel Rod Design and Performance
Thermal and Hydraulic Design	7.1 Core Thermal-Hydraulic Design
Functional Design of Control Rod Drive System	5.4 Control Rod Drive Mechanisms
Overpressure Protection during Power Operation	4.1 NSSS Fluid Systems 4.3.3 Control Systems 5.6 Pressurizer 6.3.3 Decrease in Heat Removal by the Secondary System
Overpressure Protection during Low Temperature Operation	4.3.4 Cold Overpressure Mitigation System
Reactor Core Isolation Cooling System (BWR)	N/A
Residual Heat Removal System	4.1.4.3 Residual Heat Removal System
Emergency Core Cooling System	4.1.4.4 Safety Injection 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	6.3.2 Increase in Heat Removal
Steam System Piping Failures Inside and Outside Containment	6.3.2 Increase in Heat Removal 6.4 Containment Response 6.5 Steamline Break Outside Containment 10.4 High Energy Line Break / Jet Impingement
Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulator Failure (Closed)	6.3.3.1 Loss of External Load/Turbine Trip
Loss of Non-emergency AC Power to Station Auxiliaries	6.3.3.3 Loss of Nonemergency AC Power to Plant Auxiliaries
Loss of Normal Feedwater Flow	6.3.3.2 Loss of Normal Feedwater
Feedwater System Pipe Breaks Inside and Outside Containment	6.3.3.4 Feedwater System Pipe Break
Loss of Forced Reactor Coolant Flow including Trip of Pump Motor and Flow Controller Malfunctions	6.3.4.1 Partial Loss of Reactor Coolant Flow / Complete Loss of Reactor Coolant Flow
Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	6.3.4.2 Reactor Coolant Pump Locked Rotor/Shaft Break
Uncontrolled Control Rod Assembly Withdrawal from a Sub-critical or Low Power Condition	6.3.5.1 Uncontrolled Rod Control Cluster Assembly Bank Withdrawal from Subcritical
Uncontrolled Control Rod Assembly Withdrawal at Power	6.3.5.2 Uncontrolled Rod Control Cluster Assembly Withdrawal at Power

TABLE 1.3-8 (continued)
NRC REVIEW STANDARD RS-001
MATRIX 8

REACTOR SYSTEMS	LAR SECTION
Control Rod Misoperation (System Malfunction or Operator Error)	6.3.5.3 Rod Control Cluster Assembly 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	6.3.5.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature
Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	6.3.5.5 Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant
Spectrum of Rod Ejection Accidents	6.3.5.7 Spectrum of Rod Control Cluster Assembly Rod Ejection Accidents
Spectrum of Rod Drop Accidents	6.3.5.3 Rod Cluster Control Assembly Misoperation
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that increases Reactor Coolant Inventory	6.3.6.1 Inadvertent Operation of Emergency Core Cooling System During Power Operation 6.3.6.2 Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory
Inadvertent Opening of a Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve	6.3.7.1 Inadvertent Opening of a Pressurizer Safety or Relief valve
Steam Generator Tube Rupture	6.2 Steam Generator Tube Rupture
Loss of Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	6.1 Loss of Coolant Accidents
Anticipated Transients Without Scram	6.3.8 Anticipated Transients Without Scram (ATWS)
New Fuel Storage	Note 1
Spent Fuel Storage	Note 1

Notes:

1. As noted in the applicability column for these topical areas, review is applicable if the EPU is requesting approval for new fuel. The Seabrook Station SPU LAR is not requesting approval of new fuel, thus these categories are not applicable. The analyses and evaluations presented in Section 9.1 of the Seabrook Station UFSAR will remain valid for the fuel associated with the SPU. The maximum enrichment required for the SPU core design will remain below the upper enrichment limit (5.0%) of Section 9.1 of the Seabrook Station UFSAR. Accordingly, Seabrook Station new and spent fuel storage facilities will continue to meet the requirements of GDCs 61 and 62 after implementation of the SPU.

TABLE 1.3-9
NRC REVIEW STANDARD RS-001
MATRIX 9

SOURCE TERMS AND RADIOLOGICAL CONSEQUENCES ANALYSES	LAR SECTION
Source Terms for Input into Radwaste Management Systems Analyses	8.4.15.2 Radiological Assessments
Radiological Consequence Analyses Using Alternative Source Terms	6.6 Radiological Consequences
Radiological Consequences of Main Steamline Failures Outside Containment for a PWR	6.6 Radiological Consequences
Radiological Consequences of Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	6.6 Radiological Consequences
Radiological Consequences of a Control Rod Ejection Accident	6.6 Radiological Consequences
Radiological Consequences of a Control Rod Drop Accident	6.6 Radiological Consequences
Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment	6.6 Radiological Consequences
Radiological Consequences of Steam Generator Tube Failure	6.6 Radiological Consequences
Radiological Consequences of Main Steamline Failure Outside Containment for a BWR	N/A
Radiological Consequences of a Design Basis Loss of Coolant Accident including Containment Leakage Contribution	6.6 Radiological Consequences
Radiological Consequences of a Design Basis Loss of Coolant Accident Leakage from ESF Components Outside Containment	6.6 Radiological Consequences
Radiological Consequences of a Design Basis Loss of Coolant Accident Leakage from Main Steam Isolation Valves (BWR)	N/A
Radiological Consequences of Fuel Handling Accidents	6.6 Radiological Consequences
Radiological Consequences of Spent Fuel Cask Drop Accidents	6.6 Radiological Consequences

TABLE 1.3-10
NRC REVIEW STANDARD RS-001
MATRIX 10

HEALTH PHYSICS	LAR SECTION
Radiation Sources	8.4.15.2 Radiological Assessment
Radiation Protection Design Features	8.4.15.2 Radiological Assessment
Operational Radiation Protection Program	8.4.15.2 Radiological Assessment

TABLE 1.3-11
NRC REVIEW STANDARD RS-001
MATRIX 11

HUMAN PERFORMANCE	LAR SECTION
Reactor Operating Training	11.2 Impact on Training
Training for Non-Licensed Plant Staff	11.2 Impact on Training
Operating and Emergency Operating Procedures	11.1 Impact on Operations Department Procedures
Human Factors Engineering	11.4 Human Factors

TABLE 1.3-12
NRC REVIEW STANDARD RS-001
MATRIX 12

POWER ASCENSION AND TESTING PLAN	LAR SECTION
Power Ascension and Testing	12.0 Testing

TABLE 1.3-13
NRC REVIEW STANDARD RS-001
MATRIX 13

RISK EVALUATION	LAR SECTION
Risk Evaluation	10.5 Probabilistic Safety Assessment

1.4 NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION BASIS

FPL Energy Seabrook has evaluated the proposed changes identified in LAR Attachments 2 and 3 pursuant to 10 CFR 50.91 against the standards in 10 CFR 50.92 and has determined that the operation of Seabrook Station in accordance with the proposed LAR presents no significant hazards. The FPL Energy Seabrook evaluation against each of the criteria in 10 CFR 50.92 is provided in Attachment 6 of this LAR.

A comprehensive review of the accident analyses, component and system analyses, and radiological dose consequences was performed for the Seabrook Station SPU. Analyses satisfied the appropriate acceptance criteria, as discussed in the no significant hazards determinations in LAR Attachment 6. Therefore, operation of Seabrook Station in accordance with the proposed amendment will not result in a significant increase in the probability or consequences of any accident previously analyzed; will not result in a new or different kind of accident from any accident previously analyzed; and will not result in a significant reduction in a margin of safety. Therefore, the proposed LAR does not involve a significant hazards consideration.

1.5 CONCLUSIONS

The analyses and evaluations presented in this LAR conclude that Seabrook Station can safely operate within licensed parameters at the SPU power level.

1.6 REFERENCES

1.1-1 FPLE letter (NYN-03061) to NRC Document Control Desk, License Amendment Request (LAR) 03-02 for Docket No. 50-443, "Implementation of Alternative Source Term", October 6, 2003.

1.2-1 Westinghouse Electric Company Topical Report, WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," January 1983.

1.2-2 R.C. Jones (USNRC) letter to N.J. Liparulo (Westinghouse), "Acceptance for Referencing of the Topical Report WCAP-12945 (P) "Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Analysis," June 1996.

1.2-3 "Westinghouse Mass and Energy Release Data for Containment Design," WCAP-8264-P-A, Revision 1, WCAP-8264-P-A (Proprietary), WCAP-8312 (Nonproprietary), August 1975.

1.2-4 "Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version," WCAP-10325-P-A (Proprietary), WCAP-10326-A (Nonproprietary).

1.2-5 A. C. MCMurtray (NRC) letter to T. Coutu (Nuclear Management Company, LLC), "Kewaunee Nuclear Power Plant – Issuance of Amendment (TAC No. MB6408)," September 29, 2003.

1.2-6 L. N. Olshan (NRC) letter to R. A. Jones (Duke Energy Corporation), "Oconee Nuclear Station, Units 1, 2 and 3 – Safety Evaluation of Revisions to Topical Reports DPC-NE-3000, -3003, and –3005 (TAC Nos. MB5441, MB5442, and MB5443)," September 24, 2003.

1.2-7 A. B. Wang (NRC) letter to R. T. Ridenoure (Omaha Public Power District), "Fort Calhoun Station, Unit 1 – Issuance of Amendment (TAC No. MB7496)," November 5, 2003.

1.2-8 WCAP –14882, "Retran-02 Modeling and Qualification of Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses", June 1997.

1.3-1 "Review Standard for Extended Power Uprates", RS-001, U. S. Nuclear Regulatory Commission, December 2003.

SEABROOK STATION

SECTION 2.0

NUCLEAR STEAM SUPPLY SYSTEM PARAMETERS

2.0 NUCLEAR STEAM SUPPLY SYSTEM PARAMETERS

The Seabrook Station Stretch Power Uprate (SPU) Project included Nuclear Steam Supply System (NSSS) performance analyses to develop bounding NSSS design operating parameters for use in the analyses and evaluations of the NSSS. These included parameters for NSSS design transients and analyses of systems, components, accidents, and nuclear fuel.

2.1 INTRODUCTION AND BACKGROUND

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

These parameters are established using conservative assumptions in order to provide bounding conditions to be used in the NSSS analyses. For example, the Reactor Coolant System flow assumed in generating the primary and secondary side conditions is the thermal design flow, which is a conservatively low flow that accounts for flow measurement uncertainty and assumes the maximum steam generator tube plugging level. The design operating parameters were determined such that FPL Energy Seabrook would have operating flexibility; therefore, a range of conditions was established for the vessel average temperature (T_{avg}), the steam generator tube plugging level, and feedwater temperature (T_{feed}). The T_{avg} range was specified between 571.0°F and 589.1°F, the steam generator tube plugging level can vary from 0% to 10%, and the T_{feed} range was specified between 390°F and 452.4°F. The analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and a thermal design flow value of 93,600 gpm/loop were used to generate the design operating parameters.

2.2 INPUT PARAMETERS AND ASSUMPTIONS

The major input parameters and assumptions established for the SPU are summarized below:

- The power level for the SPU was set at an analyzed core power level of 3659 MWt (3678 MWt NSSS power level). A thermal design flow of 93,600 gpm/loop was also assumed.
- The steam generator tube plugging values assumed were 0% and 10% at both ends of the analyzed T_{avg} range.
- Design core bypass flow was assumed to be 8.3%, which accounts for thimble plug removal and intermediate flow mixers. Analyses bound core conditions with thimble plugs in or out.

- A range of full-power, normal-operating T_{avg} from 571.0°F to 589.1°F was selected for the analyses.
- The parameters are applicable to the Model F steam generators.
- A T_{feed} range from 390.0°F to 452.4°F was established.
- Fuel Type: 17x17 robust fuel assembly fuel with intermediate flow mixers. Since a full core of robust fuel assembly fuel will be loaded for the SPU core, it is not necessary to consider transition core effects.

2.3 DISCUSSION OF PARAMETER CASES

LAR Table 2.3-1 provides the NSSS design parameter cases generated and used as the basis for the Seabrook Station SPU. The existing parameters are also shown in LAR Table 2.3-1 for comparison purposes.

Cases 1 and 2 were based on the maximum T_{avg} of 589.1°F with 0% and 10% steam generator tube plugging levels, respectively. Likewise, Cases 3 and 4 were developed for the minimum T_{avg} of 571.0°F with 0% and 10% steam generator tube plugging levels, respectively. These parameters form the basis for the SPU NSSS analyses and evaluations. When a high steam generator pressure is conservative (i.e., results in the least margin), however, best estimate or bounding steam conditions are used in the analyses, as appropriate.

2.4 ACCEPTANCE CRITERIA

The primary acceptance criteria for the determination of the SPU parameters was that the parameters must provide FPL Energy Seabrook with adequate flexibility and margin for plant operation.

2.5 RESULTS AND CONCLUSIONS

The resulting parameters, shown in LAR Table 2.3-1, were used in the SPU analytical efforts. The analyses and evaluations were performed based on the parameter sets that were most limiting, so that the analyses would support operation over the range of conditions specified.

The proposed operating point has been evaluated and the operating parameters at SPU conditions are acceptable.

TABLE 2.3-1
DESIGN OPERATING PARAMETERS

Thermal Design Parameters	Existing	Case 1	Case 2	Case 3	Case 4
NSSS Power, MWt	3429	3678[1]	3678[1]	3678[1]	3678[1]
NSSS Power, 10^6 BTU/hr	11,702	12,550	12,550	12,550	12,550
Reactor Power, MWt	3411	3659[2]	3659[2]	3659[2]	3659[2]
Reactor Power, 10^6 BTU/hr	11,639	12,485	12,485	12,485	12,485
Thermal Design Flow, Loop, gpm	95,700	93,600[3]	93,600[3]	93,600[3]	93,600[3]
Thermal Design Flow, 10^6 lb/hr (Total)	142.1	139.4	139.4	143.0	143.0
Core Bypass, %	6.3	8.3[4]	8.3[4]	8.3[4]	8.3[4]
Reactor Coolant Temperatures					
Core Outlet, °F	621.7	626.5	626.5	609.7	609.7
Vessel Outlet, °F	618.2	621.4	621.4	604.3	604.3
Core Average, °F	592.0	593.8	593.8	575.5	575.5
Vessel Average, °F	588.5	589.1	589.1	571.0	571.0
Vessel/Core Inlet, °F	558.8	556.8	556.8	537.7	537.7
Steam Generator Outlet, °F	558.5	556.4	556.4	537.4	537.4
Zero Load Temperature, °F	557	557	557	557	557
Steam Generators					
Steam Temperature, °F	543.2	540.0[5,6]	537.5[5,6]	520.3[5,6]	517.8[5,6]
Outlet Steam Pressure, psia	989	962[5,6]	943[5,6]	815[5,6]	797[5,6]
Steam Flow, 10^6 lb/hr total	15.15	16.52/15.17	16.51/15.16	16.42/15.08	16.41/15.07
Feed Temperature, °F	440	452.4 / 390	452.4 / 390	452.4 / 390	452.4 / 390
Steam Generator Tube Plugging, %	0	0	10	0	10
Hydraulic Design Parameters					
Mechanical Design Flow, gpm (total)	416,800	416,800	416,800	416,800	416,800
Minimum Measured Flow, gpm (total)	392,800	383,800[7]	383,800[7]	383,800[7]	383,800[7]

Notes:

1. Reactor coolant pump heat addition was rounded from 18.4 MWt to 19 MWt. This assumption is more conservative and bounds the specified operating conditions.
2. Represents upper limit on core thermal power.
3. Reduced thermal design flow is conservatively set for 10% tube plugging.
4. Core bypass flow includes 2.0% for thimble plug removal and 0.5% for intermediate flow mixers. Seabrook Station currently has thimble plugs installed, but could elect to remove them in the future. Analyses will cover thimble plugs in or out.
5. 18 psi steam generator internal pressure drop incorporated.
6. Design values for analyses. Where high steam generator pressure and/or temperature are more conservative, best estimate or bounding values are used.
7. Reflects Technical Specification flow measurement uncertainty of 2.5%. Supports 10% steam generator tube plugging level and reduced thermal design flow.

SEABROOK STATION

SECTION 3.0

DESIGN TRANSIENTS

3.0 DESIGN TRANSIENTS

This section discusses the generation of design transients for the Seabrook Station SPU. The design transients were reviewed and revised as necessary, for use at the SPU conditions. The revised Nuclear Steam Supply System (NSSS) design transient curves were utilized as input to system and component specific analyses.

3.1 NUCLEAR STEAM SUPPLY SYSTEM DESIGN TRANSIENTS

3.1.1 INTRODUCTION

In the original design and analyses of the NSSS components for Seabrook Station, NSSS design transients (i.e., temperature and pressure transients) were specified for use in the analyses of the cyclic behavior of the NSSS components. To provide the necessary high degree of integrity for the NSSS components, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various plant operating conditions. The transients used in the component fatigue analyses were selected based on the following:

- They are representative of conditions that would be considered to occur during plant operations; and
- The impact to component cyclic behavior due to transient severity or frequency.

The selected transients are representative of plant transients which, when used as a basis for component fatigue analysis, would provide confidence that the component is appropriate for its application over the operating license period of the plant. For purposes of analysis, the number of transient occurrences is conservatively based on the original design basis for Seabrook Station.

3.1.2 INPUT PARAMETERS AND ASSUMPTIONS

NSSS design transients are based primarily on the NSSS design parameters developed to support an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) as discussed in LAR Section 2.0. The parameters upon which the original NSSS design transients were based were compared to the parameters for the SPU and are different with respect to Reactor Coolant System vessel average temperature, steam pressure and feedwater temperature. These differences were sufficient to reassess the original NSSS design transients and to require that revised NSSS design transients be evaluated for the SPU.

3.1.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

A bounding set of design transients was established, based upon the range of reactor coolant temperatures evaluated for the SPU. The revised transients were considered in the structural and fatigue analyses for the SPU. The design transients are listed in LAR Table 3.1-1. This table also denotes the transients that were revised for the SPU.

3.1.4 ACCEPTANCE CRITERIA AND RESULTS

The NSSS design transients are input to the primary and secondary component structural and fatigue analysis / evaluations. The final acceptance is determined by the component stress and fatigue analyses presented in LAR Section 5.0.

Consistent with the original NSSS design transients, the revised NSSS design transients for the SPU are conservative representations of transients which, when used as a basis for component fatigue analyses, provide confidence that the component is appropriate for its application over the operating license period of the plant. Also, consistent with the original NSSS design transients; the number of transient occurrences is based on the original design basis for Seabrook Station.

3.1.5 CONCLUSIONS

Revised design transients were specified for the Seabrook Station SPU. These revised transients are used in the NSSS component structural and fatigue evaluations at SPU conditions. The results of the component evaluations are provided in LAR Section 5.0.

3.2 AUXILIARY EQUIPMENT DESIGN TRANSIENTS

3.2.1 INTRODUCTION

The Seabrook Station auxiliary equipment design specifications included transients that were used to design and analyze the auxiliary nozzles connected to the Reactor Coolant System and certain 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. The transients are considered to be of such magnitude and/or frequency as to be significant in the component design and fatigue evaluation processes. The transients are sufficiently conservative, such 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. As part of the Seabrook Station 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 performed based on the range of NSSS design parameters developed to support an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The approved range of NSSS design parameters for the SPU were compared with the NSSS design parameters used to develop the current design bases transients. The current design bases transients for Seabrook Station are listed in Seabrook Station UFSAR Table 3.9(N)-1, "Summary of Reactor Coolant System Design Transients".

3.2.3 DESCRIPTION OF ANALYSES AND EVALUATION

An evaluation of the current design transients was performed to determine which transients could be potentially impacted by the SPU. The evaluation concluded that only those design transients associated with full-load Reactor Coolant System cold leg design temperature could be potentially impacted by the SPU.

These temperature transients are defined by the differences between the temperature of the coolant in the Reactor Coolant System cold legs and the temperature of the coolant in the auxiliary systems connected to the Reactor Coolant System cold legs. The greater the temperature difference, the greater the impact these design transients have on the auxiliary component design and fatigue evaluation processes. The current design transients are based on a full-load Reactor Coolant System cold leg temperature (T_{cold}). Since the operating coolant temperatures in the auxiliary systems are not impacted by the SPU, differences between this temperature and the SPU full-load T_{cold} were evaluated to determine the impact on these design transients.

3.2.4 ACCEPTANCE CRITERIA AND RESULTS

A comparison of the range of NSSS cold leg design temperatures for SPU at full-load, that is T_{cold} (537.7°F – 556.8°F) with the current T_{cold} value (558.8°F), indicates that the SPU temperature range is lower. These lower full-load operating temperatures result in lower temperature differences between Reactor Coolant System cold leg temperature and the lower operating temperatures in the auxiliary systems connected to the Reactor Coolant System, thereby resulting in less severe transients.

3.2.5 CONCLUSIONS

Auxiliary equipment transients that can be potentially impacted by the SPU are those temperature transients related to full-load NSSS cold leg design temperature. A review of these temperature transients indicated that changes in the transients based on the SPU design parameters were less severe. Therefore, the current auxiliary equipment design transients for Seabrook Station remain as presented in Seabrook Station UFSAR Table 3.9 (N)-1 bounding for the SPU.

TABLE 3.1-1
SUMMARY OF REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

	TRANSIENT	REVISED FOR SPU
	Normal Conditions	
1.	Heatup and cooldown at 100°F/hr (pressurizer cooldown 200°F/hr)	No
2.	Unit loading and unloading at 5%/minute	Yes
3.	Step load increase and decrease of 10% of full power	Yes
4.	Large step load decrease with steam dump	Yes
5.	Steady-state fluctuations a. Initial fluctuations b. Random fluctuations	 No No
6.	Feedwater cycling at hot shutdown	No
7.	Loop out of service a. Normal loop shutdown b. Normal loop startup	 No No
8.	Unit loading and unloading between 0% and 15% of full power	Yes
9.	Boron concentration equalization	No
10.	Refueling	No
11.	Reduced temperature return to power	Yes
12.	Reactor coolant pumps startup/shutdown	No
13.	Turbine roll test	No
14.	Primary side leakage test	No
15.	Secondary side leakage test	No
16.	Tube leakage test	No
	Upset Conditions	
1.	Loss of load, without immediate reactor trip	Yes
2.	Loss of power (blackout with natural circulation in the Reactor Coolant System)	Yes
3.	Partial loss of flow (loss of one pump)	Yes
4.	Reactor trip from full power a. Without cooldown b. With cooldown, without safety injection c. With cooldown and safety injection	 Yes Yes Yes

TABLE 3.1-1 (continued)
SUMMARY OF REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

	TRANSIENT	REVISED FOR SPU
	Upset Conditions (continued)	
5.	Inadvertent reactor coolant depressurization	Yes
6.	Inadvertent startup of an inactive loop	No
7.	Control rod drop	No
8.	Inadvertent emergency core cooling system actuation	Yes
9.	Operational basis earthquake (5 earthquakes of 10 cycles each)	No
10.	Excessive feedwater flow	No
	Emergency Conditions	
1.	Small loss of coolant accident	Yes
2.	Small Steam Line Break	No
3.	Complete Loss of Flow	Yes
	Faulted Conditions	
1.	Main reactor coolant pipe break (large loss of coolant accident)	No
2.	Large steam line break	No
3.	Feedwater line break	No
4.	Reactor coolant pump locked rotor	No
5.	Control rod ejection	No
6.	Steam generator tube rupture	Note 1
7.	Safe shutdown earthquake	No
	Test Conditions	
1.	Primary side hydrostatic test	No
2.	Secondary side hydrostatic test	No

Note:

1. Included under upset conditions, reactor trip from full power with safety injection.

SEABROOK STATION

SECTION 4.0

NSS/BOP INTERFACE SYSTEMS

4.0 NUCLEAR STEAM SUPPLY SYSTEMS

This section discusses the impact of the Seabrook Station SPU on the functional design requirements of the:

- Nuclear Steam Supply System (NSSS),
- NSSS/Balance of Plant (BOP) fluid systems interfaces, and
- Instrumentation and Controls (I&C) systems.

The NSSS and its systems and components were verified to be capable of performing their intended design functions at SPU conditions. The control systems associated with the NSSS were evaluated and found acceptable for operation at SPU conditions.

The structural integrity of the NSSS components has been evaluated and is discussed in LAR Section 5.0.

4.1 NSSS FLUID SYSTEMS

4.1.1 INTRODUCTION AND BACKGROUND

As part of the evaluation for the Seabrook Station SPU, the following fluid systems were reviewed to confirm continued compliance with regulatory requirements, and applicable performance and design basis requirements:

- Reactor Coolant System
- Chemical and Volume Control System
- Residual Heat Removal System
- Safety Injection System

The fluid systems evaluations described in this section were performed at the system level.

4.1.2 INPUT PARAMETERS AND ASSUMPTIONS

The review was performed based on the range of NSSS design parameters shown in LAR Section 2.0, which were developed to support the Seabrook Station SPU.

The range of SPU NSSS design parameters were compared with the current design parameters previously evaluated for systems and components. The comparison indicated differences that could impact the performance of the above fluid systems. For example, the SPU would result in a proportional increase in the residual heat load after reactor shutdown that must be removed by the Residual Heat Removal System during plant cooldown.

4.1.3 ACCEPTANCE CRITERIA

The evaluations of the above fluid systems relative to applicable performance and design basis requirements are delineated in LAR Subsection 4.1.4. The acceptance criteria are included in LAR Subsection 4.1.4 along with the system evaluations, results, and conclusions.

4.1.4 DESCRIPTION OF FLUID SYSTEMS EVALUATIONS AND RESULTS

4.1.4.1 REACTOR COOLANT SYSTEM

The changes in NSSS design parameters that affect the Reactor Coolant System design basis functions include the increase in core power and the allowable range for average Reactor Coolant System temperature (T_{avg}). This section of the report will discuss the Reactor Coolant System supporting fluid system designs. These system designs include the pressurizer spray flow performance, the pressurizer relief valve performance, the pressurizer surge line performance, and the Reactor Coolant System setpoints (including the pressurizer relief tank). The pressurizer code safety valves and associated piping were addressed in the LAR Subsection 6.3.3.1. The

evaluation of the Seabrook Station SPU operating conditions demonstrates that the Reactor Coolant System continues to meet the applicable design basis functions.

4.1.4.1.1 PRESSURIZER SPRAY FLOW PERFORMANCE

Pressurizer spray (valves and piping) was originally designed to pass the design spray valve minimum flow rate of 900 gpm with an available pressure drop equal to the pressure drop from the spray flow scoop on two cold legs to the pressurizer surge line connection on the hot leg. The design basis for the 900 gpm spray flow rate is to prevent challenges to the pressurizer power operated relief valves for a 10% step change in load. The 900 gpm spray flow rate is confirmed to meet this design basis requirement for SPU conditions in LAR Subsection 4.3.3.1.2. The available pressure drop to achieve design spray flow is based on Best Estimate Reactor Coolant System loop flow and the range of Reactor Coolant System design temperatures for T_{cold}. The most significant parameter is Best Estimate flow. An overall hydraulic evaluation concluded that the spray system flow rate would be greater than, or equal to, the design flow rate for the full range of parameters applicable to the Seabrook Station SPU.

The results of the evaluation showed that the pressurizer spray flow rate will continue to be acceptable (>900 gpm) considering the Seabrook Station SPU conditions. Therefore, the SPU does not impact the pressurizer spray flow rate design basis function.

4.1.4.1.2 PRESSURIZER RELIEF VALVE PERFORMANCE

Each of the two pressurizer power operated relief valves are designed to discharge a minimum of 210,000 lbm/hr (at 2385 psig of saturated steam) in order to limit the undesirable opening of the pressurizer safety valves. The required relief capacity was reconfirmed for SPU conditions in LAR Subsection 4.3.3.1.1. This evaluation was primarily based on the pressurizer steam conditions, which do not change for the SPU (saturated steam at power operated relief valve set pressure, 2385 psig; i.e., ~662°F). Therefore, the SPU does not impact the ability of the pressurizer power operated relief valves to perform their design basis function.

4.1.4.1.3 PRESSURIZER SURGE LINE PERFORMANCE

An evaluation of the surge line indicated that the SPU conditions do not significantly impact the surge line performance. Therefore, the flow resistances and associated friction losses calculated for the surge line in the analysis of record remain valid and applicable to Seabrook Station at SPU conditions. There are no acceptance criteria associated with the surge line flow resistances and associated friction losses values; these values are used as input to various safety analyses. In conclusion, the SPU does not impact the analysis of record for the pressurizer surge line.

4.1.4.1.4 REACTOR COOLANT SYSTEM SETPOINTS

The Reactor Coolant System instrumentation control setpoints were reviewed for potential impact as a result of operating at SPU conditions. The only setpoints requiring further evaluation were those associated with the pressurizer relief tank.

For the pressurizer relief tank setpoints, since the loss-of-external-electrical-load transient analysis determined that the actual discharge of steam from the pressurizer into the pressurizer relief tank is significantly less than the design bases discharge, the design of the pressurizer relief tank and existing level setpoints remain conservative. The current pressurizer relief tank level setpoints ensure adequate coolant is maintained in the tank to condense and cool the design bases discharge and preclude tank pressure from exceeding 50 psig. Therefore, the pressurizer relief tank setpoints are not impacted by the SPU.

There are no other Reactor Coolant System instrumentation control setpoints impacted by the Seabrook Station SPU.

4.1.4.2 CHEMICAL AND VOLUME CONTROL SYSTEM

The changes in NSSS design parameters that could potentially impact the Chemical and Volume Control System design bases functions include the increase in core power and the range for Reactor Coolant System full-load design temperatures. The increase in core power and the range for Reactor Coolant System full-load design temperatures may affect the Chemical and Volume Control System design bases related to the core reload boron requirements. Additionally, the allowable range for Reactor Coolant System full-load design temperatures may impact the heat loads that the Chemical and Volume Control System heat exchangers must transfer to the Primary Component Cooling Water System, and in the case of the regenerative heat exchanger, to the normal charging flow. The applicable General Design Criteria for the Chemical and Volume Control System are 14 and 29.

4.1.4.2.1 SYSTEM HEAT LOADS

The Chemical and Volume Control System is designed to maintain Reactor Coolant System water inventory, boron concentration, and water chemistry. Other Reactor Coolant System support functions include purification and seal injection flow to the reactor coolant pumps. During normal operation, the Chemical and Volume Control System services the Reactor Coolant System by a letdown-and-charging process. Reactor Coolant System flow is letdown to the Chemical and Volume Control System and delivered back to the Reactor Coolant System via charging pumps. This process requires that these feed-and-bleed streams be cooled and re-heated via heat exchangers. Since the Seabrook Station SPU alters Reactor Coolant System operating temperatures, the following Chemical and Volume Control System heat exchangers were evaluated to assess the impact on the duty of these heat exchangers:

- Regenerative heat exchanger
- Letdown heat exchanger
- Excess letdown heat exchanger
- Seal water heat exchanger

4.1.4.2.2 REGENERATIVE HEAT EXCHANGER

The regenerative heat exchanger is designed to recover heat from the letdown flow by reheating the charging flow to minimize Reactor Coolant System heat losses. Heating the charging line fluid before it enters the Reactor Coolant System is also required to minimize thermal transients on the Reactor Coolant System charging line nozzles. The design basis heat load was based on a maximum Reactor Coolant System T_{cold} temperature of 560°F. Since the expected full-load T_{cold} for the Seabrook Station SPU is less than 560°F, the heat exchanger duty is less severe than the design duty. The Reactor Coolant System pressure of 2235 psig was used in the design calculation and remains unchanged for the SPU. Therefore, the Seabrook Station SPU has no impact on the regenerative heat exchanger performance.

4.1.4.2.3 LETDOWN HEAT EXCHANGER

The letdown heat exchanger cools the letdown flow leaving the regenerative heat exchanger to a temperature that is compatible with the purification demineralizer resins and the reactor coolant pump seals. The required temperature of the letdown flow at the exit of the letdown heat exchanger is automatically controlled by a temperature controller and temperature control valve that regulates the flow of primary component cooling water that passes through the heat exchanger. The design basis heat load was based on a maximum inlet temperature of 290°F. Since the maximum design regenerative heat exchanger inlet temperature is greater than the corresponding temperature for the Seabrook Station SPU, the inlet temperature to the letdown heat exchanger is less than the design value. Since the duty on the letdown heat exchanger for the SPU is less than the design duty, there is no impact on the letdown heat exchanger performance.

4.1.4.2.4 EXCESS LETDOWN HEAT EXCHANGER

The excess letdown heat exchanger can be employed either when normal letdown is temporarily out of service to maintain plant operation, or it can be used to supplement maximum letdown flow during the final stages of plant heatup. The original design specification heat load was based on a maximum Reactor Coolant System T_{cold} temperature of 560°F. Since the expected full-load T_{cold} for the SPU is less than design, the duty on this heat exchanger is less severe than the design duty. Therefore, there is no impact on the excess letdown heat exchanger performance.

4.1.4.2.5 SEAL WATER HEAT EXCHANGER

The seal water heat exchanger is designed to cool the fluid from two sources:

- Reactor coolant pump seal water returning to the volume control tank
- Reactor coolant discharged from the excess letdown heat exchanger

The first source of heat is not affected by the NSSS design parameters for the SPU. The second heat source is reduced because the expected Reactor Coolant System full-load T_{cold} temperature is less than 560°F (the original heat exchanger design

specification temperature) entering the excess letdown heat exchanger. Therefore, the duty on the seal water heat exchanger for the SPU is less severe than the design duty. Therefore, there is no impact on the seal water heat exchanger performance.

In summary, the heat duty on the Chemical and Volume Control System heat exchangers is acceptable based on the NSSS design parameters for the Seabrook Station SPU.

4.1.4.2.6 LETDOWN LINE DECAY TIME (N-16 DELAY TIME)

The letdown line decay time calculation requires that the letdown line, from its connection to the Reactor Coolant System to the point where it leaves the containment, contain sufficient volume to delay the flow for one minute during maximum flow conditions. This delay time is required to permit N-16 activity in the reactor coolant to decay to an acceptable value. The design basis requirement for letdown line decay time is 60 seconds. The letdown line decay time calculated for Seabrook Station is 66 seconds. This 10% margin above the required delay time is sufficient to counteract the additional N-16 activity due to the SPU. Based on the available margin in the delay time and the NSSS design parameters for the Seabrook Station SPU there is no impact to the letdown line decay time.

4.1.4.3 RESIDUAL HEAT REMOVAL SYSTEM

The Residual Heat Removal System is designed to remove sensible and decay heat from the core and to reduce the temperature of the Reactor Coolant System during the second phase of plant cooldown. As a secondary function, the Residual Heat Removal System is used to transfer refueling water between the refueling water storage tank and the refueling cavity at the beginning and end of refueling operations. The applicable General Design Criteria for the Residual Heat Removal System are 15, 19, and 34.

The Residual Heat Removal System consists of two residual heat removal heat exchangers, two residual heat removal pumps and associated piping, valves and instrumentation. During system operation, coolant flows from one hot leg of the Reactor Coolant System to the residual heat removal pumps, through the tube side of the residual heat removal heat exchangers and back to two Reactor Coolant System cold legs. The residual heat removal heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while primary component cooling water circulates through the shell.

The Seabrook Station SPU results in a higher power level, which results in an increase in the amount of decay heat being generated in the core. This will result in a higher heat load on the residual heat removal heat exchangers during plant cooldown and also during refueling. The increased heat loads will be transferred to the Primary Component Cooling Water System and ultimately to the Service Water System (LAR Subsections 8.4.13.1 and 8.4.12, respectively). Evaluation of the performance of the Residual Heat Removal System in conjunction with the Primary Component Cooling Water System and Service Water System with the increased

heat loads is addressed in the following sections. Residual Heat Removal System analysis parameters are summarized in LAR Table 4.1-1.

4.1.4.3.1 NORMAL PLANT COOLDOWN

During actual plant operations, Residual Heat Removal System cooldown is initiated approximately 4 hours after reactor shutdown, when the Reactor Coolant System temperature is 350°F or less. For conservatism, the cooldown analysis is modeled according to the original design basis, which initiated the cooldown at 350°F. The design basis for normal cooldown assumes that the Reactor Coolant System is cooled by the secondary system from 557°F to 350°F within 4 hours after reactor shutdown.

For normal operation, with two Residual Heat Removal System trains available, the Residual Heat Removal System is designed to reduce the temperature of the Reactor Coolant System from 350°F to 125°F within 20 hours when the service water temperature is 65°F. As described in the Seabrook Station UFSAR Section 5.4.7, this performance specification was chosen as the system design basis to ensure that the Residual Heat Removal System cooldown did not limit refueling operations.

The residual heat load for the Seabrook Station SPU is based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Normal cooldown is accomplished with two residual heat removal heat exchangers and two primary component cooling water heat exchangers in service.

The results and conclusions of this normal plant cooldown analysis are as follows:

- The cooldown evaluation determined the time required for a two train cooldown from 350°F to 125°F. The resultant time is within the cooldown time presented in Seabrook Station UFSAR of 20 hours.
- The Seabrook Station UFSAR also states a design basis time of 3 hours to cool down the reactor coolant from 350°F to 212°F. The cool down time calculated for the Seabrook Station SPU to reduce the reactor coolant from 350°F to 212°F is within 3 hours.

Based on the results of the Residual Heat Removal System cooldown evaluation at the Seabrook Station SPU operating conditions, the Residual Heat Removal System performance remains acceptable for the SPU conditions.

4.1.4.3.2 SINGLE TRAIN COOLDOWN

The Seabrook Station Technical Specifications require the plant to be in Cold Shutdown Mode (T≤200°F, Mode 5) within 37 hours when a shutdown is required during power operation. Technical Specification Limiting Conditions for Operation, require at least one residual heat removal loop in operation. The Seabrook Station UFSAR states that with one train of the Residual Heat Removal System in operation, the reactor coolant is reduced from 350°F to 200°F within 33.5 hours and from 350°F to 212°F in less than 23 hours.

The calculated single train cooldown times for the SPU conditions meet both the Technical Specifications requirement that the plant be in Cold Shutdown mode within 37 hours and the design basis for single train Residual Heat Removal System performance described in the Seabrook Station UFSAR.

Based on the results of the Residual Heat Removal System cooldown evaluation for the Seabrook Station SPU operating conditions there is no impact on Residual Heat Removal System performance requirements for cooldown operation with a single train available.

4.1.4.3.3 APPENDIX R AND SAFE SHUTDOWN COOLDOWN

The Seabrook Station UFSAR outlines the systems required for safe shutdown. The Residual Heat Removal System is required for long term plant cooldown in order to transfer decay heat from the Reactor Coolant System to the Primary Component Cooling Water System.

Per Seabrook Station UFSAR Section 5.4.7, the safe shutdown design basis for Seabrook Station is hot standby. The cold shutdown capability of the plant was analyzed to demonstrate that the plant can be brought to a cold shutdown condition using only safety-grade equipment following a safe shutdown earthquake, loss of off-site power, and the most limiting single failure. The plant is capable of achieving Residual Heat Removal System entry conditions (350°F or less and 400 psig) in 9 hours, which includes four hours at hot standby. The selected method of achieving cold shutdown condition for Seabrook Station is natural circulation without Reactor Coolant System letdown. The natural circulation cooldown capability for SPU conditions has been evaluated (in LAR Section 10.2), and it has been determined that the Residual Heat Removal System entry conditions will continue to be achieved in 9 hours. This is compatible with the current licensing bases for condensate storage tank inventory at SPU conditions (LAR Subsection 4.2.3.4.1). At this point, the Residual Heat Removal System is placed in service to complete the cooldown to cold shutdown conditions. There is no cooldown time criteria associated with reaching cold shutdown. With one Residual Heat Removal System train in operation, the reactor coolant pump heat load at zero (i.e., the reactor coolant pumps are not operating), and the Residual Heat Removal System cooldown initiated at 9 hours, the time required to reach 200°F is 18 hours after reactor shutdown. The resulting cooldown time from 350°F to 200°F is 9 hours.

10 CFR 50 Appendix R requires cooldown to cold shutdown in 72 hours with one train of the Residual Heat Removal System. Therefore, the above evaluation demonstrates that the Residual Heat Removal System, in conjunction with the Primary Component Cooling Water System and Service Water System, is adequately sized to meet both the Appendix R and safe shutdown regulatory requirements for the SPU.

4.1.4.4 SAFETY INJECTION SYSTEM

The required volume, duration, and heat rejection capability of the Safety Injection System flows in the event of postulated Reactor Coolant System and Main Steam

System breaks are determined based on analytical and empirical models that simulate reactor and containment conditions subsequent to the breaks. As a result of these analyses, the system and component criteria necessary to demonstrate compliance with regulatory requirements at the SPU power level are established. Since the results of these analyses (LAR Section 6.0) have demonstrated that the Safety Injection System provides adequate safety margin, the Safety Injection System is acceptable for the SPU. The applicable General Design Criteria for the Safety Injection System are 27 and 35. Since the Safety Injection System meets its design basis, the applicable General Design Criteria are met.

4.1.5 CONCLUSIONS

A summary of the conclusions of the evaluations of the NSSS fluid systems for the Seabrook Station SPU is provided below.

4.1.5.1 REACTOR COOLANT SYSTEM

The hydraulic design of the pressurizer surge line, safety valve inlet and outlet piping, and the design capacity of the pressurizer relief tank are adequate for the SPU.

The hydraulic design of the pressurizer power operated relief valve inlet and discharge piping is adequate for the SPU.

The hydraulic design of the pressurizer spray system (piping and valves) is adequate to achieve design spray capacity considering the SPU NSSS design parameters.

4.1.5.2 CHEMICAL AND VOLUME CONTROL SYSTEM

The heat loads imposed on the Chemical and Volume Control System heat exchangers due to the Seabrook Station SPU are less than the design basis heat loads. Since the Chemical and Volume Control System meets its design basis, General Design Criteria 14 and 19 are met.

4.1.5.3 RESIDUAL HEAT REMOVAL SYSTEM

The Residual Heat Removal System, in conjunction with the Primary Component Cooling Water System and the Service Water System, is adequately sized for normal cooldown heat loads associated with the SPU. Since the Residual Heat Removal System meets its design basis, General Design Criteria 15, 19, and 34 are met.

4.1.5.4 SAFETY INJECTION SYSTEM

The Safety Injection System provides adequate safety margin for the SPU.

TABLE 4.1-1
RESIDUAL HEAT REMOVAL COOLDOWN ANALYSIS PARAMETERS FOR SEABROOK STATION SPU

RHRCOOL Input Parameter	Units	Value
Decay heat model	Decay Heat in MBTU/hr	BOP Curve[1]
Reactor power level for use in calculating decay heat	MWt	3659.00
Design UA for primary component cooling water heat exchanger	MBTU/HR/°F	8.29
Design UA for residual heat removal heat exchanger	MBTU/HR/°F	2.02
Design Reactor Coolant System flow through one residual heat removal heat exchanger (tube side flow)	MLB/HR	1.48
Design Primary Component Cooling Water flow through one residual heat removal heat exchanger (shell side flow), per heat exchanger	MLB/HR	2.475
Actual Reactor Coolant System flow through one residual heat removal heat exchanger	MLB/HR	1.74
Actual Primary Component Cooling Water flow through one residual heat removal heat exchanger	MLB/HR	1.48
Residual heat removal pump miniflow	MLB/HR	0.00
Design Primary Component Cooling Water flow through one primary component cooling water heat exchanger	MLB/HR	5.85
Design Service Water flow through one primary component cooling water heat exchanger	MLB/HR	3.90
Service Water flow through one primary component cooling water heat exchanger	MLB/HR	3.90
Primary Component Cooling Water flow through one primary component cooling water heat exchanger (two train)	MLB/HR	4.95
Primary Component Cooling Water flow through one primary component cooling water heat exchanger (one train) (Train A / Train B)	MLB/HR	4.28 / 3.91
Auxiliary heat load at cool down start time, two train cooldown	MBTU/HR	50.32
Auxiliary heat load at final time, two train cooldown	MBTU/HR	50.32
Auxiliary heat load at cool down start time, one train cooldown (Train A / Train B)	MBTU/HR	34.46 / 32.12
Auxiliary heat load at final time, one train cooldown (Train A / Train B)	MBTU/HR	34.46 / 32.12
Time cool down starts, hours after reactor shut down	hrs	4
Time corresponding to final auxiliary heat load and Service Water temperature	hrs	20

Note:

1. The BOP Curve is a Residual Decay Heat Standard curve developed by Westinghouse prior to the availability of the ANS-5.1 – 1979 curve. The BOP Curve is conservative for modeling decay heat for Residual Heat Removal cooldown analyses.

TABLE 4.1-1 (continued)
RESIDUAL HEAT REMOVAL COOLDOWN ANALYSIS PARAMETERS FOR SEABROOK STATION SPU

RHRCOOL Input Parameter	Units	Value
Reactor coolant system heat capacity	MBTU/°F	2.01
Reactor coolant pump power	MBTU/HR	20.30
Service Water temperature during cooldown	°F	65
Number of primary component cooling water heat exchangers, two train case	°F	2
Number of residual heat removal heat exchangers, two train case	°F	2
Number of primary component cooling water heat exchangers, single train cases	°F	1
Number of residual heat removal heat exchangers, single train cases	°F	1
Reactor coolant pump stop temperature	°F	160
Reactor Coolant System final temperature (2 train / 1 train)	°F	125 / 200
Primary Component Cooling Water maximum allowable temperature	°F	102
Maximum allowable time Primary Component Cooling Water Temperature is allowed at maximum temperature	hrs	4
Primary Component Cooling Water maximum normal temperature after maximum allowable time at maximum temperature	°F	102
Primary Component Cooling Water heat exchanger type (U-tube or counterflow)		Counterflow
Number of shell passes in residual heat removal heat exchanger		1
Design U for primary component cooling water heat exchanger	BTU/HR/FT^2/°F	351.51

4.2 NSSS/BOP INTERFACE SYSTEMS

4.2.1 INTRODUCTION AND BACKGROUND

As part of the Seabrook Station SPU, the following Balance-of-Plant (BOP) fluid systems were reviewed to assess compliance with Westinghouse Nuclear Steam Supply Systems (NSSS) / Balance-of-Plant interface requirements:

- Main Steam System
- Steam Dump System
- Condensate and Feedwater System
- Emergency Feedwater System
- Steam Generator Blowdown System

The review was performed based on the range of NSSS design parameters specified for an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

4.2.2 INPUT PARAMETERS AND ASSUMPTIONS

A comparison of the SPU parameters (LAR Section 2.0) with the design parameters previously evaluated for systems and components indicates differences that could impact the performance of the BOP systems. For example, an increase in NSSS power from 3425 to 3678 MWt and the upper limit on the average temperature (T_{avg}) (589.1°F) coupled with zero steam generator tube plugging and a 12.4°F increase in feedwater temperature (from the currently analyzed 440.0°F to 452.4°F) would result in about a 9.1% increase in steam/feedwater mass flow rates. Additionally, a feedwater temperature reduction of 50°F (from 440°F to 390°F) coupled with 10% steam generator tube plugging and the approved lower limit on T_{avg} (571°F) would result in a reduction of full-load steam pressure from 1000 psia to 797 psia.

4.2.3 DESCRIPTION OF ANALYSES AND RESULTS

Evaluations of the above BOP systems relative to compliance with Westinghouse NSSS/BOP interface requirements were performed to address the NSSS design parameters for the SPU provided in LAR Section 2.0, which include ranges for parameters such as T_{avg} (571°F to 589.1°F), steam generator tube plugging (0% to 10%) and feedwater temperature (390°F to 452.4°F). These ranges in NSSS design parameters result in ranges of BOP parameters such as steam generator outlet pressure (797 psia to 985 psia) and steam/feedwater mass flow rates (15.07×10^6 lb/hr to 16.54×10^6 lb/hr). The NSSS/BOP interface evaluations were performed to address these NSSS and BOP design parameters. The parameter cases which provide the least amount of margin were selected for the evaluation of individual systems. The results of the NSSS/BOP interface evaluations are delineated below.

4.2.3.1 MAIN STEAM SYSTEM

The following subsections summarize the evaluation of the Main Steam System major components relative to the SPU parameters. The major components of the Main Steam System are the steam generator main steam safety valves, the steam generator power operated atmospheric steam dump valves, and the main steam isolation valves.

4.2.3.1.1 STEAM GENERATOR MAIN STEAM SAFETY VALVES

The setpoints of the main steam safety valves are determined based on the design pressure of the steam generators (1185 psig) and the requirements of the ASME Boiler and Pressure Vessel Code. Since the design pressure of the steam generators has not changed for SPU, there is no need to revise the setpoints of the safety valves.

The main steam safety valves must have sufficient capacity so that main steam pressure does not exceed 110% of the steam generator shell-side design pressure (the maximum pressure allowed by the ASME Boiler and Pressure Vessel Code) for the worst-case loss-of-heat-sink event. Based on this requirement, Westinghouse applies the conservative criterion that the valves should be sized to relieve 105% of the maximum calculated steam flow at an accumulation pressure not exceeding 110% of the main steam system design pressure.

Seabrook Station has twenty main steam safety valves with a total rated capacity of 18.161×10^6 lb/hr, which provides about 109.8% of the maximum SPU full-load steam flow of 16.54×10^6 lb/hr. Therefore, based on the range of NSSS design parameters for the SPU, the capacity of the installed main steam safety valves meets the Westinghouse sizing criterion.

The original design requirements for the main steam safety valves, atmospheric steam dump valves, and steam dump valves included a maximum flow limit per valve of 970,000 lb/hr at 1185 psig. Since the actual capacity of a single main steam safety valve, atmospheric relief valve or steam dump valve is less than the maximum flow limit per valve, the maximum capacity criteria are satisfied.

4.2.3.1.2 STEAM GENERATOR POWER OPERATED ATMOSPHERIC STEAM DUMP VALVES

The atmospheric steam dump valves, which are located upstream of the main steam isolation valves and adjacent to the main steam safety valves, are automatically controlled by steam line pressure during plant operations. The atmospheric steam dump valves 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 atmospheric steam dump valves modulate closed and reseat at a pressure below the opening pressure. The atmospheric steam dump valve set pressure for these operations is between zero-load steam pressure and the setpoint of the lowest-set main steam safety valves. Since there are no changes to these pressures for the

proposed range of NSSS design parameters, there is no need to change the atmospheric steam dump valve setpoint.

The primary function of the atmospheric steam dump valves 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 atmospheric steam dump valves in conjunction with the Emergency Feedwater System permit the plant to be cooled down from the pressure setpoint of the lowest-set main steam safety valves to the point where the Residual Heat Removal System can be placed in service.

During cooldown, the atmospheric steam dump valves are either automatically or manually controlled. In automatic, each atmospheric steam dump valve proportional and integral controller compares steam line pressure to the pressure setpoint, which is manually set by the plant operator.

In the event of a steam generator tube rupture event in conjunction with loss of offsite power, the atmospheric steam dump valves are used to cool down the Reactor Coolant System to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set main steam safety valve. Reactor Coolant System cooldown and depressurization are required to preclude steam generator overfill and to terminate activity release to the atmosphere.

The steam generator atmospheric steam dump valves are sized to have a capacity equal to about 10% of rated steam flow at no-load pressure. This capacity permits a plant cool down to Residual Heat Removal System operating conditions (350°F) in 4 hours (at a rate of about 50°F/hr) assuming cooldown starts 2 hours after reactor shutdown. This design basis is limiting with respect to sizing of the atmospheric steam dump valves and bounds the capacity required for a steam generator tube rupture event.

An evaluation of the installed capacity (2,047,000 lb/hr at 1106.4 psia) indicates that the original design bases in terms of plant cooldown capability can still be achieved for the range of NSSS design parameters for the SPU.

4.2.3.1.3 MAIN STEAM ISOLATION VALVES, AND MAIN STEAM ISOLATION BYPASS VALVES

The main steam isolation valves are located outside the containment and downstream of the main steam safety valves and atmospheric steam dump valves. The valves function to prevent the uncontrolled blowdown of more than one steam generator and to minimize the Reactor Coolant System cooldown and containment pressure to within acceptable limits following a main steam line break. To accomplish this function, the design requirements specify that the main steam isolation valves must be capable of closure within 5 seconds of receipt of a closure signal against steam break flow conditions in either the forward or reverse direction.

Rapid closure of the main steam isolation valves following postulated steam line breaks causes a significant differential pressure across the valve seats and a thrust load on the main steam system piping and piping supports in the area of the main

steam isolation valves. The worst cases for differential pressure increase and thrust loads are controlled by the steam line break area (i.e., 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 impact these variables, the design loads and associated stresses resulting from rapid closure of the main steam isolation valves will not change. Consequently, the SPU has no significant impact on the interface requirements for the main steam isolation valves.

The main steam isolation bypass valves are used to warm up the main steam lines and equalize pressure across the main steam isolation valves prior to opening the main steam isolation valves. The main steam isolation bypass valves perform their function at no-load and low power conditions where the SPU has no significant impact on main steam conditions (e.g., steam flow and steam pressure).

Consequently, the SPU has no significant impact on the interface requirements for the main steam isolation bypass valves.

4.2.3.2 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% power) without reactor trip when subjected to the following load transients:

- Loading at 5% of full power per minute with automatic reactor control.
- Unloading at 5% of full power per minute with automatic reactor control.
- Instantaneous load transients of plus or minus 10% of full power (not exceeding full power) with automatic reactor control.
- Load reductions of 50% 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 piping) be capable of discharging sufficient steam flow at full-load steam pressure to permit the NSSS to withstand an external load reduction of up to 50% of plant rated electrical load without a reactor trip. To prevent a trip, this transient requires the NSSS control systems to be in automatic, including the Reactor Control System, which accommodates 10% of the load reduction. The steam dump capacity should also be sufficient to prevent the main steam safety valves from lifting following a reactor trip from full power.

4.2.3.2.1 STEAM DUMP SYSTEM MAJOR COMPONENTS

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. Thus the limiting case (i.e. lowest steam dump capacity) for the Steam Dump System is Case 4 in LAR Table 2.3-1, which has the lowest steam pressure and highest

steam flow. NSSS operation within the proposed range of design parameters for the SPU will result in a decrease in steam dump capability. An evaluation of this case indicates that steam dump capacity is sufficient to:

- Prevent reactor trip with an external load rejection of 50% of plant rated electrical load, and
- Prevent the main steam safety valves from lifting following a reactor trip from full power.

The NSSS control systems margin to trip analysis (LAR Section 4.3.3) provides an evaluation of the adequacy of the steam dump system in conjunction with the control system set points at SPU conditions. 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 steam generator pressure. These requirements are not impacted by the SPU. Since the steam generator design pressure is not affected by the SPU, the maximum design differential pressure for the steam dump valves remains unchanged. Therefore, the steam dump valves will continue to meet these requirements for the SPU.

4.2.3.3 CONDENSATE AND FEEDWATER SYSTEM

The Condensate and Feedwater System must automatically maintain steam generator water levels during steady-state and transient operations. The major components of the Condensate and Feedwater System are the main feedwater isolation valves, main feedwater control valves and the condensate and feedwater system pumps. Each of these major components is discussed in the sections that follow.

4.2.3.3.1 MAIN FEEDWATER ISOLATION VALVES BACKUP FEEDWATER CONTROL VALVES

The feedwater isolation valves are located outside containment and downstream of the feedwater control valves. The valves function in conjunction with primary isolation signals to the feedwater control valves and backup trip signals to the feedwater pumps 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 Reactor Coolant System cooldowns. To accomplish this function, the feedwater isolation valves and the backup feedwater control valves must be capable of fast closure after receipt of a closure signal under operating and accident conditions. This includes a maximum flow condition with the main feedwater pumps delivering to one steam generator.

The quick-closure requirements imposed on the feedwater isolation valves and the backup feedwater control valves cause 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 the feedwater pumps are in service providing maximum flow following the break. Since these conservative assumptions are not impacted by the SPU, the design loads and associated stresses resulting from rapid closure of these valves will not change.

4.2.3.3.2 FEEDWATER CONTROL VALVES, CONDENSATE AND FEEDWATER SYSTEM PUMPS

The Condensate and Feedwater System available head in conjunction with the feedwater contol valve 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 the secondary system loads. To assure stable feedwater control, with variable speed feedwater pumps, the pressure drop across the feedwater control valves at rated flow (100% power) should be approximately equal to the dynamic losses from the feed pump discharge into the steam generator. These dynamic losses include the frictional resistance of feed piping, high pressure feed water heaters, feed flow meter, and steam generator inlet. To preclude reactor trip following load rejection, adequate margin should be available in the feedwater control valves at full load conditions to permit Condensate and Feedwater System delivery of 103% of rated flow with a 75 psi pressure increase above the full load pressure with the feedwater control valves fully open. LAR Subsection 8.4.3 demonstrates that the feedwater control valves meet this criteria at the SPU conditions.

The current feedwater pump speed control program is set to provide a feedwater control valve pressure drop of about 106.2 psi at full-load and this pressure drop results in a feedwater control valve lift of about 79%. A feedwater control valve lift of about 80% is considered optimum at full load with respect to both valve duty and feedwater control during steady state and transient operation. LAR Subsection 8.4.3 demonstrates that the feedwater control valves meet this criteria at the SPU conditions.

To provide effective control of flow during normal operation, the feedwater control valves are required to stroke open or closed in 20 seconds over the anticipated inlet pressure control range (approximately 0-1600 psig). Additionally, rapid closure of the feedwater control valves is required after receipt of a trip close signal in order to mitigate certain transients and accidents. These requirements are not impacted by the SPU. LAR Section 8.4.3 demonstrates that these stroke time requirements are met at SPU conditions.

4.2.3.4 EMERGENCY FEEDWATER SYSTEM

The Emergency Feedwater System 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. In the latter

function, the Emergency Feedwater System is required to prevent core damage and system overpressurization during transients and accidents, such as a loss of normal feedwater, loss of load, or a secondary system pipe break.

The minimum flow requirements of the Emergency Feedwater System are dictated by accident analyses, and since the SPU impacts these analyses, evaluations of the limiting transients and accidents are performed to confirm that the Emergency Feedwater System performance is acceptable at the SPU conditions. These evaluations are described in LAR Subsections 6.3.2, 6.3.3, and 8.4.4 and show acceptable results.

4.2.3.4.1 EMERGENCY FEEDWATER STORAGE REQUIREMENTS

The emergency feedwater pumps are normally aligned to take suction from the condensate storage tank. To fulfill the Engineered Safety Features 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 condensate storage tank inventory requirements is the loss-of-offsite power transient. The Seabrook Station current licensing basis dictates that in the event of a loss-of-offsite power, sufficient condensate storage tank useable inventory must be available to bring the unit from full power to hot standby conditions, maintain the plant at hot standby for 4 hours, and then cooldown the Reactor Coolant System to the residual heat removal system cut-in temperature (350°F) in 5 hrs.

Since the required condensate storage tank inventory is a function of plant rated power and other NSSS design parameters, a new analysis was performed as part of the BOP evaluations to determine required inventory for the range of NSSS design parameters for the SPU. This analysis is based on the following conservative assumptions:

- Reactor trip occurs from 100% of the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) from a low low water level in the steam generators. A two second delay is assumed before reactor trip following loss of offsite power.
- Steam is released from the steam generators at the first safety valve set point plus accumulation plus setting tolerance for drift.
- Steam generator level is restored and maintained well above the level set point (26% of wide range span) that requires initiation of primary side feed and bleed operation.
- The condensate storage tank operating fluid temperature is at the maximum allowable value (100°F).

The analysis concluded that a minimum usable inventory of 196,000 gallons meets the plant licensing bases for the range of NSSS design parameters for the SPU and permits level in the steam generators to be restored and maintained at 58% of wide range span. Therefore, no change is required to the plant technical specification limit

on condensate storage tank contained volume of 212,000 gallons for operation within the approved range of NSSS design parameters.

4.2.3.5 STEAM GENERATOR BLOWDOWN SYSTEM

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

The Steam Generator Blowdown System 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 tied to allowable condenser in-leakage, total dissolved solids in the Seabrook Station feedwater, and the allowable primary to secondary leakage. Since these variables are not impacted by the SPU, the blowdown required to control secondary chemistry and steam generator solids will not be impacted by the SPU.

4.2.4 CONCLUSIONS

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

4.2.4.1 MAIN STEAM SYSTEM

- The capacity of the installed main steam safety valves is adequate to meet the original sizing bases for the range of SPU NSSS design parameters.
- The capacity of the installed atmospheric steam dump valves is adequate to meet the original sizing for the range of SPU NSSS design parameters.
- SPU does not adversely impact the main steam isolation valves and main steam isolation bypass valves.

4.2.4.2 STEAM DUMP SYSTEM

An evaluation of the steam dump system for the limiting case indicates that there is sufficient capacity to:

- Prevent reactor trip with an external load rejection of 50% of plant rated electrical load, and
- Prevent the main steam safety valves from lifting following a reactor trip.

4.2.4.3 CONDENSATE AND FEEDWATER SYSTEM

- The design loads and associated stresses resulting from rapid closure of the feedwater isolation valves are not impacted by the SPU.

- The feedwater control valves have adequate margin at SPU conditions to permit condensate and feedwater delivery of 96% of rated flow with a 100 psi pressure increase above the full load pressure with the feedwater control valves fully open.
- The feedwater control valve lift during steady state and transient operating conditions at SPU is considered optimal.
- The feedwater control valves will continue to meet their stroke time requirement following the SPU.

4.2.4.4 EMERGENCY FEEDWATER SYSTEM

- The minimum flow requirements of the Emergency Feedwater System are acceptable for the SPU.
- The condensate storage tank minimum useable volume of 196,000 gallons is sufficient to meet the plant licensing bases for the range of NSSS design parameters for the SPU. Therefore, no change is required to the plant technical specification limit on condensate storage tank contained volume of 212,000 gallons for operation within the approved range of NSSS design parameters.

4.2.4.5 STEAM GENERATOR BLOWDOWN SYSTEM

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

4.3 INSTRUMENTATION AND CONTROLS

4.3.1 REACTOR PROTECTION SYSTEM / ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

The impact of the Seabrook Station SPU on the Reactor Protection System and the Engineered Safeguards Features Actuation System is limited to several changes to setpoints. These Reactor Protection System and the Engineered Safeguards Features Actuation System setpoint changes are summarized in LAR Subsection 4.3.2. This section also discusses initial condition uncertainties applied to nominal parameter values for use in the safety analyses. The applicable General Design Criteria for the Reactor Protection System and the Engineered Safeguards Features Actuation System are 1, 4, 13, 19, 20, 21, 22, 23, and 24. Compliance with the General Design Criteria is not affected by the SPU.

4.3.2 SETPOINT UNCERTAINTY ANALYSIS

For the Seabrook Station SPU, the instrument uncertainties that would be affected by SPU conditions were evaluated. These fall into two categories: Initial Condition Uncertainties and Reactor Trip and Emergency Safety Feature Actuation System Setpoint Uncertainties. The following describes the evaluation of each category.

4.3.2.1 INITIAL CONDITION UNCERTAINTIES

4.3.2.1.1 INTRODUCTION

Initial condition uncertainties are conservative steady state instrumentation measurement uncertainties that are applied to nominal parameter values in order to obtain conservative initial conditions for use in safety analyses. The initial condition uncertainties affected by the SPU were recalculated at SPU conditions for use in the Seabrook Station SPU analyses and/or evaluations to assess the acceptability of the safety analyses at SPU conditions. The initial condition uncertainties for SPU conditions were provided as input to the loss of coolant accident (LOCA) analysis, non-LOCA analysis, steam generator tube rupture analysis, LOCA mass and energy release analysis, main steamline break mass and energy release analysis, LOCA hydraulic forces analysis, and core thermal-hydraulic design analysis.

4.3.2.1.2 INPUT PARAMETERS AND ASSUMPTIONS

The uncertainty calculations for the Seabrook Station were performed for the SPU operating conditions based on the plant-specific instrumentation and plant calibration and calorimetric procedures.

4.3.2.1.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The uncertainty analysis statistically combines the statistically independent uncertainty components or groups of components of an instrument channel. Those uncertainties that are not independent are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined.

Initial condition uncertainties were evaluated and recalculated as appropriate for the following three parameters that are affected by the SPU. Note: The analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) includes calorimetric uncertainties.

- Reactor Coolant System T_{avg} Control - Automatic reactor control system
- Reactor Power - Daily calorimetric power measurement
- Steam generator water level control system

4.3.2.1.4 ACCEPTANCE CRITERIA AND RESULTS

The acceptance criterion for the initial condition uncertainties are that the final calculated values must be bounded by the values assumed in the safety analyses.

The results of the initial condition uncertainty analysis for the Seabrook Station SPU are summarized in LAR Table 4.3-1 along with the allowances incorporated in the safety analyses. (Note: Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.) This table demonstrates that the safety analyses incorporate uncertainties which are equal to or greater than the final calculated values. The uncertainty calculations for Steam Generator Water Level Control included consideration of the generic Steam Generator level uncertainty issues [References 4.3-1, 4.3-2, 4.3-3, and 4.3-4], which are unrelated to the SPU.

4.3.2.1.5 CONCLUSIONS

Initial condition uncertainties were determined for the Seabrook Station SPU conditions and were provided as input to the safety analyses and/or evaluations. Final initial condition uncertainties were calculated and confirmed to be bounded by the analysis initial condition uncertainties.

4.3.2.2 REACTOR TRIP SYSTEM/ENGINEERED SAFETY FEATURE ACTUATION SYSTEM SETPOINT UNCERTAINTIES

4.3.2.2.1 INTRODUCTION

The Reactor Trip System / Engineered Safety Feature Actuation System nominal trip setpoints and Technical Specification allowable values have been reviewed for operation at the SPU conditions. As a result of this review, the necessary nominal trip setpoints and allowable value changes have been identified.

4.3.2.2.2 DESCRIPTION OF ANALYSES AND EVALUATIONS

The uncertainty analysis statistically combines the statistically independent uncertainty components or groups of components of an instrument channel. 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 Reactor Trip System / Engineered Safety Feature Actuation System uncertainty calculations were evaluated based on operation at the SPU conditions, along with

the plant-specific instrumentation and plant calibration procedures, and revisions to the safety analysis limits values that were required to support operation at the SPU conditions.

4.3.2.2.3 ACCEPTANCE CRITERIA AND RESULTS

The setpoint methodology defines the Total Allowance as the difference between the limiting UFSAR safety analysis limits and the nominal trip setpoints. The Channel Statistical Allowance is the statistical combination of the instrument channel uncertainty components. Margin is defined as the difference between the Total Allowance and the Channel Statistical Allowance. The acceptance criterion for the Reactor Trip System / Engineered Safety Feature Actuation System setpoints is that margin is greater than or equal to zero.

Setpoint calculations were performed for the affected Reactor Trip System / Engineered Safety Feature Actuation System parameters. LAR Table 4.3-2 summarizes the most limiting safety analysis limits, nominal trip setpoints, and Technical Specification allowable values for the parameters that were affected by the Seabrook Station SPU. Incorporation of these allowable values and nominal trip setpoints changes will support operation at SPU conditions in a manner consistent with the UFSAR assumptions. Functions not listed in LAR Table 4.3-2 are not affected by the Seabrook Station SPU. The Steam Generator Water Level uncertainty calculations included consideration of the generic uncertainty issues [References 4.3-1, 4.3-2, 4.3-3, and 4.3-4], which are unrelated to the SPU.

4.3.2.2.4 CONCLUSIONS

With the setpoint and allowable value changes as shown in LAR Table 4.3-2, the Reactor Trip System / Engineered Safety Feature Actuation System functions have acceptable margins and therefore are acceptable for operation at the SPU conditions.

4.3.3 CONTROL SYSTEMS

The NSSS control systems have been evaluated to determine the impact of the SPU. The evaluation has been performed and documented in two basic areas:

- Pressurizer Control Component Sizing
- Margin to Trip Assessment.

The Pressurizer Control Component Sizing specifically evaluates the impact of the SPU upon the pressurizer power operated relief valves, the pressurizer spray valves, the pressurizer heaters, and the steam dump valves.

The Margin to Trip Assessment specifically evaluates the various NSSS Control Systems to ensure that a stable and acceptable condition is obtained in response to normal (American Nuclear Society Condition I) operating transients at the SPU conditions. The specific NSSS control systems evaluated include the rod control system, the steam dump control system, the pressurizer pressure control system, and the T_{avg} control system. Also evaluated as part of this assessment are certain

Reactor Protection System / Engineered Safety Features Actuation System setpoints which include: Overtemperature ΔT, Overpower ΔT, Low-low steam generator water level, and High-high steam generator water level. The applicable General Design Criteria for the control systems are 1, 13, 19, and 24.

4.3.3.1 PRESSURE CONTROL COMPONENT SIZING

The NSSS pressure control components were evaluated for the SPU conditions, including a reactor vessel average temperature (T_{avg}) range of 571°F to 589.1°F. The SPU conditions, shown in LAR Section 2.0, are different from those assumed in the original sizing calculation of the NSSS pressure components. Therefore, the installed capacities of the following NSSS pressure components are evaluated at the SPU conditions.

- Pressurizer power operated relief valves
- Pressurizer spray valves
- Pressurizer heaters
- Steam dump valves

The adequacy of installed capacities of the pressurizer and steam generator safety valves at the SPU conditions is confirmed by the appropriate safety analyses in LAR Section 6.3.

4.3.3.1.1 PRESSURIZER POWER OPERATED RELIEF VALVES

The original sizing basis analysis for the pressurizer power operated relief valves was performed at the SPU conditions. The results showed that the original sizing basis criteria for the pressurizer power operated relief valves are met. Therefore the installed capacity of the pressurizer power operated relief valve is adequate at the SPU conditions.

4.3.3.1.2 PRESSURIZER SPRAY VALVES

The sizing basis for the pressurizer spray valves is to prevent challenging the pressurizer power operated relief valves for a 10% step load decrease transient. For a load decrease up to 10% power, the spray valves are the sole means of providing pressure control without actuating the pressurizer power operated relief valve in the automatic mode of pressure control.

An analysis was performed for the design basis 10% step load decrease transient at SPU conditions. The analysis results showed a maximum peak pressurizer pressure of 2339 psia. The peak pressure remains below the pressurizer power operated relief valve actuation setpoint of 2400 psia, therefore, the pressurizer power operated relief valve will not be challenged for a design basis 10% step load decrease transient.

The installed total pressurizer spray valves capacity of no less than 900 gpm is adequate at the SPU conditions.

4.3.3.1.3 PRESSURIZER HEATERS

The pressurizer heaters total capacity is proportional to the pressurizer volume. For Westinghouse plants, the required capacity for pressurizer heaters is one kW/cubic foot of pressurizer total volume. Since the total pressurizer volume is not changed by the SPU, the pressurizer heater capacity remains acceptable.

4.3.3.1.4 STEAM DUMP VALVES

The steam dump valves are designed to act as an artificial heat sink during large (50%) load rejections and to provide a means of relieving the stored energy and decay heat after a reactor trip. The main requirement for their capacity is that they be able to relieve sufficient steam to prevent an automatic reactor trip following a large load rejection. Other secondary requirements are to avoid steam generator safety valve lifting following either a large load rejection or a reactor trip from full power transient.

An analysis was performed for the design basis 50% load rejection transient and the reactor trip transient at the SPU conditions. The analysis results showed that there was no automatic reactor trip during and following the design basis 50% load rejection transient for both high and low T_{avg} conditions. The minimum margins to overtemperature ΔT and overpower ΔT trip setpoints available were 5.0% nominal ΔT and 9.6% nominal ΔT respectively. The pressurizer power operated relief valves were also not challenged. The maximum peak steam generator pressure was 1118 psia, which is below the lowest set pressure for the steam generator safety valves (1200 psia).

The sizing criteria for the steam dump valves are met at the SPU conditions. The results showed no automatic reactor trip following a design basis 50% load rejection and no lifting of the steam generator safety valves following a reactor trip from full power transient. The total installed steam dump capacity is adequate at the SPU conditions.

4.3.3.1.5 CONCLUSIONS

The NSSS pressure control components were evaluated at the maximum analyzed power conditions, including a T_{avg} range from 571.0°F to 589.1°F. The following pressure control components were determined to have adequate installed capacity at the SPU conditions:

- Pressurizer power operated relief valves
- Pressurizer spray valves
- Pressurizer heaters
- Steam dump valves

By meeting these design bases, the pressure control components meet the requirements of General Design Criteria 1, 13, 19, and 24.

4.3.3.2 MARGIN TO TRIP ANALYSIS

4.3.3.2.1 INTRODUCTION

The NSSS Control Systems are designed to provide a stable and acceptable response to normal American Nuclear Society Condition I operating transients. The Seabrook SPU conditions include a full power T_{avg} window of 571.0°F to 589.1°F. To address this change, the steam dump control system setpoints and the pressurizer level control program were revised. There were no other NSSS control system setpoint changes required for the SPU. Therefore, the impact of these changes on the NSSS control systems for the SPU was evaluated. Also, the following reactor protection systems and Engineered Safety Features Actuation System setpoints were revised:

- Overtemperature ΔT trip
- Low-low steam generator level trip
- Overpower ΔT trip
- High-high steam generator level Engineered Safety Features Actuation System

The above revised reactor protection system setpoints were also evaluated to determine the impact on the plant operating margin. The permissive P-9 current setpoint was evaluated for its continued applicability at SPU conditions. (Note: The P-9 permissive setpoint is defined as a percentage of licensed thermal power, below which a direct reactor trip signal is not generated upon a turbine trip initiation; the P-9 is currently set at 20% for Seabrook Station.) This section summarizes the control system American Nuclear Society Condition I transient analyses performed for the SPU and the associated evaluation results.

4.3.3.2.2 METHOD OF ANALYSIS/EVALUATION

To ensure that the revised and the current NSSS control systems setpoints will provide acceptable plant response and adequate plant operating margins at the SPU power conditions, the following limiting NSSS control systems design basis American Nuclear Society Condition I transients were analyzed. These transients were analyzed at the SPU conditions using the LOFTRAN computer code.

- 50% load rejection
- 5%/minute ramp load changes
- 10% step load changes
- Turbine trip without reactor trip from P-9 setpoint

The major analysis assumptions are as follows.

- Analyses for both low (571.0°F) and high (589.1°F) Reactor Coolant System full power T_{avg} and 0% and 10% average steam generator tube plugging conditions.

- Credit for the NSSS control systems (rod control, steam dump control, and pressurizer pressure control) in automatic mode of control.
- For P-9 setpoint analysis, no credit for the rod control system but credit for steam dump and pressurizer pressure control systems.
- No credit for pressurizer and steam generator safety valves.
- Best estimate fuel reactivity feedbacks (moderator temperature coefficient, Doppler power defect and control rod worth) at beginning of life core conditions, which are limiting for the margin to trip assessment.
- No credit for operator action.

4.3.3.2.3 ACCEPTANCE CRITERIA

The plant parameter responses should be stable during and following the American Nuclear Society Condition I transients.

Acceptable reactor trip and Engineered Safety Features Actuation System setpoints and time constants should provide adequate margins to the technical specifications nominal trip setpoints at steady-state conditions and during and following the design basis American Nuclear Society Condition I (normal operating) transients.

With the NSSS control systems assumed operational, a turbine trip without a direct reactor trip below the P-9 setpoint will not challenge the pressurizer power operated relief valves. For Seabrook Station this criterion applies with the NSSS rod control system in manual mode of operation.

4.3.3.2.4 RESULTS

The results showed stable plant response during and following the American Nuclear Society Condition I transients. The results of this evaluation also showed that the proposed average T_{avg} NSSS control systems control scheme will provide acceptable plant response to American Nuclear Society Condition I transients.

The revised reactor trip overtemperature ΔT and overpower ΔT setpoints were evaluated to assess the plant operability margins during and following the American Nuclear Society Condition I transients at SPU conditions. The steady-state and transient margins to overtemperature ΔT and overpower ΔT were also evaluated. The results showed adequate operating margins exist for these setpoints at steady-state and during and following a 50% load rejection transient. The operating margin to the low-low steam generator level reactor trip setpoint is also adequate. Other reactor trips that could be challenged by American Nuclear Society Condition I transients at SPU conditions (i.e., high power range flux, pressurizer low pressure, pressurizer high level) were included in the American Nuclear Society Condition I transient analyses. Evaluation of the analyses results of 5% per minute, 10% step increase, and 50% load transients confirmed that plant operating margins to these reactor trip setpoints are adequate at SPU conditions. The 10% step load decrease transient is described in LAR Subsection 4.3.3.1.2.

The revised high high steam generator level Engineered Safety Features Actuation System setpoint was evaluated and is acceptable. The margins to certain other Engineered Safety Features Actuation System setpoints (e.g., pressurizer low pressure and steam line low pressure) are limiting at low T_{avg} (i.e., full power vessel average temperature of 571°F) operation. These Engineered Safety Features Actuation System setpoints were also evaluated using the results of the American Nuclear Society Condition I transients analyses at SPU conditions. Results showed adequate margin to these Engineered Safety Features Actuation System actuation setpoints.

The permissive P-9 setpoint analysis showed that a turbine trip without a reactor trip from the current P-9 setpoint will not result in challenging the pressurizer power operated relief valve nor actuate a reactor trip.

4.3.3.2.5 CONCLUSIONS

The revised control systems setpoints will provide stable control system responses during and following American Nuclear Society Condition I operational transients.

The revised overtemperature ΔT, overpower ΔT, low-low steam generator level reactor trip setpoints and the high high steam generator level Engineered Safety Features Actuation System setpoints are acceptable at SPU conditions. The current P-9 setpoint is acceptable at SPU conditions as well. By meeting these design bases, the control systems meet the requirements of General Design Criteria 1, 13, 19, and 24.

4.3.4 COLD OVERPRESSURE MITIGATION SYSTEM

4.3.4.1 INTRODUCTION AND BACKGROUND

The Cold Overpressure Mitigation System provides Reactor Coolant System pressure relief capability during relatively low temperature operation (i.e., Reactor Coolant System temperature less than about 350°F). Two pressurizer power operated relief valves are used to provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the Reactor Coolant System pressure from exceeding the pressure and temperature limits of 10 CFR 50, Appendix G. The design basis mass and heat injections transients and the current Cold Overpressure Mitigation System power operated relief valve setpoints for Seabrook Station are defined in the Technical Specifications.

4.3.4.2 INPUT PARAMETERS AND ASSUMPTIONS

The only input parameter change to the Cold Overpressure Mitigation System analysis due to the SPU is an increase in the nominal core full power condition to 3659 MWt. The nominal full power conditions for the SPU are presented in LAR Section 2.0.

4.3.4.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

Cold Overpressure Mitigation System mass and heat injections analyses are performed at reactor shutdown and Reactor Coolant System cold conditions (i.e., Reactor Coolant System temperature ≤ 350°F). Therefore, the SPU does not affect the Cold Overpressure Mitigation System power operated relief valve setpoint determination. The critical parameters for Cold Overpressure Mitigation System power operated relief valve setpoint determination are:

- The design basis mass and heat injections transients,
- Reactor Coolant System volumes,
- Pressurizer power operated relief valve characteristics,
- Wide range pressure/temperature uncertainties, and
- Pressure temperature limits of 10 CFR 50, Appendix G and other constraints.

The impact of the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) on these parameters is discussed below.

The design basis mass and heat injection transients have not changed for the SPU. The nominal full power conditions for the SPU, as presented in LAR Section 2.0 include a maximum average tube plugging level of 10%. The Reactor Coolant System volume will be slightly reduced (less than 1%) due to the 10% steam generator tube plugging conditions. A reduction in 1% Reactor Coolant System volume will have no noticeable effect on the Cold Overpressure Mitigation System mass and heat injections analyses.

The pressurizer power operated relief valve characteristics, the power operated relief valve discharge flow rate and the wide range pressure/temperature uncertainties have not changed for the SPU. Furthermore, the heatup and the cooldown limits for 20 Effective Full Power Years will remain valid at the SPU conditions (see LAR Subsection 5.1.3).

As presented in LAR Section 2.0, a full power reactor vessel average temperature (T_{avg}) window between 571.0°F and 589.1°F is included in the SPU. The nominal full power T_{avg} does not affect the Cold Overpressure Mitigation System analysis. Therefore, the T_{avg} window of 571°F and 589.1°F for the SPU will not affect the Cold Overpressure Mitigation System mass and heat injections analyses and the Cold Overpressure Mitigation System power operated relief valve setpoints.

4.3.4.4 ACCEPTANCE CRITERIA AND RESULTS

The acceptance criteria for the Cold Overpressure Mitigation System analysis is that the Cold Overpressure Mitigation System power operated relief valve setpoints should prevent the Reactor Coolant System pressure from exceeding the pressure and temperature limits of 10 CFR 50, Appendix G for the design basis mass and heat injections transients. The applicable General Design Criteria are 15 and 31.

Based on the above assessment of the impact of SPU on Cold Overpressure Mitigation System, the SPU will not affect the Cold Overpressure Mitigation System mass and heat injections analyses and the Cold Overpressure Mitigation System power operated relief valve setpoints.

4.3.4.5 CONCLUSIONS

The analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) does not impact the Cold Overpressure Mitigation System power operated relief valve setpoints. Since the Cold Overpressure Mitigation System is not affected by the SPU, General Design Criteria 15 and 31 continue to be met. Therefore, Cold Overpressure Mitigation System is acceptable at the SPU condition.

TABLE 4.3-1
SEABROOK STATION SPU SUMMARY OF INITIAL CONDITION UNCERTAINTIES

Parameter	Limiting Analysis Initial Condition Uncertainties[1]	Calculated Final Initial Condition Uncertainties[1]
Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017		

TABLE 4.3-2
SEABROOK STATION SPU SUMMARY OF
REACTOR TRIP SYSTEM / ENGINEREED SAFETY FEATURE ACTUATION SYSTEM
SETPOINT CALCULATIONS

Protection Function	Nominal Trip Setpoint	Safety Analysis Limit Value	Tech. Spec Allowable Value
Overtemperature ΔT Reactor Trip			
K1 max	N/A	1.34	N/A
K1 nominal	≤1.21	N/A	(Note 1)
K2	0.021 /°F	0.021 /°F	N/A
K3	0.0011 /psi	0.0011 /psi	N/A
f(ΔI) function between (-30% and +8%)	0	0	N/A
positive slope (ΔI>8%)	1.71 % Rated Thermal Power / % ΔI	1.71 % Rated Thermal Power / % ΔI	N/A
negative slope (ΔI<-30%)	2.87 % Rated Thermal Power / % ΔI	2.87 % Rated Thermal Power / % ΔI	N/A
Overpower ΔT Reactor Trip			
K4 max	N/A	1.176	N/A
K4 nominal	≤1.116	N/A	(Note 2)
K5	0.02 /°F	0.02 /°F	N/A
K6	0.00175 /°F	0.00175 /°F	N/A
Steam Generator Water Level - Low Low Reactor Trip	≥20% span	0% span	≥19.5% span
Steam Generator Water Level - High-High Turbine Trip / Feedwater Isolation	≤90.8% span	97.7% span (Note 3)	≤91.3% span

Notes:

(1) Note that 0.5% of ΔT span is applicable to the OTΔT input channels ΔT, T_{avg} and Pressurizer Pressure; 0.25% of ΔT span is applicable to ΔI.

(2) Note that 0.5% of ΔT span is applicable to the OTΔT input channels ΔT and T_{avg}.

(3) Based on Maximum Reliable Indicated Limit (MRIL.)

4.4 REFERENCES

4.3-1 NSAL-02-03, Rev. 1, "Steam Generator Mid-deck Plate Pressure Loss Issue," April 2002.

4.3-2 NSAL-02-04, Rev. 0, "Maximum Reliable Indicated Steam Generator Water Level," February 2002.

4.3-3 NSAL-02-05, Rev. 1, "Steam Generator Water Level Control System Uncertainty Issue," April 2002.

4.3-4 NSAL-03-09, Rev. 0, "Steam Generator Water Level Uncertainties," September 2003.

SEABROOK STATION

SECTION 5.0

NSSS COMPONENTS

5.0 NUCLEAR STEAM SUPPLY SYSTEM COMPONENTS

Evaluations were performed for the Nuclear Steam Supply System (NSSS) components to determine the stress and fatigue usage effects of operation at the SPU conditions through the remaining Seabrook Station facility operating license. The design specifications, engineering calculations, design reports, and other technical documentation were evaluated with respect to the SPU.

5.1 REACTOR PRESSURE VESSEL

5.1.1 REACTOR PRESSURE VESSEL STRUCTURAL EVALUATION

5.1.1.1 INTRODUCTION AND BACKGROUND

An addendum to the reactor pressure vessel structural report was prepared and used to evaluate the stress and fatigue effects of the revised operating parameters and Reactor Coolant System transients associated with the Seabrook Station SPU at the analyzed SPU core power level of 3659 (3678 MWt NSSS power level). The structural report addendum evaluates the maximum primary plus secondary stress intensity ranges and the maximum cumulative fatigue usage factors resulting from the revised operating parameters and transients. The resulting calculated stress intensity range and usage factor values are compared with the applicable limits of Section III of the ASME Boiler and Pressure Vessel Code [Reference 5.1-1]. The reactor pressure vessel stress report along with this addendum affirms that operation of the reactor pressure vessel in accordance with the conditions associated with the SPU, the original design basis, or combination thereof, does not result in stress intensities nor fatigue usage factors which exceed the acceptance criteria of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with Addenda through the Winter of 1972.

5.1.1.2 INPUT PARAMETERS AND ASSUMPTIONS

Presented in the structural report and addendum are the analyses and evaluations necessary per Section III of the ASME Boiler and Pressure Vessel Code to substantiate the structural adequacy of the Seabrook Station reactor pressure vessel for operation in accordance with the SPU. The analyses and evaluations in this addendum incorporate into the reactor pressure vessel stress report revised operating temperatures, revised Reactor Coolant System transients and revised seismic and loss of coolant accident reactor vessel/internals interface loads associated with the SPU. Revised maximum stress intensity ranges and cumulative fatigue usage factors are calculated. The results demonstrate that the reactor pressure vessel continue to satisfy the design requirements defined in the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with Addenda through the Winter of 1972 [Reference 5.1-1].

5.1.1.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The revised Reactor Coolant System design transients for the Seabrook Station SPU from the design transient review were compared to the original design basis transients from the original equipment specification. This transient review determines which revised transients are more severe than the original design transient by comparing rates, magnitudes and durations of the transient temperature variations as well as the magnitudes of the pressure variations. Based on this review, it was determined which revised transients must be considered in the stress evaluations.

Seismic and loss of coolant accident reactor vessel/internals interface loads for the SPU were reviewed for the reactor pressure vessel and vessel-barrel flange (horizontal and vertical), vessel-upper support plate flange (horizontal and vertical), barrel outlet nozzle, and lower radial keys. A comparison of these loads and the allowable loads defined the basis for the reactor pressure vessel evaluation.

The outlet nozzle regions of the reactor pressure vessel pressure boundary are the only regions considered to be in contact with reactor coolant at vessel outlet temperature (T_{hot}) during normal plant operation. These are evaluated for the effects of the T_{hot} range . The balance of the reactor pressure vessel including the head flange, vessel flange, closure studs, bottom head to shell juncture, vessel wall transition, inlet nozzle, control rod drive mechanism housings, bottom head instrument tubes, core support lugs, and head adapter plugs are affected by the vessel inlet temperature. Therefore, the T_{cold} range for the SPU transient is applied to these regions.

The peak stress intensities for the fatigue evaluation were also adjusted to account for the incremental thermal stresses for the revised Reactor Coolant System transients. The stresses were multiplied by the appropriate stress concentration factors, where necessary, before superimposing them onto the alternating stresses from the original stress report. The allowable cycles of the alternating stresses were found from the applicable fatigue curve and the cumulative usage factors were revised accordingly.

Where applicable, the maximum and minimum stress intensity ranges and fatigue usage factors were revised to reflect the changes in the transients due to the SPU for various regions. In other cases, the original design basis stress analysis in the original stress report remains conservative and new calculations were not necessary.

5.1.1.4 ACCEPTANCE CRITERIA

The maximum range of primary plus secondary stress intensity resulting from normal and upset condition design transient mechanical and thermal loads shall not exceed $3S_m$ at operating temperature. The maximum cumulative usage factor resulting from the peak stress intensities due to the normal and upset condition design transient mechanical and thermal loads shall not exceed 1.0 in accordance with the procedure outlined in Paragraph NB-3222.4 of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with Addenda through the Winter of 1972. The

reactor pressure vessel meets the requirements of General Design Criteria 1, 4, 14, and 31.

5.1.1.5 RESULTS

The maximum ranges of stress intensity and maximum cumulative fatigue usage factors from the reactor vessel evaluation are summarized in LAR Table 5.1-1. The maximum ranges of stress intensity at the limiting locations remained unchanged as a result of the Seabrook Station SPU. Additionally, most of the other vessel regions had fatigue usage factors which remained unchanged. The regions which had increases in the maximum fatigue usage factors are the inlet nozzles, outlet nozzles, outlet nozzle support pads, and core support lugs. The seismic and loss of coolant accident loads are summarized in LAR Table 5.1-2. The loads are less than allowable loads.

Based upon the results, the stress intensity and fatigue usage factor limits of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with Addenda through the Winter of 1972 are satisfied. Therefore, the Seabrook Station SPU is acceptable from the standpoint of the reactor pressure vessel design.

5.1.1.6 CONCLUSIONS

Based upon the reactor pressure vessel evaluation, the maximum ranges of primary plus secondary stress intensity and maximum cumulative fatigue usage factors for the Seabrook Station reactor pressure vessel continue to satisfy the applicable limits of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition with addenda through the Winter 1972 Addenda. The reactor vessel/internals interface loads are below the allowable limits. The revised operating parameters, design transients, and design loads associated with the Seabrook Station SPU are justified for application to the reactor vessel. The reactor pressure vessel structural evaluation concludes that the acceptance criteria continue to be met for the SPU, including General Design Criteria 1, 4, 14, and 31.

5.1.2 REACTOR PRESSURE VESSEL NEUTRON FLUENCE EVALUATION

5.1.2.1 INTRODUCTION

In the assessment of the state of embrittlement of light water reactor pressure vessels, an accurate evaluation of the neutron exposure of the materials comprising the beltline region of the vessel is required. This exposure evaluation must, in general, include assessments not only at locations of maximum exposure at the inner radius of the vessel, but also as a function of axial, azimuthal, and radial location throughout the vessel wall.

In order to satisfy the requirements of 10 CFR 50, Appendix G [Reference 5.1-2], for the calculation of pressure/temperature limit curves for normal heatup and cooldown of the Reactor Coolant System, fast neutron exposure levels must be defined at depths within the reactor pressure vessel wall equal to 25 and 75 percent of the wall thickness for each of the materials comprising the beltline region. These locations

are commonly referred to as the 1/4T and 3/4T positions in the reactor pressure vessel wall. The 1/4T exposure levels are also used in the determination of upper shelf fracture toughness as specified in 10 CFR 50, Appendix G. To determine the values of pressurized thermal shock reference temperature for comparison with the applicable pressurized thermal shock screening criterion as defined in 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," [Reference 5.1-3] maximum neutron exposure levels experienced by each of the beltline materials are required. These maximum levels occur at the vessel inner radius.

The methodology used to determine the fast (E > 1.0 MeV) neutron exposure of the Seabrook Station reactor pressure vessel is derived from the guidance provided in ASTM Standard E853, "Analysis and Interpretation of Light Water Reactor Surveillance Results," and Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," [Reference 5.1-4]. The analytical methodology has received regulatory approval as documented in WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and Reactor Coolant System Heatup and Cooldown Curves," [Reference 5.1-5]. The Westinghouse methodology has also been documented in WCAP-15557 (non-Proprietary), "Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology," [Reference 5.1-6].

5.1.2.2 DESCRIPTION OF ANALYSIS / EVALUATION AND INPUT ASSUMPTIONS

A three-dimensional assessment of fast (E > 1.0 MeV) neutron exposures for the Seabrook Station reactor geometry was made using discrete ordinates transport techniques. The analysis was based on a 2D/1D synthesis of neutron fluxes that were obtained from a series of plant- and cycle-specific forward transport calculations using R-Θ, R-Z, and R spatial mesh. These transport calculations were subsequently compared against dosimetry results obtained from the in-vessel surveillance capsules withdrawn to date at Seabrook Station in order to demonstrate that the plant-specific analysis meets the 20% uncertainty criterion specified in Regulatory Guide 1.190; however, these comparisons only serve to validate the calculational model and are not used in any way to modify the calculational results.

The core power distributions used in the plant-specific analysis were taken from the nuclear design reports for each of the first nine operating fuel cycles at Seabrook Station, where Cycle 9 was assumed to shutdown at nominal end-of-cycle full power capability. Future projections were then based on the preliminary Cycle 10 (current cycle) core loading pattern at operating conditions, followed by the worst case loading pattern that produced the highest flux on the vessel wall from preliminary Cycle 11-13 core designs at SPU operating conditions. The worst case loading pattern of the three preliminary SPU core designs was determined to be Cycle 12, which was the core design utilized for the projections beyond Cycle 10.

5.1.2.3 ACCEPTANCE CRITERIA

Adequacy of the modeling is tested by comparing the calculated results against dosimetry measurements from surveillance capsules withdrawn from the Seabrook Station reactor pressure vessel. As long as these comparisons fall within the ± 20% criterion specified in Regulatory Guide 1.190, the calculational results are validated; i.e., no specific acceptance criterion applies to the calculated values. However, these calculated results are used as input to reactor pressure vessel analysis that is described in LAR Subsection 5.1.3.

5.1.2.4 RESULTS

Comparisons were made of the measurement results from the in-vessel surveillance capsules withdrawn from the Seabrook Station reactor pressure vessel versus the corresponding calculated predictions obtained at the measurement locations for the fast (E > 1.0 MeV) neutron sensor reactions. An examination of the measurement/calculation ratios of the fast neutron sensor reaction rates obtained from the surveillance capsule irradiations shows consistent behavior for the reactions at all capsule locations within the constraint of the allowable ± 20% (1σ) uncertainty in the final calculated results. The average measurement/calculation ratios range from 1.00 to 1.07 for the individual capsules and that the overall average measurement/calculation ratio for the entire foil data set is 1.03 with an associated sample standard deviation of 12.4%. Therefore, these comparisons of calculations with the surveillance capsule dosimetry sets withdrawn to date validate the neutron transport calculations performed to support this program and demonstrate that the uncertainty criterion of ± 20% (1σ), as specified by Regulatory Guide 1.190, has been satisfied for the Seabrook Station reactor.

Based on the current NRC position of using the calculated values of neutron fluence to specify the neutron exposure for use in materials damage correlations, the calculated exposure values were provided for use in the materials properties assessments of the Seabrook Station reactor pressure vessel at SPU conditions.

5.1.2.5 CONCLUSIONS

The calculated maximum reactor pressure vessel neutron exposures were provided as input to the reactor pressure vessel integrity evaluation described in LAR Subsection 5.1.3.

5.1.3 REACTOR PRESSURE VESSEL INTEGRITY – NEUTRON IRRADIATION

5.1.3.1 INTRODUCTION

Reactor pressure vessel integrity is affected by any changes in plant parameters that affect neutron fluence levels or temperature/pressure transients. The neutron fluence increase resulting from the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) has been evaluated to determine the potential effect

on reactor pressure vessel integrity. The reactor pressure vessel integrity evaluation for the SPU included the following:

- Review of the reactor pressure vessel surveillance capsule removal schedule.
- Review of the existing pressure-temperature limit curves.
- Calculation of the pressurized thermal shock reference temperature values using the SPU fluence values for the beltline materials in the Seabrook Station reactor pressure vessel at the end of license.
- Review of the upper shelf energy values at end of license for the reactor pressure vessel beltline materials in the Seabrook Station reactor pressure vessel.

5.1.3.2 INPUT PARAMETERS AND ASSUMPTIONS

SPU Fluence Projections

The calculated fluence projections (LAR Subsection 5.1.2) on the reactor pressure vessel were evaluated for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) for input into the reactor pressure vessel integrity evaluations. Fluence values are used to evaluate end of license transition temperature shift for development of surveillance capsule withdrawal schedules, determining end of license upper shelf energy values, adjusted reference temperature values for determining applicability of heatup and cooldown curves, Emergency Response Guideline limits, and pressurized thermal shock reference temperature values. The calculated fluence projections used in the SPU evaluation comply with Regulatory Guide 1.190 [Reference 5.1-4].

Inlet Temperature

Due to the increase in licensed power level, the reactor pressure vessel inlet temperature will also change. This revised inlet temperature (LAR Section 2.0) has been reviewed to verify its compliance with Regulatory Guide 1.99 [Reference 5.1-7].

5.1.3.3 DESCRIPTION OF ANALYSIS/EVALUATIONS

The reactor pressure vessel integrity evaluation for the Seabrook Station SPU included the following five objectives. Results for each of these five objectives are discussed in more detail under LAR Subsection 5.1.3.5.

1. Review of the reactor pressure vessel surveillance capsule removal schedule to determine if changes are required as a result of changes in the vessel fluence due to the SPU.
2. Review of the existing pressure-temperature limit curves to determine if a new applicability date needs to be calculated due to the effects of the SPU fluence projections.

3. Calculation of reference temperature – pressurized thermal shock values for the beltline materials in the reactor pressure vessel based upon SPU fluence values at end of license of 40 Effective Full Power Years.
4. Review the upper shelf energy values at end of license of 40 Effective Full Power Years for the reactor pressure vessel beltline materials in the reactor pressure vessel to assess the impact of the SPU fluence projections.
5. Review reactor pressure vessel inlet temperature to verify that it maintains an acceptable level for the SPU conditions to verify that the temperature range is consistent with Regulatory Guide 1.99, which is the basis of 10 CFR 50.61.

Surveillance Capsule Withdrawal Schedules

A surveillance capsule withdrawal schedule is developed to periodically remove surveillance capsules from the reactor pressure vessel. This procedure is followed to effectively monitor the condition of the reactor pressure vessel materials under actual operating conditions. ASTM E185-82 [Reference 5.1-8] defines the recommended number of surveillance capsules and the recommended withdrawal schedule based on the vessel material predicted transition temperature shifts. The surveillance capsule withdrawal schedule is in terms of Effective Full Power Years of plant operation, with a design life of 40 Effective Full Power Years. Other factors that must be considered in establishing the surveillance capsule withdrawal schedule are maximum fluence values at the vessel inside surface and 1/4-thickness (1/4T) location.

A current surveillance capsule withdrawal schedule for the Seabrook Station reactor pressure vessel is documented in WCAP-10110 [Reference 5.1-9]. This schedule has been evaluated for the SPU due to the potential increase in the neutron fluence projections.

Heatup and Cooldown Pressure-Temperature Limit Curves

A review of the applicability dates of the heatup and cooldown curves for Seabrook Station was performed. The curves are currently contained in WCAP-15745 [Reference 5.1-10]. This review was carried out by comparing the fluence projections used in the current calculations of adjusted reference temperature for the beltline materials in the Seabrook Station reactor pressure vessel to the fluence projections based on the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) in LAR Subsection 5.1.2.

Pressurized Thermal Shock

Pressurized thermal shock, a limiting condition on reactor pressure vessel integrity, may occur during a severe system transient such as a loss of coolant accident or a steam line break. Such transients may challenge the integrity of a reactor pressure vessel under the following conditions:

- Severe overcooling of the inside surface of the reactor pressure vessel wall followed by high repressurization,

- Significant degradation of reactor pressure vessel material toughness caused by radiation embrittlement, and
- The presence of a critical-size defect in the reactor pressure vessel wall.

The pressurized thermal shock concern arises if one of these transients acts on the beltline region of a reactor pressure vessel where a reduced fracture resistance exists because of neutron irradiation. Such an event may produce the propagation of flaws postulated to exist near the inner wall surface, thereby potentially affecting the integrity of the reactor pressure vessel.

Emergency Response Guideline Limits

Emergency Response Guideline pressure-temperature limits were developed to establish guidance for operator action in the event of an emergency, such as a pressurized thermal shock event. Generic categories of limits were developed for the guidelines based on the limiting inside surface reference transition temperature. These generic categories were conservatively generated for the Westinghouse Owners Group to be applicable to all Westinghouse plants.

The highest end of license reference transition temperature for which the generic category Emergency Response Guideline pressure-temperature limits were developed is 250°F for a longitudinal flaw and 300°F for a circumferential flaw. Thus, if the limiting vessel material has an end of license reference transition temperature that exceeds 250°F for a longitudinal flaw or 300°F for a circumferential flaw, plant-specific Emergency Response Guideline pressure-temperature limits are required.

A calculation of the end of license reference temperature – pressurized thermal shock (which is the end of license reference transition temperature value (40 Effective Full Power Years)) has been made using the SPU values to determine what the applicable Emergency Response Guideline category would be for Seabrook Station.

Upper Shelf Energy

The integrity of the reactor pressure vessel may be affected by changes in system temperatures and pressures resulting from the SPU. To address this consideration, an evaluation was performed to assess the impact of the SPU on the upper shelf energy values for all reactor pressure vessel beltline materials in the Seabrook Station reactor pressure vessel. The upper shelf energy assessment used the results of the neutron fluence evaluation for the SPU and Figure 2 of Regulatory Guide 1.99 [Reference 5.1-7], to determine if a further decrease in upper shelf energy at end of license (40 Effective Full Power Years) would occur due to the effects of the SPU on fluence projections.

Inlet Temperature

Paragraph 1.3.2 of Regulatory Guide 1.99, which is the basis of 10 CFR 50.61 and used in the analyses described herein, stipulates that the equations are valid only in the temperature range of 525°F to 590°F. Therefore, the reactor pressure vessel

inlet temperature must be maintained within this range to retain validity of the existing analyses.

5.1.3.4 ACCEPTANCE CRITERIA

Surveillance Capsule Withdrawal Schedule

The proposed surveillance capsule withdrawal schedules developed for Seabrook Station following the SPU shall meet the requirements of ASTM-E185-82 [Reference 5.1-8]. A satisfactory number of surveillance capsules shall remain in the reactor pressure vessel so that further analysis, such as for license renewal, can be completed as necessary.

Heatup and Cooldown Pressure-Temperature Limit Curves

If the fluence projections for Seabrook Station increase from that used in the current heatup and cooldown curves, then new applicability dates must be calculated or new heatup and cooldown curves must be generated.

Pressurized Thermal Shock

The SPU reference temperature – pressurized thermal shock values for the beltline materials shall not exceed the screening criteria of the pressurized thermal shock rule. Specifically, the reference temperature – pressurized thermal shock values of the base metal (plates or forgings) shall not exceed 270°F, while the girth weld metal reference temperature – pressurized thermal shock values shall not exceed 300°F through the end-of-license (40 Effective Full Power Years).

Emergency Response Guideline Limits

The Emergency Response Guideline limits shall be developed to establish guidelines for operator action in the event of an emergency, such as a pressurized thermal shock event.

Upper Shelf Energy

At SPU conditions, the end of license upper shelf energy values for the reactor beltline materials shall meet the requirements of 10 CFR 50, Appendix G [Reference 5.1-2].

Inlet Temperature

The inlet temperature must be maintained in the range of 525°F to 590°F for the current analyses described herein to remain valid.

In addition, the applicable regulatory criteria are 10 CFR 50.60, 10 CFR 50.61, 10 CFR 50 Appendix H and General Design Criteria 1, 14, and 31.

5.1.3.5 RESULTS

An evaluation of the impact of an SPU on reactor pressure vessel integrity was performed for Seabrook Station. Per LAR Subsection 5.1.2, one can determine that after the SPU the neutron fluence projections for the Seabrook Station pressure-

temperature Curves have not increased from previous supporting analyses [Reference 5.1-11]. With respect to pressurized thermal shock, upper shelf energy, and the surveillance capsule withdrawal schedule, new evaluations were performed for the SPU fluence projections, and the results were compared to the respective screening criteria.

Surveillance Capsule Withdrawal Schedule

The current withdrawal schedule for Seabrook Station is contained in Reference 5.1-9. Using the updated capsule fluence values and the SPU reactor pressure vessel fluence projections, a calculation of end of license transition temperature shift at 40 Effective Full Power Years was performed to determine if the SPU reactor pressure vessel fluence projections alter the number of capsules to be withdrawn for Seabrook Station. This calculation determined that the maximum end of license transition temperature shift using the SPU fluences for Seabrook Station at end of license is less than 100°F. Per Reference 5.1-8, these end of license transition temperature shift values would require three capsules to be withdrawn from Seabrook Station, while the original withdrawal schedule in Reference 5.1-9 called for four capsules. Therefore, the current surveillance capsule withdrawal schedule remains acceptable for the SPU.

Applicability of Heatup and Cooldown Pressure-Temperature Limit Curves

Seabrook Station is currently operating to pressure-temperature limit curves documented in Reference 5.1-10, attached to LAR 02-04 [Reference 5.1-11]. A review based on SPU fluences was conducted on the current heatup and cooldown curve applicability date for Seabrook Station. This review indicates that the revised adjusted reference temperature after the SPU will be less restrictive than that used in developing the current adjusted reference temperature values for Seabrook Station at 20 Effective Full Power Years. Therefore, no change in applicability date is required after the SPU.

Pressurized Thermal Shock

The pressurized thermal shock calculations were performed for the Seabrook Station beltline materials using the latest procedures required by the NRC in 10 CFR 50.61 [Reference 5.1-3]. To evaluate the effects of the SPU, the pressurized thermal shock values for the beltline region materials from Seabrook Station were re-evaluated using the SPU fluences. Based on this evaluation, the reference temperature – pressurized thermal shock values will remain below the Nuclear Regulatory Commission screening criteria values using the projected SPU fluence values through end of license for 40 Effective Full Power Years for Seabrook Station and thus meet the requirements of 10 CFR 50.61.

Emergency Response Guideline Limits

For the SPU, the peak-inside surface reference transition temperature values at end of license were determined to be less than 200°F for Seabrook Station. The limiting material for Seabrook Station was the lower shell plate R-1808-1 for 40 Effective Full

Power Years. With these reference transition temperature values due to the SPU, Seabrook Station remains in Emergency Response Guideline Category I.

Upper Shelf Energy

The beltline materials were determined to have upper shelf energies greater than 50 ft-lb through the end of license (40 Effective Full Power Years), as required by 10 CFR 50 Appendices G and H [Reference 5.1-2]. The end of license upper shelf energies were predicted using the end of license 1/4T fluence projection. The upper shelf energy values for the beltline region materials from Seabrook Station were calculated using the SPU fluences. Based on this evaluation, the upper shelf energy values for Seabrook Station will maintain a level above the 50 ft-lb screening criterion through the end of license (40 Effective Full Power Years) for Seabrook Station. Thus, the upper shelf energy fracture toughness requirements for Seabrook Station meet the requirements of 10 CFR 50.61.

Inlet Temperature

Per LAR Section 2.0, which contains the SPU design parameters, the inlet temperature for Cases 1 through 4 are within the range of 525°F to 590°F. Thus, the reactor pressure vessel integrity evaluations remain valid.

5.1.3.6 CONCLUSIONS

The fluence projections associated with the SPU, while considering actual power distributions incorporated to date, will not adversely impact evaluations of record [References 5.1-2, 5.1-8, 5.1-10] (withdrawal schedules, Pressure-Temperature curves, Emergency Response Guideline, pressurized thermal shock, and upper shelf energy). The effect of the SPU fluence values is minimal for pressurized thermal shock and has not changed the Emergency Response Guideline limits in a negative way. With respect to the pressure-temperature curves, the current curves are documented in Reference 5.1-10. These pressure-temperature curves used fluences that were developed without the current SPU. However, it was determined that the SPU fluences have no effect on the existing 20 Effective Full Power Years pressure-temperature curves in Reference 5.1-11. Lastly, the inlet temperature will be maintained above 525°F for normal operation.

It is concluded that the Seabrook Station SPU will not have a significant effect on the reactor pressure vessel integrity. The reactor vessel material surveillance program will continue to meet the requirements of 10 CFR 50.60 and 10 CFR 50 Appendix H. The reactor vessel will continue to comply with General Design Criteria 1, 4, and 31. Therefore, the reactor pressure vessel integrity is acceptable at the SPU conditions.

TABLE 5.1-1
MAXIMUM RANGE OF STRESS INTENSITY AND CUMMULATIVE FATIGUE USAGE FACTORS

LOCATION	MAXIMUM RANGE STRESS INTENSITY	CUMULATIVE FATIGUE USAGE FACTOR
Head Flange, Vessel Flange & Closure Studs	Closure Head Flange 50.82 ksi < $3S_m$ = 80.1 ksi Vessel Flange 44.63 ksi < $3S_m$ = 80.1 ksi Closure Studs 88.55 ksi < $3S_m$ = 123.6 ksi	Head Flange 0.0155 < 1.0 Vessel Flange 0.0196 < 1.0 Closure Studs 0.4780 < 1.0
Bottom Head to Shell Juncture	49.9 ksi < $3S_m$ = 80.1 ksi	0.0070 < 1.0
Vessel Wall Transition	56.3 ksi < $3S_m$ = 80.1 ksi	0.0105 < 1.0
Inlet Nozzle & Support Pad	Inlet Nozzle Safe End: 47.6 ksi < $3S_m$ = 51.0 ksi Nozzle: 66.7 ksi < $3S_m$ = 80.1 ksi Support Pad 57.06 ksi < $3S_m$ = 80.1 ksi	Inlet Nozzle 0.0795 < 1.0 Support Pad 0.0266 < 1.0
Outlet Nozzle & Support Pad	Outlet Nozzle Safe End: (1) 54.6 ksi > $3S_m$ = 53.7 ksi Nozzle: 75.4 ksi < $3S_m$ = 80.1 ksi Support Pad 47.5 ksi < $3S_m$ = 80.1 ksi	Outlet Nozzle 0.1077 < 1.0 Support Pad 0.0211 < 1.0
Control Rod Drive Mechanism Housings	59.0 ksi < $3S_m$ = 69.9 ksi	0.1093 < 1.0
Bottom Head Instrument Tubes	Location 1 70.67 ksi > $3S_m$ = 69.9 ksi Location 2 58.93 ksi < $3S_m$ = 69.9 ksi	Location 1 0.0014 < 1.0 Location 2 0.3184 < 1.0
Core Support Lugs	60.55 ksi < $3S_m$ = 80.1 ksi	0.0627 < 1.0
Head Adapter Plugs	27.6 ksi < $3S_m$ = 48.6 ksi	0.0036 < 1.0

NOTES:

(1) Stress intensities are qualified using simplified elastic-plastic analysis per Subsection NB of the ASME Boiler and Pressure Vessel Code, this also applies to outlet nozzle safe end.

TABLE 5.1-2
REACTOR PRESSURE VESSEL / INTERNALS INTERFACE LOADS

LOCATION	INTERFACE LOAD	ALLOWABLE LOAD
Vessel-Barrel Flange Horizontal	187,000 lbs	6,040,000 lbs
Vessel-Barrel Flange Vertical	2,008,183 lbs	7,572,000 lbs
Vessel-Upper Support Plate Flange Horizontal	947,000 lbs	1,284,000 lbs
Vessel- Upper Support Plate Flange Vertical	1,292,183 lbs	3,457,000 lbs
Barrel Outlet Nozzle	101,000 lbs	1,052,000 lbs
Lower Radial Keys (Core Support Lugs)	1,464,499 lbs	5,661,178 lbs

5.2 REACTOR PRESSURE VESSEL INTERNALS

Evaluations were performed to assess the impact on the reactor pressure vessel internal components for the SPU at Seabrook Station based on an analyzed SPU core power level of 3659 (3678 MWt NSSS power level) for the design life. Thermal-hydraulic, rod drop time and structural evaluations of the reactor pressure vessel internals are described in this section for the SPU conditions.

5.2.1 INTRODUCTION

The reactor pressure vessel system consists of the reactor pressure vessel, reactor pressure vessel internals, and fuel and control rod drive mechanisms. The reactor pressure vessel internals' function is to 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 pressure vessel. The reactor pressure vessel internal components also function to direct coolant flow through the fuel assemblies (core), to provide adequate cooling flow to the various internals structures, and to support in-core instrumentation. They are designed to withstand forces due to structure deadweight, pre-load of fuel assemblies, 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 reactor pressure vessel system/fuel interface be thoroughly addressed in order to assure compatibility, and that the structural integrity of the reactor pressure 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 in order to provide input to the loss of coolant accident and non-loss of coolant accident safety analyses, as well as NSSS performance evaluations.

Generally, the areas that are potentially most affected by changes in system operating conditions are:

- Reactor pressure vessel internals system thermal/hydraulic performance
- Rod control cluster assembly scram performance
- Reactor pressure vessel internals system structural response and integrity

The major components and features of the reactor pressure vessel internals system for Seabrook Station 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, and supports the fuel assemblies on the sides and at the bottom. The guidance and alignment of the lower core support assembly during insertion into the reactor pressure vessel is provided by the radial support system and the head-vessel alignment pins, and special temporary guide studs attached to the 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, is provided by the head-vessel alignment pins, the upper core plate alignment pins in the core barrel assembly, and guide studs attached to the vessel. The alignment of the core, i.e., each fuel assembly, 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 pressure 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 reactor pressure 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 pressure vessel outlet nozzles. The perforations in the various components, such as the lower support plate, control and meter the flow through the core.

The purpose of this section is to summarize the work performed to assess the effect on the reactor pressure vessel internals system based on an increase to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

5.2.2 INPUT PARAMETERS AND ASSUMPTIONS

The principal input parameters utilized in the analysis of the reactor pressure vessel internal components and reactor pressure vessel system are the NSSS design parameters provided in LAR Section 2.0. For structural analysis/evaluations, the NSSS design transients discussed in LAR Section 3.0 were considered. The fuel considered is a full core of Westinghouse robust fuel assemblies with thimble plugging devices in-place. An additional case was also addressed with the thimble plugging devices removed.

5.2.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

Westinghouse has performed evaluations/analyses to assess the effect of the analyzed SPU core power level of 3659 (3678 MWt NSSS power level) on the reactor pressure vessel/internals system of the Seabrook Station. The description of various analyses and evaluations are given in the individual LAR Subsections 5.2.5 through 5.2.8.

5.2.4 ACCEPTANCE CRITERIA

The applicable General Design Criteria are 1, 2, 4, and 10. The acceptance criteria are listed in each individual section. However, some of the most important acceptance criteria are grouped together and given in the following subsections:

5.2.4.1 CORE BYPASS FLOW

The design core bypass flow limit with the thimble plugging devices in-place is 6.3% of the total vessel flow rate, and with the thimble plugging devices removed is 8.3% of the total vessel flow rate, per LAR Section 2.0.

5.2.4.2 HYDRAULIC FORCES

Hydraulic lift forces on the reactor pressure vessel internals must be limited so that the internals remain seated and stable.

5.2.4.3 CUMULATIVE FATIGUE USAGE FACTORS

For the structural and fatigue evaluations of the various reactor internal components, the cumulative fatigue usage factors should be less than 1.0 for the most critically stressed members.

5.2.5 THERMAL-HYDRAULIC SYSTEM EVALUATIONS

5.2.5.1 SYSTEM PRESSURE LOSSES

The principal Reactor Coolant System flow route through the reactor pressure vessel at Seabrook Station begins at the inlet nozzles. At this point, flow turns downward through the reactor pressure vessel/core barrel annulus. After passing through this down-comer region, the flow enters the lower reactor pressure vessel dome region. This region is occupied by the internals energy absorber structure, lower support columns, bottom-mounted instrumentation 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 pressure vessel through the four outlet nozzles. Note that the upper plenum region is occupied by support columns and rod control cluster assembly guide columns.

A key area in evaluation of core performance is the determination of hydraulic behavior of coolant flow within the reactor pressure vessel internals system, i.e., vessel pressure drops, core bypass flows, vessel fluid temperatures, hydraulic lift forces, and baffle joint momentum flux. The pressure loss data is necessary input to the loss of coolant accident and non-loss of coolant accident safety analyses and to overall NSSS performance calculations. The hydraulic forces are considered in the assessment of the structural integrity of the reactor pressure vessel internals, core clamping loads generated by the internals hold-down spring, and the stresses in the reactor pressure vessel closure studs.

The THRIVE computer code was used to perform this evaluation by solving the mass and energy balances for the reactor pressure vessel internals fluid system. This THRIVE analysis determined the distribution of pressure and flow within the reactor pressure vessel, internals, and the reactor core. Results were obtained with a full core of Westinghouse robust fuel assemblies with intermediate flow mixers,

assuming both thimble plugs removed and also with thimble plugs in-place, and at Reactor Coolant System conditions, as summarized in LAR Section 2.0.

5.2.5.2 BYPASS FLOW ANALYSIS

Description of Analyses

Bypass flow is the total amount of reactor coolant flow bypassing the core region and is 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 are used in order to demonstrate that the bypass flow limits are not violated. Therefore, analyses are 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 6.3% of the total reactor pressure vessel flow with the thimble plugging devices in-place and this limit is 8.3% of the total reactor pressure vessel flow with the thimble plugging devices removed. The purpose of this evaluation is to show that the design value of 6.3% or 8.3% can be maintained at the Reactor Coolant System conditions, as described in LAR Section 2.0. The principal core bypass flow paths are described in the following paragraphs.

Baffle-Barrel Region

The current reactor pressure vessel internals configuration incorporates upward coolant flow in the region between the core barrel and the baffle plates. In this configuration, a majority of the coolant exits the reactor pressure vessel inlet nozzle and flows downward in the annulus between the vessel and core barrel. The downward flow passes over the neutron pads 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 the Seabrook Station, the former plates have flow holes machined in them. Some flow from the lower plenum enters the baffle-barrel region at the lower core plate and exits above the core. There will also be some flow exchange between the baffle-barrel region and the core through the baffle plate gaps.

Vessel Head Cooling Spray Nozzles

These nozzles are flow paths between the 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 reactor pressure vessel inlet nozzles and into the vessel/barrel downcomer passes through these nozzles and into the vessel closure head region. The purpose of these flow paths is to allow circulation of a small fraction of the cold leg coolant into the upper head region of the reactor pressure vessel so that the mean bulk fluid temperature in the upper head remains at T_{cold}.

Core Barrel - Reactor Pressure Vessel Outlet Nozzle Gap

At Seabrook Station, some of the flow that enters the vessel/barrel downcomer passes through the gaps between the core barrel outlet nozzles and the reactor pressure vessel outlet nozzles and merges with the vessel outlet nozzle flow. Since the lower reactor pressure vessel internals are designed to be removable from the reactor pressure 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 pressure vessel internals and the reactor pressure vessel, there is some amount of flow which 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 referred to as the core cavity region. This is 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, in the analysis, such flow is not considered to be effective in heat removal, and is 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 impact of SPU Reactor Coolant System conditions on the total core bypass flow. The calculated core bypass flow values are 5.1% with the thimble plugging devices in-place and 7.0% with thimble plugging devices removed at the Reactor Coolant System conditions described in LAR Section 2.0. Therefore, the design core bypass flow value of 6.3% with thimble plugging devices in-place and 8.3% of the total vessel flow with the thimble plugging devices removed are maintained.

5.2.5.3 HYDRAULIC LIFT FORCES

An evaluation was performed to estimate hydraulic lift forces on the various reactor pressure vessel internal components for the SPU parameters shown in LAR Section 2.0. This is done to show that the reactor pressure vessel internals assembly would remain seated and stable for all conditions. If the impact of the proposed changes on lift forces is found to be significant, then the estimated hydraulic lift forces would be combined with other mechanical and body forces to evaluate the resultant pre-load of the core barrel flange against the reactor pressure vessel. Based on the

evaluation, the Seabrook Station reactor pressure vessel internals will remain seated and stable for the SPU Reactor Coolant System conditions.

5.2.5.4 MOMENTUM FLUX AND FUEL ROD STABILITY

Baffle jetting is a hydraulically induced instability or vibration of fuel rods caused by a high velocity jet of water. This jet is created by high pressure water being forced through gaps between the baffle plates which surround the core. The baffle-jetting phenomenon could lead to fuel cladding damage.

With the Westinghouse standard upflow design baffle barrel region configurations, the momentum flux margins remain acceptable based on the evaluations performed for the Seabrook Station SPU.

5.2.5.5 UPPER HEAD FLUID TEMPERATURES

The average temperature of the primary coolant fluid that occupies the reactor pressure vessel closure head volume is an important initial condition for certain dynamic loss of coolant accident analyses. Therefore, it was necessary to determine the upper head temperature when changes in the Reactor Coolant System conditions take place. Determination of upper head temperature stemmed from the THRIVE evaluations used to assess the core bypass flow. The THRIVE code models the interaction between the different flow paths into and out of the closure head region. Based on this interaction, it calculates the core bypass flow into the head region and average head fluid temperature for different flow path conditions. Seabrook Station is configured such that the upper head region is at T_{cold}. This evaluation showed that the upper head region best estimate mean fluid temperature is at T_{cold} for the Reactor Coolant System conditions described in LAR Section 2.0.

5.2.5.6 ROD CONTROL CLUSTER ASSEMBLY SCRAM PERFORMANCE EVALUATION

The rod control cluster assemblies represent perhaps the most critical interface between the fuel assemblies and the other internal components. It is imperative to show that the SPU Reactor Coolant System conditions will not adversely impact the operation of the rod control cluster assemblies, either during accident conditions or normal operation.

In general, a plant-specific rod control cluster assembly drop time performance assessment involves the following steps:

1. Obtain actual plant drop time-to-dashpot entry data at no-flow and full-flow conditions for each rod control cluster assembly location.
2. Modeled the plant's driveline configuration and system operating conditions corresponding to those measurements. A driveline configuration is considered to be that subset of components affecting rod control cluster assembly drop time. These components are the fuel, upper core plate, upper and lower guide tubes, upper support plate, reactor closure head penetration, thermal sleeve, control rod drive mechanism, rod travel housing, and the rod control cluster assembly/drive rod assembly. The system operating conditions include temperature, pressure,

and flow. The driveline model consists of values for parameters that describe geometry of driveline components, component mechanical interaction relationships, hydraulic resistances of flow paths, rod control cluster assembly/drive rod assembly weight, and system operating conditions.

3. Use a coded algorithm previously developed by Westinghouse, with the driveline 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 as it applies to the rod control cluster assembly evaluation is defined by:

$$\Sigma F = (W/g) \times (dV/dt)$$

where:

ΣF	=	Sum of various forces acting on the rod control cluster assembly/drive rod assembly at any time, (t)
W	=	total weight of rod control cluster assembly/drive rod assembly
g	=	acceleration due to gravity, (32.2 ft/sec^2)
V	=	assembly velocity, (ft/sec)
t	=	drop time after control rod drive mechanism latch release of drive rod, (sec)

   The correlation involves adjustment of specific code input parameters:

   a) Characterize rod control cluster assembly drop performance from no-flow (0 percent) through full-flow (100%) flow based on zero-flow and full-flow core average drop time measurements, and

   b) Isolate and account for the effects of variations in drive line mechanical interference drag force under normal conditions, and variations in drive line flows across the core, based on core-maximum drop time measurements at zero-flow and full-flow, respectively.

   Adjust the model (i.e., DROP input parameter values) to account for the new system operating conditions being considered due to the SPU. Also, conservatively account for:

   a) Component geometric design tolerances

   b) Hydraulic performance uncertainties (related to fuel assembly hydraulic resistance, guide tube/ rod control cluster assembly wear, and reactor coolant flow rate)

   c) Abnormal environmental conditions

4. Assess the impact of such changes in driveline components and/or primary system operating conditions on the limiting rod control cluster assembly drop time characteristics used in the plant accident analyses. These limiting characteristics are the most severe drop time-to-dashpot entry and normalized rod control cluster assembly drop time position-versus-time relationship

estimated based on the tolerances, uncertainties, and abnormal environmental conditions identified above.

The analysis that was performed determined the potential impact of the conditions shown in LAR Section 2.0 on the limiting rod control cluster assembly drop time. The maximum estimated rod control cluster assembly drop time remains less than the current Seabrook Station Technical Specification limit of 2.4 seconds.

5.2.6 MECHANICAL SYSTEM EVALUATIONS

The Reactor Coolant System mechanical response to loss of coolant accident auxiliary line break transients is performed in three steps. First, the Reactor Coolant System 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 reactor pressure vessel, which would result from release of equilibrium forces at the break locations, are obtained. In the second step, the loop mechanical loads and reactor pressure vessel internals hydraulic forces are simultaneously applied, and the reactor pressure vessel displacements due to the loss of coolant accident are calculated. Finally, the structural integrity of the reactor coolant loops and component supports to deal with the loss of coolant accident are evaluated by applying the calculated reactor pressure vessel displacements to a mathematical model of the reactor coolant loops. Thus, the effects of vessel displacements upon the reactor coolant loops and reactor pressure vessel/internals are evaluated.

5.2.6.1 LOSS OF COOLANT ACCIDENT LOADS

To perform the reactor pressure vessel loss of coolant accident analyses of the Seabrook Station, a finite element model of the reactor pressure vessel system is developed. The mathematical model of the reactor pressure vessel is a three-dimensional non-linear finite element model that represents the dynamic characteristics of the reactor pressure 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) has been used for this analysis since the original plant design.

The WECAN computer code, which is used to determine the response of the reactor pressure 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.

In order to evaluate the impact of changes in Reactor Coolant System conditions on the dynamic response of the reactor pressure vessel system, loss of coolant accident analyses were performed to generate core plate motions and the reactor pressure

vessel/internals interface loads. The core plate motions are then used to evaluate the structural integrity of the core. Since application of leak-before-break methodology has been licensed for the main coolant loops, consideration of breaks in the main coolant loops are not required for structural evaluations.

The next limiting breaks to be considered are the branch line breaks. The hydraulic loss of coolant accident forces (LAR Subsection 6.1.7) for the breaks listed below are used in the reactor pressure vessel loss of coolant accident analysis:

- Accumulator lines (cold legs)
- Pressurizer surge line (hot leg)

Seismic Analyses

The non-linear time history seismic analyses of the reactor pressure vessel system include the development of the system finite element model and the synthesized time history accelerations.

Similar to the response during loss of coolant accidents, the reactor pressure vessel system seismic model included sub-models of the reactor pressure vessel, nozzles, internals, fuel and control rod drive mechanisms. The WECAN finite element model described for loss of coolant accidents was modified to include the fluid-structure interaction in the reactor pressure vessel model for the seismic safe shutdown earthquake (SSE) time history evaluations. The WECAN reactor pressure vessel/internals/fuel assembly model incorporated the effects of fluid-structure interaction in the down-comer region via hydrodynamic mass matrices between two concentric cylinders (between the core barrel and reactor pressure vessel). The fluid-structure interaction in the seismic analysis is different from that included in the loss of coolant accident analysis. In the loss of coolant accident analysis, the fluid-structure interaction is included through the MULTIFLEX code [Reference 6.1-5]; whereas in the seismic analysis, the fluid-structure interaction in the downcomer region (between the core barrel and reactor pressure vessel) is incorporated through the hydrodynamic mass matrices. The mass matrices with off-diagonal terms are incorporated between nodes on the core barrel and reactor pressure vessel shell. For a time history response of the reactor pressure vessel and its internals under seismic excitation, synthesized time history accelerations are required. The synthesized time history accelerations used in the reactor pressure vessel system analysis were based on the applicable response spectra for Seabrook Station. The resulting north-south, east-west and vertical acceleration time history accelerations are generated for the safe shutdown earthquake events.

The results of the system seismic analysis include time history displacements and impact forces for the major components. The reactor pressure vessel displacements and the impact forces calculated at vessel/internals interfaces are used to evaluate the structural integrity of the reactor pressure vessel and its internals. The core plate motions were used in fuel grid crush analysis and to confirm the structural integrity of the fuel.

5.2.6.2 FLOW-INDUCED VIBRATIONS

Flow-induced vibrations of pressurized water reactor pressure vessel internals have been studied at Westinghouse for a number of years. The objective of these studies is to show the structural integrity and reliability of reactor internal components. 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 compliment one another and make possible a better understanding of the flow-induced vibration phenomena. Based on the analysis performed for the Seabrook Station reactor pressure vessel internals, response due to flow-induced vibrations is extremely small and well within the allowable limits based on the high cycle endurance limit for the material.

5.2.7 STRUCTURAL EVALUATION OF REACTOR INTERNAL COMPONENTS

In addition to supporting the core, a secondary function of the reactor pressure 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 pressure 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. Also, 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 demonstrate that the structural integrity of reactor internal components is not adversely affected either directly by the SPU 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, results in thermal gradients within and between components. These thermal gradients result in thermal stresses and thermal growth, which must be considered in the design and analysis of the various components.

The Seabrook Station reactor pressure vessel internals were designed to meet the intent of Section III, Subsection NG of the ASME Boiler and Pressure Vessel Code. Plant-specific stress report on the reactor pressure vessel internals was not required. The structural integrity of the Seabrook Station reactor pressure vessel 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 Seabrook Station reactor internal components for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and revised design transients.

5.2.7.1 LOWER CORE PLATE

Structural evaluations were performed to demonstrate that the structural integrity of the lower core plate is not adversely affected either by the SPU 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 Boiler and Pressure Vessel Code were utilized.

Primarily because of the higher gamma heating rates associated with the SPU conditions, the lower core plate stresses are impacted. The conclusion of these evaluations is that structural integrity of the lower core plate is maintained. The SPU conditions produced acceptable margins of safety and fatigue utilization factors for the ligaments under all loading conditions. The limiting (highest) cumulative usage factor for the Seabrook Station lower core plate at the SPU conditions is [ ], which is less than the ASME Boiler and Pressure Vessel Code limit of 1.0. (Note: This information is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.)

5.2.7.2 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 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.

The stresses in the upper core plate are mainly due to hydraulic and thermal loads. The total thermal stresses are due to thermal bending moments through the thickness and surface peak stresses. An evaluation was performed to determine the impact of SPU on the structural integrity of the upper core plate. As a result of this evaluation, it is concluded that the upper core plate is structurally adequate for the SPU conditions at Seabrook Station. The limiting (highest) cumulative usage factor for the Seabrook Station upper core plate at SPU conditions is [ ], which is less than the ASME Boiler and Pressure Vessel Code limit of 1.0. (Note: This information is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.)

5.2.7.3 BAFFLE-BARREL REGION COMPONENTS

The Seabrook Station 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 neutron panel 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 pressure vessel internals configuration for Seabrook Station utilizes upflow in the barrel-baffle region.

5.2.7.3.1 CORE BARREL EVALUATION

The thermal stresses in the active core 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 conditions. These evaluations indicated that the actual number of fatigue cycles, based on the normal/upset conditions, was well below the allowable value. From these conservative results, it has been concluded that the core barrel is structurally adequate for the Seabrook Station SPU conditions.

5.2.7.3.2 BAFFLE-BARREL BOLT EVALUATION

The bolts are evaluated for loads resulting from hydraulic pressure, seismic loads, preload, and thermal conditions. The temperature difference between baffle and barrel produces the dominant loads on the baffle-former bolts. Hydraulic pressure and seismic loads produce the primary stresses, whereas bolt preloading and thermal conditions produce the secondary stresses. The SPU does not affect deadweight or preload forces.

Since these bolts are qualified by test, the revised loads for the SPU were compared with the loads qualified in the test program. The evaluation demonstrated that the loads associated with the SPU are bounded by the loads qualified in the test program. Therefore, it is concluded that the baffle-former and barrel-former bolts are structurally adequate for the SPU conditions.

5.2.7.4 ADDITIONAL COMPONENTS

A series of assessments were performed on reactor internal components that were not significantly impacted by the SPU (and the resulting internal heat generation rates), but are affected by the SPU conditions due to primary loop design transients. These components are:

- Upper core plate alignment pins
- Lower support columns
- Upper support columns
- Lower radial restraints (clevis inserts)
- Core barrel outlet nozzle
- Upper support plate
- Baffle plate
- Neutron panel

The results of these assessments demonstrate that the above listed components are structurally adequate for the SPU conditions and the fatigue usage factors were less than 1.0.

5.2.7.5 CONCLUSIONS

Analyses have been performed to assess the effect of changes due to operating at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) at Seabrook Station. The results of these analyses are as follows:

- The design core bypass flow value of 6.3% of the total vessel flow with thimble plugging devices in-place and 8.3% with thimble plugging devices removed is supported for the SPU conditions.
- Hydraulic forces at the SPU conditions were evaluated for effects on the reactor pressure vessel internals. It was determined that the Seabrook Station reactor pressure vessel internals assemblies will remain seated and stable at the SPU conditions.
- A rod control cluster assembly performance evaluation was completed and indicated that the current 2.4 second rod control cluster assembly drop-time-to-dashpot entry limit (from gripper release of the drive rod) is satisfied at the SPU conditions.
- Baffle plate momentum flux margins of safety due to SPU conditions are relatively unchanged from present conditions for mechanical design flow, and remain acceptable.
- Evaluations were completed and indicated that the SPU conditions will not adversely impact the response of reactor pressure vessel internals systems and components due to seismic/loss of coolant accident excitations and flow induced vibrations.
- Evaluations of the critical reactor internal components were performed, which indicated that the structural integrity of the reactor pressure vessel internals is maintained at the SPU conditions. Limiting cumulative usage factors were shown to be less than 1.0.
- By meeting the design bases, the reactor vessel internals comply with General Design Criteria 1, 2, 4, and 10.

5.2.8 REACTOR PRESSURE VESSEL INTERNALS HEAT GENERATION RATES

5.2.8.1 INTRODUCTION

The presence of radiation-induced heat generation in reactor pressure vessel internals components, in conjunction with the various reactor coolant fluid temperatures, results in thermal gradients within and between the components. These thermal gradients cause thermal stress and thermal growth, which must be considered in the design and analysis of the various components for the SPU conditions. The reactor pressure vessel internals must be analyzed with respect to fatigue and maximum allowable stress considerations.

The reactor pressure vessel internals components subjected to significant radiation-induced heat generation are the upper and lower core plates, lower core support, core baffle plates, former plates, core barrel, neutron pad, baffle-former bolts, and barrel-former bolts. However, due to relatively low heat generation rates in the lower core support and the neutron pads, these components experience little, if any, temperature rise relative to the surrounding reactor coolant.

5.2.8.2 KEY INPUT ASSUMPTIONS

For the core plates, baseline gamma heating rates were determined for both long- and short-term conditions. Long-term heat generation rates intended to represent time-averaged behavior are used in component fatigue analyses, whereas the short-term results are intended to provide conservative values for use in calculating maximum temperatures and thermal stresses of components. For the long-term heat generation rate evaluation of the core plates, a reactor power level of 3950 MWt (standard Westinghouse generic four loop analysis assumption) scaled down to an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) was utilized in conjunction with a flat axial core power distribution, since these parameters significantly influence the core plate gamma heating rates and the aforementioned conditions conservatively bound the Seabrook Station SPU. For the short-term heat generation rate evaluation of the upper core plate, the reactor power of 3950 MWt (standard Westinghouse generic four loop analysis assumption) scaled down to an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) continued to be assumed and a conservative design-basis top-peaked axial power distribution was utilized. Analogous conditions were applied in the short-term heating rate evaluation of the lower core plate.

A long-term analysis was performed for the radial reactor pressure vessel internals components since it was anticipated that the current Seabrook Station gamma heating rates would be bounded by the existing data. Since the long-term radial case was shown to be bounding, the short-term radial case would also remain bounding and, therefore, was not calculated. The long-term heat generation rate bounding evaluation of the core baffle plates, core barrel, and neutron pads was based on the Cycle 12 radial power distribution forecasted for use by Seabrook Station operating at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

Design basis heat generation rates applicable to the Seabrook Station radial internals were used in the evaluation. The core power distributions upon which those calculations were based were derived from statistical studies. Most of the evaluated fuel cycles were based on an out-in fuel loading strategy (fresh fuel on the periphery) which, when combined with the statistical processing of the data, resulted in a design basis core power distribution that tended to be biased high on the periphery.

5.2.8.3 ACCEPTANCE CRITERIA

There are no specific acceptance criteria since this is an input to the reactor pressure vessel internals evaluation that is described in LAR Subsection 5.2.7.

5.2.8.4 DESCRIPTION OF ANALYSIS / EVALUATION AND RESULTS

The heat generation rate analyses were carried out using the DORT computer code and a cross-section library. This code has been utilized to support numerous reactor pressure vessel fluence evaluations and are accepted by the Nuclear Regulatory Commission for deterministic particle transport calculations, e.g., neutron exposure and gamma-ray heating rate evaluations.

The results of the radiation-induced heat generation rate calculations were provided as inputs for the reactor pressure vessel internals evaluations described in LAR Subsection 5.2.7. The volume-averaged heat generation rates for the core plates and radial reactor internal components were evaluated as part of this study.

As expected, the revised Seabrook Station zone average gamma heating rates for the core plates tended to be higher than the previous data. As a result, the spatial distributions of long-term and short-term heating rates for the upper and lower core plates were also identified for consideration as part of the component evaluation that is described in LAR Subsection 5.2.7. The evaluation demonstrated that the current Seabrook Station zone average gamma heating rates for the core baffle, core barrel, and neutron pads for the SPU, continue to remain bounded by the conservative radial component current heating rates.

5.2.8.5 CONCLUSIONS

The component gamma heating rates were provided as inputs to the reactor pressure vessel internals structural evaluation described in LAR Subsection 5.2.7.

5.3 FUEL ASSEMBLY STRUCTURAL ANALYSIS

This section summarizes the seismic and loss of coolant accident analysis of the robust fuel assemblies for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The robust fuel assembly homogeneous core was evaluated for the SPU conditions. The analytical model was analyzed for safe shutdown earthquake and loss of coolant accident (accumulator line break) limiting load conditions, which were obtained from the analysis of the reactor pressure vessel internals.

5.3.1 DESCRIPTION OF ANALYSES AND EVALUATIONS

The robust fuel assembly responses under seismic and loss of coolant accident load conditions were analyzed using an analytical model representation of a reactor core (WEGAP). The grid impact loads resulting from a combined safe shutdown earthquake and the accumulator line break loss of coolant accident loading conditions are well below the allowable grid strengths for the homogeneous core. The maximum square root of the sum of the squares mid-grid impact force of the robust fuel assembly is only 42.4% of the robust fuel assembly mid-grid crush strength. The maximum square root of the sum of the squares intermediate flow mixer-grid impact force of the robust fuel assembly is only 15.6% of the robust fuel assembly intermediate flow mixer-grid crush strength. The results show adequate grid load margin and that the core coolable geometry and control rod insertion requirements are met.

5.3.2 RESULTS

The stress evaluation of the robust fuel assembly thimble tube and fuel rod for Seabrook Station SPU is bounded by the previous calculation for Seabrook Station which was performed to support implementation of robust fuel assembly fuel. These results show that fragmentation of the robust fuel assembly fuel rods and thimble tubes will not occur.

5.3.3 CONCLUSIONS

Therefore, the robust fuel assembly is structurally and mechanically acceptable in a 4-loop homogeneous core for the Seabrook Station SPU.

5.4 CONTROL ROD DRIVE MECHANISMS

5.4.1 INTRODUCTION

This section addresses the ASME Boiler and Pressure Vessel Code structural considerations for the pressure boundary components of the full length Model L-106A1 control rod drive mechanisms and capped latch housings for Seabrook Station. The control rod drive mechanisms and capped latch housings were evaluated for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Design operating parameters are provided in LAR Section 2.0 and the associated NSSS design transients are discussed in LAR Section 3.0. This evaluation confirms continued structural acceptability of the pressure boundary components of the existing control rod drive mechanisms and capped latch housings for the Seabrook Station SPU.

5.4.2 INPUT PARAMETERS AND ASSUMPTIONS

The Seabrook Station Model L-106A1 control rod drive mechanisms and capped latch housings were originally designed and analyzed to generic component design reports and the ASME Boiler and Pressure Vessel Code [Reference 5.4-1]. The input parameters that were used to perform the analyses and evaluations for the analyzed SPU core power level of 3659 (3678 MWt NSSS power level) include the SPU design operating parameters, NSSS design transients, and the current design basis evaluations for the control rod drive mechanisms and capped latch housings. No additional input was required for the control rod drive mechanism and capped latch housing analyses and evaluations for the proposed SPU.

There were no other changes to the pressure or thermal design parameters considered for the SPU. Seismic analyses and non-pressure boundary component evaluations are unaffected by the SPU.

5.4.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The ASME Boiler and Pressure Vessel Code structural and fatigue limits and criteria of the generic control rod drive mechanism and capped latch housing reports are used to define the basis of the adequacy in the current evaluations of Seabrook Station. The ASME Boiler and Pressure Vessel Code year and addenda applicable for this analysis is based on Reference 5.4-1. The applicable General Design Criteria are 4, 23, 25, 26, 27, 28, and 29.

The control rod drive mechanisms and capped latch housings are installed in the reactor vessel upper head and are affected by reactor coolant pressure, reactor vessel head temperature, and cold leg NSSS design transients. The reactor coolant pressure is the same for the SPU and did not change from the original analysis. Since the reactor coolant pressure remains the same as originally specified, the control rod drive mechanisms and capped latch housings remain bounded for the SPU reactor coolant pressure condition.

The highest reactor vessel outlet temperature determined for the SPU is 621.4°F. Since most of the previous analyses used material allowables based on the design temperature of 650°F, the proposed temperature is enveloped by the previous analyses. The only evaluations that were not bounded were those associated with the changes in NSSS design transients that were not enveloped by the current analyses. Ratios of the new transients to the old transients were used (very small change, less than 5%) to multiply the existing stress evaluation results. After this was performed, it was shown that the component stresses were within the allowable limits of the ASME Boiler and Pressure Vessel Code.

5.4.4 CONCLUSIONS

The Seabrook Station control rod drive mechanisms and capped latch housings were evaluated for the SPU conditions and the associated NSSS design transients. In most cases, the existing analyses and evaluations remained applicable and bounding. Where this was not the case, new calculations were performed for the limiting components and the results demonstrate that the structural acceptability of the control rod drive mechanism and capped latch housing pressure boundary components are in accordance with Section III of the ASME Boiler and Pressure Vessel Code. The control rod drive mechanisms also demonstrate continued compliance with General Design Criteria 4, 23, 25, 26, 27, 28, and 29.

5.5 REACTOR COOLANT LOOP PIPING AND SUPPORTS

5.5.1 INTRODUCTION AND BACKGROUND

The conditions associated with the Seabrook Station analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) were evaluated to determine the effects on the existing as-built design basis reactor coolant loop analysis for the following components:

- Reactor coolant loop piping stresses and displacements
- Primary equipment nozzle loads
- Primary equipment support loads
- Pressurizer surge line piping stresses and displacements including the effects of thermal stratification
- Impact on reactor coolant loop branch nozzle loads
- Impact on Class 1 auxiliary piping systems

5.5.2 INPUTS AND ASSUMPTIONS

The following four sets of input parameters were considered in the evaluation:

- Nuclear Steam Supply System (NSSS) design parameters (LAR Table 2.3-1)
- NSSS design transients (LAR Section 3.0)
- LOCA hydraulic forcing functions loads (LAR Subsection 6.1.7) and associated reactor pressure vessel motions (LAR Section 5.2)
- Feedwater and main steam line breaks (LAR Subsections 6.4.4, 6.4.5, and Section 6.5)

The acceptance criteria for the reactor coolant loop analysis, including the reactor coolant loop branch nozzles remain unchanged from the design basis as-built analysis. For stress analysis purposes the reactor coolant loop piping is qualified in accordance with the requirements established in ASME Boiler and Pressure Vessel Code 1977 Edition including Summer 1979 Addenda [Reference 5.5-2]. The applicable General Design Criteria for the reactor coolant piping and auxiliary lines are 1, 2, 4, 14, and 15.

The acceptance criteria for the primary equipment supports remain unchanged from the design basis as-built analysis. Reactor coolant loop equipment supports are qualified in accordance with the requirements of Section III, Subsection NF of the ASME Boiler and Pressure Vessel Code, 1974 Edition with Addenda to and including Summer of 1974 Addenda [Reference 5.5-3]. The applicable General Design Criteria for the reactor coolant piping and auxiliary lines are 1, 2, 4, 14, and 15.

Class 1 auxiliary lines are qualified in accordance with Section III of the ASME Boiler and Pressure Vessel Code, 1977 Edition through the Summer 1979 Addenda

[Reference 5.5-2]. Surge line thermal stratification is addressed in accordance with NRC Bulletin 88-11 [Reference 5.5-4]. Fatigue usage factors for the Seabrook Station surge line are evaluated based on the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1986 Edition [Reference 5.5-1].

The parameters associated with the SPU Program were reviewed for impact on the existing reactor coolant loop piping analysis and subsequent impact to the reactor coolant loop branch nozzle qualification and the Class 1 auxiliary lines attached to the reactor coolant loop. The conclusions of this review are summarized below.

5.5.2.1 NUCLEAR STEAM SUPPLY SYSTEM DESIGN OPERATING PARAMETERS

The design parameters as identified in LAR Table 2.3-1 were compared with the design basis as-built thermal analysis for the reactor coolant loop. The reactor coolant loop piping was evaluated for the conditions associated with reactor coolant system T_{avg} of 589.1°F and 571.0°F. The reactor coolant loop piping stress analysis results are more limiting at a T_{avg} of 589.1°F. The reactor coolant temperatures for the SPU increase by a small amount compared to the current temperatures. This temperature variation is considered insignificant for the piping analysis. Therefore, the impact on the reactor coolant loop analysis due to the SPU design conditions is not significant.

5.5.2.2 NUCLEAR STEAM SUPPLY SYSTEM DESIGN TRANSIENTS

The impact due to the design transient changes for the SPU on the reactor coolant loop fatigue analysis was evaluated and found to be insignificant.

The controlling transients for the pressurizer surge line fatigue were evaluated and found to be not affected by the SPU. Therefore, the SPU has no adverse effect on either the thermal stratification or the fatigue analysis for the pressurizer surge line.

The impact of changes to the design transients for the SPU on the reactor coolant loop branch and Class 1 auxiliary lines fatigue analysis was determined to be insignificant. Therefore, the current fatigue evaluations remain applicable.

5.5.2.3 LOCA HYDRAULIC FORCING FUNCTIONS LOADS AND ASSOCIATED REACTOR PRESSURE VESSEL MOTIONS

The impact on the LOCA hydraulic forcing functions due to the SPU Program is addressed in LAR Subsection 6.1.7. Leak Before Break is applicable for the reactor coolant main loop piping as described in LAR Section 5.12.

The reactor coolant loop analysis was evaluated for the breaks at the auxiliary nozzles for the 12-inch residual heat removal lines, the-14-inch pressurizer surge line, and the 10-inch accumulator lines. Reactor pressure vessel motions corresponding to the surge line break, residual heat removal line break and accumulator line break were also used.

Additionally, the reactor coolant loop piping was evaluated for secondary side breaks at the main steam line and feedwater line terminal end nozzle locations at the steam generator.

5.5.3 ANALYSIS METHODS

The system analysis of the reactor coolant loop piping was performed using the WESTDYN program for the thermal expansion and LOCA cases.

Since there are no changes in the weight of the system, deadweight analysis is not required for the SPU. The reactor coolant loop analysis was performed utilizing the current support gap tolerance such that the existing design seismic time history analysis remains valid.

The equipment support loads from the high and low T_{avg} cases and reactor coolant loop LOCA analyses for the SPU are compared to the equipment support loads from the design as-built thermal and LOCA analysis to determine if the existing analyses are still valid.

5.5.4 REACTOR COOLANT LOOP PIPING ANALYSIS AND RESULTS

The evaluation of the reactor coolant loop includes performing thermal expansion, LOCA, main steam line and feedwater line break analyses.

The LOCA analysis for the reactor coolant loop is performed considering time history hydraulic forces distributed throughout the reactor coolant loop system. Based on the application of Leak Before Break, the analysis is performed for the breaks at the auxiliary nozzles for the 12-inch residual heat removal lines, the-14-inch pressurizer surge line, and the 10-inch accumulator lines. Reactor pressure vessel motions corresponding to the surge line break, residual heat removal line breaks and accumulator line breaks were also used.

The jet and thrust forces from the steam line double break calculated with the steam pressure for the SPU are bounded by the forcing functions obtained with the pressure from the existing analysis. Therefore, the existing piping analysis results from the main steam nozzle break are bounding and still applicable.

The reactor coolant loop piping analysis for the feedwater line nozzle break was performed and results were shown to be acceptable.

The maximum reactor coolant loop piping stresses for the reactor coolant loop piping and the corresponding code-allowable stress values are presented in LAR Table 5.5-1. (NOTE: *Information in this table is considered proprietary by Westinghouse* and is provided in separate FPL Energy Seabrook correspondence, Letter No.04-017)

The primary equipment nozzle loads are compared to the loads previously evaluated. The equipment nozzle loads are acceptable and the SPU Program has no adverse impact on the current as-built analysis results.

The impact on reactor coolant loop piping displacements at the reactor coolant loop branch nozzles and corresponding Class 1 auxiliary piping systems is insignificant

due to the SPU parameters, revised LOCA hydraulics, and reactor pressure vessel displacements. Therefore, the impact on the reactor coolant loop branch nozzles and the corresponding Class 1 piping systems due to the SPU is considered negligible. The reactor coolant loop piping and equipment displacements from the deadweight, thermal, and seismic as-built analyses remain valid.

The reactor coolant loop LOCA piping and equipment displacements from the reactor coolant loop as-built LOCA are still governing and remain applicable for the SPU.

Additionally, the current design basis pressurizer surge line analysis results including the effects of thermal stratification are applicable for the SPU Program.

5.5.5 PRIMARY EQUIPMENT SUPPORTS ANALYSIS AND RESULTS

The primary equipment supports have been evaluated for the revised loads associated with the SPU.

The equipment support loads associated with the SPU were compared with the loads previously evaluated and qualified for the as-built piping analysis. Primary equipment support loads were determined to be less than the existing loads for the qualified supports except for the faulted condition load at the steam generator upper support perpendicular to the hot leg. The faulted condition stresses on the steam generator upper support were then compared to the allowable stresses and determined to be acceptable.

Based on these evaluations, the primary equipment support stresses remain within the acceptance criteria.

5.5.6 CONCLUSIONS

The parameters associated with the Seabrook Station SPU have been evaluated for the following components:

- Reactor coolant loop piping stresses and displacements
- Primary equipment nozzle loads
- Primary equipment support loads
- Pressurizer surge line piping stresses and displacements, including the effects of thermal stratification
- Impact on reactor coolant loop branch nozzle loads
- Impact on Class 1 auxiliary piping systems

The evaluation indicates that the parameters associated with the SPU have no adverse effect on the analysis of the reactor coolant loop piping system, including impacts to the primary equipment nozzles and primary equipment supports. Reactor coolant loop piping stresses meet the required stress criteria, as summarized in LAR Table 5.5-1. (Note: Information in this table is considered proprietary by Westinghouse and provided in separate FPL Energy Seabrook correspondence letter number 04-017.) Reactor coolant loop piping loads from the Leak Before

Break evaluation for the SPU were evaluated and found to be acceptable (refer to LAR Section 5.12). Reactor coolant loop primary equipment support loads were evaluated and determined to be acceptable.

Reactor coolant loop piping displacements at branch nozzles previously evaluated for the as-built piping analysis remain valid for the SPU. Therefore, the SPU has no subsequent impact to either the reactor coolant loop branch nozzle loads or the Class 1 auxiliary piping systems that are attached to the reactor coolant loops.

The current design basis analysis results for the pressurizer surge line, including the effects of thermal stratification (Reference 5.5-4), are still applicable and remain valid for the SPU. By meeting their design bases, the reactor coolant piping, Class 1 auxiliary lines, and primary equipment supports continue to comply with General Design Criteria 1, 2, 4, 14, and 15.

TABLE 5.5-1

RCL STRESS ANALYSIS SUMMARY – SPU PROGRAM

Stress Condition	Hot Leg		Crossover Leg		Cold Leg	
	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi
Note: Information in this table is considered proprietary by Westinghouse and provided in separate FPL Energy Seabrook correspondence letter number 04-017.)						

5.6 PRESSURIZER

5.6.1 STRUCTURAL ANALYSIS

The functions of the pressurizer are to absorb any expansion or contraction of the primary reactor coolant due to changes in temperature and/or pressure and, in conjunction with the pressure control system components, to keep the Reactor Coolant System 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, connecting the pressurizer to the Reactor Coolant System at the hot leg of one of the reactor coolant loops, and allowing inflow to, or outflow from the pressurizer as required. 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 steam temperature differences.

The limiting operating conditions of the pressurizer occur when the Reactor Coolant System pressure is high and the Reactor Coolant System 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 Reactor Coolant System hot leg at T_{hot}. If the Reactor Coolant System 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 Reactor Coolant System 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.

This evaluation is based on the range of NSSS operating parameters presented in LAR Section 2.0 to support an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The reactor pressure vessel outlet (T_{hot}) and the reactor pressure vessel/core inlet (T_{cold}) temperatures in LAR Section 2.0 define the normal operating temperatures for the surge and spray lines to the pressurizer. The pressurizer normal operating

pressure is 2250 psia, corresponding to a saturated temperature of 653°F. The minimum values of T_{hot} and T_{cold} from the cases in LAR Section 2.0 are used in the evaluation of the pressurizer. The NSSS design transients in LAR Section 3.0 are also applicable to the pressurizer and were considered in the analysis.

5.6.2 RESULTS

10 CFR establishes the fundamental regulatory requirements with respect to the integrity of the pressurizer components. 10 CFR 50.55a and 10 CFR 50 Appendix A General Design Criteria 1, 2, 4, 14, and 15 define the requirements of the reactor coolant pressure boundary with respect to structural and leakage integrity. Based on the following, the pressurizer components will continue to meet these requirements at SPU conditions.

The input parameters associated with the Seabrook Station SPU were reviewed and compared to the design inputs considered in the current pressurizer stress report. The ASME Boiler and Pressure Vessel Code allowable limits were maintained, since the change in the ΔT_{hot} and ΔT_{cold} was minimal and bounded by the original design basis, as defined by Seabrook Station UFSAR Section 5.4.10.1.

Since the changes in operating temperatures were small, it was not necessary to perform any detailed analysis of the pressurizer components. The design basis analysis for the Seabrook Station pressurizer surge nozzle did however, originally show the cumulative fatigue usage factor to be close to 1.0 prior to consideration of the SPU conditions. For the surge nozzle, a comparative evaluation was performed utilizing stress and fatigue results from another unit having essentially the same pressurizer design. The comparison identified significant conservatisms in the method used for design transient combinations for Seabrook Station. By adopting the evaluation from the comparison unit, it was demonstrated that the more accurate analytical effort resulted in acceptable fatigue usage for operating conditions which envelop the Seabrook Station SPU conditions.

5.6.3 CONCLUSIONS

The Seabrook Station pressurizer components meet the stress / fatigue analysis requirement of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition through Summer 1973 Addenda [Reference 5.7-1] for plant operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

5.7 STEAM GENERATORS

The Seabrook Station Model F steam generators have been evaluated for operation at the SPU conditions (LAR Section 2.0) The steam generator evaluations included an NSSS power of 3678 MWt, steam generator tube plugging in the range from 0 to 10 percent, and considered a primary average temperature (T_{avg}) window (589.1°F to 571.0°F) as well as a feed water temperature (T_{fw}) window (452.4°F to 390°F). Any steam generator design transients that were affected by analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) were addressed in the evaluations.

10 CFR establishes the fundamental regulatory requirements with respect to the integrity of the steam generator tubing. 10 CFR 50.55a and 10 CFR 50 Appendix A General Design Criteria 1, 2, 4, 14, 15, 30, 31, and 32 define the requirements of the reactor coolant pressure boundary with respect to structural and leakage integrity. Steam generator tubing and tube repairs constitute a major fraction of the reactor coolant pressure boundary. 10 CFR 50 Appendix B establishes the quality assurance requirements for the design construction, and operation of safety-related components. General Design Criteria 19 defines the requirements for radiation protection of operators working in the control room. 10 CFR 50.67 establishes reactor siting criteria, particularly with respect to exposure from the release of radioactive fission products. Based on the following evaluations, it is concluded that through meeting the acceptance criteria discussed on the various subsections below, the reactor coolant pressure boundary will continue to meet the necessary regulatory requirements at SPU conditions.

5.7.1 STEAM GENERATOR THERMAL-HYDRAULIC EVALUATION

5.7.1.1 INTRODUCTION

The Seabrook Model F steam generators were analyzed at the SPU condition for thermal-hydraulic performance (including moisture carryover and margin to local tube wall dryout), structural integrity, tube vibration (including flow-induced vibration), fatigue and wear, hardware changes and additions (repair hardware), loose parts, and tube integrity. The evaluation concluded that the Model F steam generators will support operation at the SPU conditions. Detailed discussions regarding the evaluations and the conclusions reached for each aspect of steam generator operation are included in specific subsections below.

5.7.1.2 INPUT PARAMETERS AND ASSUMPTIONS

5.7.1.2.1 OPERATING CONDITIONS

The reference case for this evaluation was established as the 100% power case (nominal 3425 MWt NSSS power). The operating conditions, except the blowdown flow rate and water level, are obtained from LAR Section 2.0 parameters for the steam generator. The bulk of the analyses assumed no steam generator blowdown as it results in slightly higher steam flow rate which is conservative for moisture carryover prediction. The blowdown flow rate may vary from 0 – 100 gpm. The total

steam generator pressure drop increases slightly with blowdown flow rate and was calculated separately assuming a 100 gpm blowdown. Other thermal-hydraulic performance characteristics do not vary significantly with the blowdown flow.

This evaluation is based on a nominal water level of 50% narrow range span. The SPU design parameters are defined in LAR Section 2.0. Steam generator outlet temperatures shown in LAR Section 2.0 are used as input in the thermal-hydraulic evaluations.

5.7.1.2.2 ASSUMPTIONS

The Seabrook Station has Model F steam generators with an as-built moisture separation system. Based on data from Seabrook Station and other plants, moisture carryover data available from steam generators with as-built moisture separator packages similar to the Seabrook Station Model F steam generators was assumed to apply to the Seabrook Station Model F steam generators.

5.7.1.3 DESCRIPTION OF ANALYSIS AND EVALUATION

Secondary side thermal-hydraulic characteristics were calculated at both the nominal and SPU conditions. A three-dimensional flow field analysis for the secondary side of the steam generator was also performed to examine the potential for local tube wall dryout.

Method Discussion

Steady-state steam generator characteristics, such as primary temperatures, circulation ratio, steam flow rate, steam pressure, secondary side pressure drop, secondary fluid inventory and damping factor were calculated. These results were then used to evaluate acceptability of steam generator performance for the SPU. The calculated operating conditions were utilized as input for evaluating margin to tube dryout and to estimate moisture carryover for the various operating conditions.

Moisture Carryover Evaluation

Excessive moisture carryover may result in erosion-corrosion problems in the steam piping and/or steam turbine. Therefore, a moisture carryover assessment was performed for the SPU conditions.

Peak Heat Flux Evaluation

Peak heat flux on the hot-leg side of the tube bundle was calculated. The subtraction of fouling resistance provided conservative results for heat flux.

Prediction of Secondary Side Mixture Quality at Departure from Nucleate Boiling

The ratio of the local secondary fluid mixture quality to the quality at departure from nucleate boiling in every flow cell of the model is considered.

5.7.1.4 ACCEPTANCE CRITERIA

The acceptance criteria for the steam generator thermal-hydraulic evaluation are as follows:

- Secondary side operating characteristics remain acceptable at the SPU conditions
- There is no local dryout on the tube wall
- Moisture carryover remains below the limit of at which erosion / corrosion of downstream piping for the steam generators is of concern, which is 0.5%
- The damping factor for the hydrodynamic instability evaluation is negative
- Changes in primary and secondary fluid mass and heat content are small (10% or less)

5.7.1.5 RESULTS

This following is a summary of the results of the Seabrook Station Model F steam generators at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level):

- The bundle flow rates for the SPU conditions are sufficiently large to prevent significant sludge accumulation or local concentration buildup; the secondary fluid velocities are about 10% higher at the SPU conditions.
- For operation at SPU conditions, the secondary fluid velocities in the U-bend region are predicted to increase from 10% to a maximum of 30% at the upper bound operating conditions. At the most likely operating point, with a Reactor Coolant System high T_{avg} of 589.1°F, and 0% steam generator tube plugging, the increase in fluid velocity is estimated to increase only 11%. The effect of increased fluid velocity on the U-bend wear has been evaluated and reported in LAR Subsection 5.7.5.4.2.
- The damping factor is sufficiently negative to assure hydrodynamic stability for the cases; therefore, the Seabrook Station steam generators will continue to operate in a hydrodynamically stable manner when operating at the SPU conditions.
- The calculated secondary side pressure drop from the feedwater nozzle inlet to the steam nozzle outlet increased by 5.5 psi; a change in pressure drop of this magnitude would have no significant effect on feedwater system operation.
- The thermal-hydraulic parameters are within acceptable ranges for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) with tube plugging levels up to 10%.
- The Seabrook Station steam generators have sufficient departure from nucleate boiling margin for the analyzed conditions and, therefore, are not expected to experience local dryout on any tube wall.
- Moisture carryover remains below the design limit of 0.25% for the cases with T_{avg} at 589.1°F. Higher moisture carryover will occur at lower T_{avg} conditions, but in all cases, the moisture carryover remains well below 0.5%, which is the

threshold for erosion / corrosion for the piping downstream of the steam generators.

- Changes in primary and secondary fluid mass and heat content is less than 10%.

5.7.1.6 CONCLUSIONS

Based upon the results of the thermal-hydraulic evaluation performed for the Seabrook Station Model F steam generators at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) which demonstrate that the acceptance criteria are met, operation at the SPU conditions with steam generator tube plugging up to 10% is acceptable for steam generator thermal-hydraulic performance.

5.7.2 STEAM GENERATOR STRUCTURAL

The steam generator structural evaluation for the SPU focuses on the critical steam generator components at the analyzed SPU core power level of 3659 (3678 MWt NSSS power level). The critical components are those which are currently the most highly stressed, or have the highest cumulative fatigue usage factors, for the present operating 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 are evaluated:

- Divider plate
- Tubesheet and shell junction
- Tube-to-tubesheet weld
- Tubes

The critical secondary side components to be evaluated include:

- Feedwater nozzle
- Secondary manway bolts
- Steam nozzle

Comparisons of the primary-side transients and Reactor Coolant System design parameters are performed to determine the scale factors that are to be applied to the baseline analyses maximum stress ranges and fatigue usage factors. The scale factors are applied to the baseline analysis results for various components to obtain the values for the analyzed 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 for each operating and transient condition are calculated based on the ratio of the primary-to-secondary-side differential pressures for the baseline condition to the differential pressure for the SPU conditions. The scale factors based on the differential pressures envelope scale factors that would be calculated based on the change in temperatures.

The scale factors (differential pressure for the SPU/ reference differential pressure) based on pressure are conservatively applied to the stress ranges which are a combination of both thermal and pressure loadings. The revised stress ranges are then used to calculate the cumulative fatigue usage.

For the secondary-side components, such as the steam nozzle and secondary manway bolts, the decrease in secondary-side pressure is the basis for a scale factor. The reduced secondary-side 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.

In the case of the feedwater nozzles, it was necessary to also include an increase in thermal stresses to account for the lower end of the feedwater temperature range analyzed. The change in feedwater temperature does not have any significant impact in the stresses on the other secondary side components being evaluated.

5.7.2.1 INPUT PARAMETERS AND ASSUMPTIONS

This structural evaluation is performed for an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and 0% to 10% steam generator tube plugging. The applicable design operating parameters used for the steam generator structural evaluation are shown in LAR Section 2.0. The Design transients, (LAR Section 3.0), and the results of the steam generator primary side to secondary side differential pressure calculation (discussed in LAR Section 5.7.3), are used to generate primary side component scale factors for each transient condition with respect to the design basis stress report results. The scale factor for secondary side components is based on the steam temperature of 517.8°F, corresponding to an analyzed minimum steam pressure of 797 psia.

An additional scale factor to account for the increased feedwater temperature range is also applied to the feedwater nozzle thermal stresses.

The SPU operating conditions provide for both a Low T_{avg} temperature operating condition case and a High T_{avg} temperature operating condition. The Low T_{avg} case results in a lower steam pressure (and therefore a greater primary side to secondary side ΔP) and as such will envelop the High T_{avg} case. On this basis the scale factors based on Low T_{avg} are used to perform a bounding evaluation of the critical primary and secondary side components.

The scale factors calculated based on the differential pressure are applied conservatively on the primary side critical component stress intensities which 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.

5.7.2.2 DESCRIPTION OF ANALYSES AND EVALUATIONS

This structural evaluation is performed for the bounding condition for the Low T_{avg} case where secondary side pressure (P_{stm}) = 797 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 factors are based on the change in the primary to secondary side differential pressure for each design transient condition and are calculated based on the following equation:

$$\frac{\Delta P_{uprate}}{\Delta P_{Nloop}} = \frac{(P_{pri} - P_{stm})_{uprate}}{(P_{pri} - P_{stm})_{Nloop}}$$

P_{pri} = *Primary side pressure (psig)*

P_{stm} = *Secondary side pressure (psig)*

ΔP_{uprate} = *Pressure Differential at SPU Conditions*

ΔP_{Nloop} = *Pressure Differential at Original Design Basis Conditions (2235 psig - 985 psig)*

Secondary side components:

Stresses in secondary side components such as the steam nozzles and secondary manway bolts, are primarily a function of only the steam pressure. For the SPU conditions, the secondary side pressure is decreased, which results in an increase in the stress range on the components. The increase in stress range may be conservatively estimated by the addition of the stress from an additional 203 psi of pressure, which is the difference from the current design basis secondary pressure (1000 psia) to the SPU secondary pressure (797 psia) for the Low T_{avg} operating condition.

For the feedwater nozzles only, since the proposed SPU conditions include the addition of a feedwater temperature range, an increase in thermal stresses must also be considered. For the analyzed SPU operating conditions, the feedwater temperature is allowed to vary between 390°F and 452.4°F. To account for stresses due to the increased temperature range, a temperature scale factor is calculated based on the change in temperature difference between feedwater temperature (T_{feed}) and the secondary side steam temperature (T_{steam}). The increase in thermal stress is incorporated into the cumulative fatigue usage factor. The change in feedwater temperature has a minimal effect on the other secondary side component stresses, and any increase in stress or fatigue usage would be negligible and need not be considered.

The calculated scale factors/added pressure loads are applied to the stress ranges for the applicable transient combinations considered in the original stress reports. 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.

5.7.2.3 ACCEPTANCE CRITERIA

The acceptance criteria for each component is consistent with the criteria used in the design basis analysis referenced for that component. The maximum range of primary-plus-secondary stresses is compared with the corresponding $3S_m$ limits in Reference 5.7-1. For situations where these limits are exceeded, the rules for plastic analysis, or simplified elastic-plastic analysis, per Section III, Subsection NB-3228 of the ASME Boiler and Pressure Vessel Code [Reference 5.7-1] are applied, consistent with the original design basis.

A cumulative fatigue usage factor less than or equal to 1.0 demonstrates the adequacy for a 40 year design life.

5.7.2.4 RESULTS AND CONCLUSIONS

The results of the evaluation demonstrate that the critical steam generator components analyzed meet the limits of Section III of the ASME Boiler and Pressure Vessel Code. The change in operating conditions will require that the secondary manway bolts be replaced after 18 years instead of the present 20 year replacement interval in order to ensure fatigue usage is less than 1.0 for the entire T_{avg} range. Results of the structural evaluation are summarized in LAR Table 5.7.2-1. (Note: Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.)

5.7.3 STEAM GENERATOR DESIGN PRESSURE

5.7.3.1 EVALUATION OF THE DESIGN PRESSURE REQUIREMENTS

An analysis was performed to determine if the limits of Section III of the ASME Boiler and Pressure Vessel Code (1971, Summer 1973 Addenda) on design primary-to-secondary pressure drop (ΔP) are satisfied for the applicable transient conditions for the Seabrook Station SPU. The design pressure limit for primary-to-secondary pressure differential is 1600 psi as defined in Model F Steam Generator Design Specification.

Based on a review of Reference 5.7-1, the normal / upset transient conditions for the Seabrook Station steam generators are subject to the following design pressure requirements.

Normal Condition Transients: Primary-to-secondary pressure gradient shall be less than the design limit of 1600 psi.

Upset Condition Transient: If the pressure differential during an upset transient exceeds the design pressure limit, the stress limits corresponding to design conditions apply using an allowable stress intensity factor of 110% of those defined Design Conditions. In other words, so long as the Upset Condition pressure values are less than 110% of the design pressure values, no additional analysis is necessary. For the Seabrook Station steam generators, 110% of the design pressure differential limit corresponds to 1760 psi.

The design pressure evaluation is based on the transient parameters described in LAR Section 3.1. Two sets of transient parameters are defined, one corresponding to a High T_{avg} mode of operation and one corresponding to a Low T_{avg} mode of operation. The pressure differentials across the primary-to-secondary side pressure boundary are calculated for the High T_{avg} and Low T_{avg} full power conditions corresponding to the 10% tube plugging level, which bounds the 0% tube plugging level.

5.7.3.2 RESULTS

The analysis determined that the maximum primary-to-secondary differential pressures during normal operating condition transients are 1442 psi and 1535 psi for the High T_{avg} and Low T_{avg} operating modes, respectively. Both of these pressures are below their design pressure differential limit of 1600 psi. The analysis also determined that the maximum primary-to-secondary differential pressures during upset condition transients are 1563 psi and 1675 psi for the High T_{avg} and Low T_{avg} operating modes, respectively. Both of these pressures are below the design pressure differential limit of 1760 psi.

5.7.3.3 CONCLUSIONS

The results of the analysis demonstrate that the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) is acceptable in terms of the structural acceptability of the primary-to-secondary pressure differentials for both the High T_{avg} and Low T_{avg} modes of operation.

5.7.4 STEAM GENERATOR HARDWARE EVALUATION

Evaluations were performed to determine the impact of the SPU conditions on the steam generator repair hardware structural evaluations, which consist of:

- Tube mechanical plugs
- Weld plugs (shop and field welded)
- Tube end machining
- Stabilizers
- Cut tube remnant evaluations
- Significant dispositioned non-conforming conditions

These hardware repairs are either already installed or are licensed to be installed in the Seabrook Station steam generators.

5.7.4.1 INPUT PARAMETERS AND ASSUMPTIONS

For the steam generator hardware evaluations, both high and low T_{avg} were considered. For both the tube mechanical plugs and the weld plugs, the enveloping condition is the one that results in the largest pressure differential between the primary and secondary sides of the steam generator. Both of the parameter

changes and the NSSS transients (LAR Section 3.0) have been used to determine the impact of the analyzed conditions on the hardware repairs.

5.7.4.2 DESCRIPTION OF THE EVALUATIONS

The structural evaluations for the steam generator hardware changes were used as a basis to justify operation at the SPU conditions. The evaluations were performed to the applicable requirements of Section III of the ASME Boiler and Pressure Vessel Code unless otherwise noted.

5.7.4.3 ACCEPTANCE CRITERIA

The tube mechanical plugs, the weld plugs, and tube ending machining were evaluated for the effects of changes due to thermal transients at the SPU conditions. The primary stresses due to design, emergency, faulted and test conditions remain within the respective allowable values of Section III of the ASME Boiler and Pressure Vessel Code. The maximum ranges of primary plus secondary stresses were compared to the corresponding 3 S_m limits. The cumulative fatigue usage factor will remain less than or equal to unity, thereby demonstrating adequacy for cyclic operation over a 40 year design life.

For the stabilizer designs, 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 adjacent tubes.

The criteria used to determine acceptability of the cut tube remnants are:

- Tubes remain stable with respect to fluid-elastic excitation.
- The turbulence induced displacements are sufficiently low as to not result tube-to-tube contact.

The criteria used to determine acceptability of the worn tubes at the fifth tube support plate are:

- Tubes remain stable with respect to fluid-elastic excitation.
- The turbulence induced stress at the degraded location is sufficiently low as to not result in fatigue crack propagation.

The methodology for foreign object evaluation is to calculate the impact-sliding wear time for the object to cause detectable wear on the tube and to compare this time to the time between plant refueling outages (cycle time). If the wear time to the tube minimum allowable wall thickness based upon Regulatory Guide 1.121 requirements (LAR Section 5.7.6) exceeds cycle time, the condition is considered acceptable.

5.7.4.4 RESULTS

A summary of the results for each of the repairs follows:

5.7.4.4.1 STEAM GENERATOR TUBE MECHANICAL PLUG

The stress/allowable ratios are less than unity at the SPU conditions, indicating that the 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 Subsection NB-3222.4 of Section III of the ASME Boiler and Pressure Vessel Code [Reference 5.7-1]. Additionally, adequate preload and friction are available to prevent dislodging of the plug for the limiting steady-state and transient loads.

5.7.4.4.2 STEAM GENERATOR TUBE SHOP AND FIELD WELD PLUGS

The field weld plugs installed in the Seabrook Station steam generators are shown to be adequate for the SPU conditions. The primary stress analysis has been reviewed, and the stress/allowable ratios are less than unity, indicating that the primary stress limits are satisfied for the weld between the weld plug and tube-sheet cladding. The cumulative fatigue usage factor for the analyzed conditions is calculated to be less than unity, thereby demonstrating adequacy for cyclic operation over a 40 year design life.

5.7.4.4.3 TUBE UNDERCUT QUALIFICATION

Steam generator tube ends may require field machining for modification or repair of tubes (i.e., plugging, sleeving, and tube end reopening). A portion of the tube and weld material could potentially be required to be removed by a machining process (drilling and reaming) in connection with Westinghouse mechanical plug removal. The evaluation performed for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) addresses the acceptability of a 0.008 inch of tube wall thickness undercut.

The approach for the Seabrook Station tube end evaluation is to utilize the results from a previous evaluation of Model F steam generators and adjust the stress values as appropriate for design transient changes for the Seabrook Station SPU. The adjustment value is conservatively based on the increase in a differential pressure for the analyzed SPU conditions across the tube sheet. The results demonstrate that the revised stresses are within allowable values of Section III of the ASME Boiler and Pressure Vessel Code. The maximum amount of tube wall material removed (0.008 inches), was analyzed and acceptable stress results were obtained.

A similar approach, using stress factors based on increased pressure differentials, is taken in the investigation of fatigue for the tube undercut machining. The evaluation shows that fatigue usage values, when adjusted for the SPU conditions, remain acceptable.

5.7.4.4.4 COLLAR CABLE STABILIZER ASSESSMENT

The qualification method employed is to show that the wall of an assumed hypothetical fully severed host tube, will wear out before the stabilizer collar, 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 will remain intact

and protected by the collar remnant for the life of the installation. Also, potentially deleterious contact with adjacent active tubes is found not to occur.

The qualification of the collar cable stabilizer is 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 with the stabilizer collar, the tube wall essentially is shown to 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 is found not to occur.

The evaluation of the straight leg collar-cable tube stabilizer installed within the Seabrook Station steam generator tube demonstrates that the above acceptance criteria are met and that stabilizer is acceptable for operation at SPU conditions.

5.7.4.4.5 CUT TUBE REMNANT EVALUATIONS

During the 2002 refueling outage, portions of several tubes were removed for examination purposes. An analysis was performed to address the section of tube that remained in steam generator D after cutting and removing the straight leg piece. With changes in secondary side operating conditions there is a potential that additional flow induced vibration effects could produce unacceptable levels of vibration and tube wear at the tube support plate locations for these tube remnants. Should significant levels of wear occur at these locations, it would be possible that a cantilevered tube would develop vibration of an amplitude that could begin to contact a neighboring tube, produce wear, and potentially result in a leaking tube. In order to determine the potential for this occurrence, an analysis was performed to determine if the changes in secondary side operating conditions would be sufficient to result in significant tube wear rate changes.

Results of the analysis indicate that with operation at the most limiting SPU condition the tubes will remain stable with respect to fluid-elastic excitation, and that the turbulence induced stresses are sufficiently low that crack propagation will not occur. As a result, these tubes will not require installation of stabilizers prior to operation of the steam generators since the tubes have been shown to remain intact and will not contact any adjacent active tubes. The analysis has determined that the tube remnants that remain in the steam generator will not experience significant flow induced vibration and will not contact any adjacent neighboring tubes with operation at SPU conditions. Based upon this finding it is not necessary to perform any additional procedures such as tube expansion in any tube support plate.

5.7.4.4.6 SIGNIFICANT DISPOSITIONED NON-CONFORMING CONDITIONS

<u>Loose Part Wear Near Tube Support Plate 5 in Steam Generator C</u>

During a previous inspection it was determined that two cold leg steam generator tubes became degraded as a result of loose part. An analysis was performed to determine if the modified operating conditions could result in additional degradation of the tubes.

Results of the analysis indicate that with operation at the SPU conditions the tubes will remain stable with respect to fluid-elastic excitation, and that the turbulence induced stresses are sufficiently low that crack propagation will not occur at the wear site. As a result, these tubes will not require installation of stabilizers prior to operation of the steam generators at the SPU conditions since the tubes have been shown to remain intact and will not contact any adjacent active tubes. Additionally, previous calculations addressing the loose part remain valid for SPU conditions. The cycle time is acceptable and will be evaluated on a cycle-by-cycle basis for future operation where tube wear is present.

Loose Parts Evaluation in Steam Generator B

Evaluations to address the loose part in steam generator B show that the object can remain in the steam generator at the SPU conditions. The loose part will be evaluated on a cycle-by-cycle basis for future operation if tube wear is present.

5.7.4.5 CONCLUSION

Results of the analyses performed on the Seabrook Station steam generator repairs or nonconforming conditions show that the applicable acceptance criteria are met at the SPU conditions.

5.7.5 TUBE VIBRATION AND WEAR

The impact of the proposed SPU on the steam generator tubes is evaluated based on the current design basis analysis, and includes 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 stability ratio and amplitudes of tube vibration due to turbulence are addressed. In addition, the effects of the SPU on potential future tube wear are also considered.

5.7.5.1 INPUT PARAMETERS AND ASSUMPTIONS

The baseline vibration analysis has been updated to reflect the SPU conditions (LAR Section 2.0), based on the updated secondary side thermal-hydraulic conditions determined by the analysis discussed previously in LAR Subsection 5.7.1. Previously established values of fluid-elastic stability, turbulent amplitudes of vibration, and tube wear are updated to incorporate the new operating parameters.

5.7.5.2 DESCRIPTION OF ANALYSES AND EVALUATIONS

The results of the current design basis vibration and wear analysis were modified to account for anticipated changes in secondary side thermal-hydraulic operating conditions due to the SPU conditions. Previously established values of fluid-elastic instability, turbulent amplitudes of vibration, and tube wear were modified to incorporate the new operating parameters.

5.7.5.3 ACCEPTANCE CRITERIA

The acceptance criteria consist of demonstrating that the tube wear rate will not result in unacceptable tube wall loss in excess of NEI 97-06, Revision 1 tube integrity and leak tightness requirements during the steam generator operating life. Also tube stresses and tube fatigue due to flow induced vibration will not exceed Section III of the ASME Boiler and Pressure Vessel Code requirements.

5.7.5.4 RESULTS

5.7.5.4.1 FLOW INDUCED VIBRATION MECHANISMS EVALUATION

For the expected tube support conditions it was determined that the straight leg stability ratios are not significantly impacted by the change in power level. However, the stability ratio for U-bend conditions increases from [ ] to [ ]. (Note: This information is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.) This is still less than the allowable limit of 1.0. On this basis it is concluded that large amplitudes of vibration are not projected to occur due to the fluid-elastic mechanism while operating the steam generator at the SPU conditions.

The maximum displacement values calculated for turbulence excitation in the original analysis are updated to account for the SPU operating conditions. For the most limiting tube support condition, the turbulence induced displacement may increase to 0.002-inches. Displacements of this magnitude are not sufficient to produce tube-to-tube contact.

As in the original analysis, the vortex shedding mechanism is shown to not be a significant contributor to tube vibration at the SPU power conditions.

Fatigue usage associated with general flow induced vibration from the most limiting SPU condition was evaluated for the Seabrook Station steam generators. In the baseline, the limiting tube exhibited a maximum flow induced vibration induced tube bending stress of < 0.1 ksi. Conservative calculations indicate that when this tube is in operation at the SPU conditions, the corresponding maximum stress level would be < 0.2 ksi. This level of stress remains well below the endurance limit of ~ 20 ksi at 1E11 cycles. The fatigue usage factor associated with flow induced vibration induced loadings while operating at the SPU power level is negligible, and fatigue degradation as a result of flow induced vibration is not anticipated at the analyzed SPU operating conditions.

In some 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 upper most plate. However, since the Seabrook Station steam generator tube support plates are manufactured from stainless steel, there is no potential for the necessary boundary conditions (i.e. denting) to occur at the uppermost support plate. High cycle fatigue of tubes in the U-bend region is not an issue for the Seabrook Station steam generators.

5.7.5.4.2 TUBE WEAR ASSESSMENT

The original design basis analysis considered the potential for tube wear in both the straight leg and U-bend portions of tubes. These design basis calculations have been updated to reflect operation of the steam generators at the SPU conditions. The updated calculation shows that the predicted depth of tube wear that may occur would increase from 0.0032 inches to ~ 0.005 inches based on a 40-year plant life cycle. From these calculations it may be concluded that although there may be an increase in the level of wear that would occur at the SPU 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.

Anti-vibration bar wear growth rates based on refueling outage 09 (October 2003) inspection of the Seabrook Station steam generators identified a maximum 95% cumulative growth rate of 5.3%. Operation of the steam generators at the most bounding conditions evaluated would result in a predicted increase in wear rate of approximately 56%. Conservatively increasing this growth rate by 56% to a growth rate of 8.3% does not represent an unacceptable growth rate which would require any modification to the current tube inspection interval. At the most likely operating point, with a Reactor Coolant System high T_{avg} of 581°F, and 0% steam generator tube plugging, the predicted increase in wear rate would be approximately 18.5%. Therefore, the SPU effects are adequately addressed in the current plant steam generator inspection plan.

5.7.5.5 CONCLUSIONS

The analysis of the Seabrook Station Model F steam generators indicates that significant levels of tube vibration will not occur from the fluid-elastic, vortex shedding, or turbulent mechanisms as a result of operation at the SPU conditions. Also, the projected level of tube wear as a result of vibration will remain small and will not result in unacceptable tube wear.

Fatigue of the tubes in the U-bend region is not a concern for the Seabrook Station steam generators since the design and materials preclude the development of the conditions necessary (i.e. denting) to initiate the type of vibration that results in the type of tube fatigue degradation that has been observed in other units.

5.7.6 TUBE REPAIR LIMITS (REGULATORY GUIDE 1.121 ANALYSIS)

The heat transfer area of steam generators in a pressurized-water reactor 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 condition loadings in accordance with Section III of the ASME Boiler and Pressure Vessel 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 provided defined stress and leakage limits are satisfied. The prescribed structural limit is adjusted to take into account possible uncertainties in the eddy current inspection, and an operational allowance is made for continued tube degradation until the next scheduled inspection.

The NRC Regulatory Guide 1.121 describes an acceptable method for establishing the limiting safe condition of degradation in the tubes beyond which tubes found defective by the established in-service inspection should be removed from service. The level of acceptable degradation is referred to as the "repair limit."

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 the flaw types occurring in the field. The allowed tube repair limit, in accordance with Regulatory Guide 1.121, is obtained by incorporating into the structural limit a growth allowance for continued operation until the next scheduled inspection, as well as an allowance for eddy current measurement uncertainty. 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 a limited axial extent at the tube support plate and anti-vibration bar intersections.

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 LAR Table 5.7.6-1. (Note: Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter No.04-017.) Each of the tube structural limits is governed by maintaining a factor of safety of 3 against burst under normal steady state full power operation at the SPU conditions. The corresponding repair limit is established by subtracting an allowance for eddy current uncertainty and continued growth from the values included in LAR Table 5.7.6-1. A margin of greater than 15% wall loss exists above the tube repair limit of 40% as defined in the Seabrook Technical Specifications based on the limiting location for localized tube wall thinning.

5.7.7 STEAM GENERATOR TUBE INTEGRITY CONSIDERATIONS

When conditions change in steam generators due to an increase in power output of a pressurized water reactor nuclear power plant, steam generator tube integrity must be addressed. Over a period of time, some tubes may become degraded locally under the influence of the operating loads and chemical environment in the steam generators. Degradation mechanisms observed in the first generation steam generators (e.g., those using mill annealed Alloy 600 tubing) included outside diameter stress corrosion cracking, primary water stress corrosion cracking, and pitting. Localized tube degradation due to wear at anti-vibration bars and tube support plates as a result of tube vibration could potentially allow for these

degradation mechanisms to affect the Seabrook Station steam generators as a result of the SPU conditions.

5.7.7.1 INPUT PARAMETERS AND ASSUMPTIONS

Parameters for the SPU analysis are provided in LAR Section 2.0 and list vessel outlet temperature (T_{hot}) as a minimum of 604.3°F and as maximum of 621.4°F. In addition to the reactor vessel outlet temperature, changes in reactor coolant and steam flows and steam generator feedwater temperatures are also listed in LAR Section 2.0.

5.7.7.2 DESCRIPTION OF ANALYSIS AND EVALUATION

The potential for localized steam generator tube wall degradation in the Seabrook Station steam generators at the SPU conditions is evaluated from a materials and steam generator water chemistry perspective through comparison with existing studies.

5.7.7.3 ACCEPTANCE CRITERIA

Steam generator tube integrity shall remain consistent with the performance criteria of NEI 97-06, Rev. 1, "Steam Generator Program Guidelines".

5.7.7.4 RESULTS

5.7.7.4.1 MATERIAL CONSIDERATIONS

Seabrook Station steam generators are Model F, vertical shell inverted U-tube evaporators, with thermally treated Inconel-600 (A600TT) tubes and stainless steel quatrefoil (four-lobe-shaped) broached hole tube support plates. The tubes were full depth hydraulically expanded into the tube-to-tubesheet crevice. Hydraulic expansion of the tubes in the tubesheet region results in reduced residual stresses compared to mechanical roll expansion, and more uniform expansion compared to explosively expanded tubes. The broached tube support plates result in reduced potential for contaminant concentration at tube support plates intersections by reducing the crevice area. The U-bend region of the tubes in rows 1 through 10 were also subjected to supplemental thermal treatment to reduce residual stresses. Materials selection and design features are intended to minimize steam generator materials corrosion and its consequences.

Stress corrosion cracking of steam generator tubing has been the major tube degradation concern in recent years. Stress corrosion cracking has occurred on both the primary side (primary water stress corrosion cracking) and on the secondary side (outside diameter stress corrosion cracking) at the top of the tube sheet and at intersections between the tube and tube support plates. The Alloy 600TT tubes in the Seabrook Station steam generators provide excellent protection against stress corrosion cracking.

Stress corrosion cracking of Alloy 600 steam generator tubing is believed to follow an Arrhenius relationship and the potential temperature increase of the steam generator

tubing has been reviewed. The slight increase of maximum temperatures in the steam generator (T_{hot}) used for this analysis suggests a slight increase for the propensity for development of stress corrosion cracking in comparison to the current parameters if the plant is operated at or near the analyzed maximum reactor vessel outlet temperature listed in LAR Section 2.0.

Thermally treated Alloy 600 is highly resistant to stress corrosion cracking. Extensive laboratory studies show impressive corrosion performance of Alloy 600 TT which is confirmed by operating experience of steam generators tubes with thermally treated Alloy 600. The highest design reactor outlet temperature for the Seabrook Station SPU is 621.4°F, assuming reduced Reactor Coolant System flow and 10% tube plugging, compared to the current 618.2°F. An extremely conservative methodology was used to estimate the additional tube degradation due to the increased reactor outlet temperature. This calculation predicted an increased degradation rate of approximately 13% over the degradation potential for the current 618.2°F T_{hot} design operating temperature. Conservatism in this methodology was demonstrated by testing and examining the influence of temperature on Alloy 600 thermally treated tube degradation. Degradation predicted for end of life for Model F steam generators is low and thus the potential additional degradation due to the SPU conditions is not expected to be significant. Therefore, the tube degradation due to the increased reactor outlet temperature at SPU conditions is not expected to be significant. At the expected SPU operating conditions for Seabrook Station, t_{hot} will be on the order of 619°F and degradation will be less than predicted.

5.7.7.4.2 CHEMISTRY CONSIDERATIONS

The integrity of Seabrook steam generator tubing (thermally treated Alloy 600) is dependent on the tubing material and the environment (physical and chemical) in which the tubes are operated. Only chemistry related degradation mechanisms and potential changes of those mechanisms are considered in this analysis. Mechanical degradation (i.e. vibration and wear) was previously addressed in LAR Section 5.7.5.

Steam Generator chemistry changes caused by the SPU must be considered for both the primary and secondary side of the steam generators. No significant effects on the bulk chemistry of either the primary or secondary side are expected due to operation at the SPU conditions because chemistry is controlled by plant procedures and specifications conforming to industry accepted guidelines. Chemistry will continue to be controlled by these procedures and specifications after the implementation of the SPU. Industry guidelines encompass a wide range of operating conditions to be applicable to pressurized water reactors and the Seabrook Station SPU does not violate the premise of those guidelines. Localized chemical changes may occur due to temperature changes at the steam generator tube surfaces (inside and outside). This discussion addresses the effect of chemistry changes on the steam generator tubing.

Pitting is considered a potential steam generator tube degradation mechanism at Seabrook Station. Pitting has not been observed at Seabrook Station or in other Model F steam generators. Acidic conditions at the tube surface beneath deposits,

usually with the presence of chloride or sulfate ions, are associated with pitting. A combination of condenser leaks and oxidation of the copper in the tubesheet sludge pile might result in a scenario to cause pitting. The steam generators at Seabrook Station have a low level of secondary side deposits containing a low level of copper. Continuation of the present maintenance program of a tight condenser and bulk chemistry to prevent strongly acidic conditions in the crevice or occluded areas in contact with the tube will prevent pitting after the SPU implementation.

5.7.7.5 CONCLUSIONS

Extremely conservative estimates of tube degradation at a T_{hot} value of 621.4°F indicate approximately 13% additional degradation due to stress corrosion cracking over the small amount that would normally be predicted for the life of the steam generators. Therefore, steam generator tube degradation predicted for the end of life is low and the potential for additional degradation due to SPU conditions is not significant. In addition, pitting is not expected due to operation at SPU conditions. Monitoring of tube degradation can be addressed through the steam generator tube surveillance requirements. The performance criteria of NEI 97-06, Rev. 1 will continue to be met through the completion of degradation, condition monitoring and operational assessments.

TABLE 5.7.2-1
PRIMARY AND SECONDARY SIDE COMPONENTS

Component	Load	Stress	Stress (ksi)	Stress (ksi)	Allowable Stress	Comments
	Condition	Category	Fatigue Baseline	Fatigue Uprate	Allowable Fatigue	
Primary Side Components						
Note: Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.						
Secondary Side Components						
Note: Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.						

TABLE 5.7.6-1
SUMMARY OF TUBE STRUCTURAL LIMITS
(REGULATORY GUIDE 1.121 ANALYSIS)

Location / Wear Scar Length	Parameter	Value	
		High T_{avg}	Low T_{avg}
Note: Information in this table is considered proprietary by Westinghouse and is provided in separate FPL Energy Seabrook correspondence, letter number 04-017.			

5.8 REACTOR COOLANT PUMPS AND MOTORS

The reactor coolant pumps at Seabrook Station were evaluated for the SPU in two separate areas: the structural adequacy of the pumps (LAR Subsection 5.8.1), and the acceptability of the reactor coolant pump motors (LAR Subsection 5.8.2).

5.8.1 REACTOR COOLANT PUMPS (STRUCTURAL)

5.8.1.1 INTRODUCTION AND BACKGROUND

Each Seabrook Station reactor coolant loop contains a Model 93A-1 single-stage shaft-seal pump driven by a 7000 horsepower (nameplate rating) motor. The pump is a vertical assembly consisting of (from top to bottom) the motor, the motor support stand, the seal assembly, and the hydraulic unit.

The reactor coolant pumps were evaluated to determine the impact of the SPU conditions. For the reactor coolant pumps, the intent is to demonstrate that the reactor coolant pump structural integrity is not adversely impacted by the SPU NSSS design parameters, and that this pressure boundary component continues to comply with industry codes and standards.

The reactor coolant pumps were evaluated for the Seabrook Station SPU design parameters (LAR Section 2.0), and the NSSS design transients (LAR Section 3.1), based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

5.8.1.2 INPUT PARAMETERS AND ASSUMPTIONS

The Model 93A reactor coolant pumps were originally designed and analyzed to meet the Seabrook Station reactor coolant pump design specification and Section III of the ASME Boiler and Pressure Vessel Code [Reference 5.8-1]. The current Seabrook Station SPU modifies the design operating parameters (LAR Section 2.0) and the NSSS design transients (LAR Section 3.1) that were considered in the original evaluation.

The Seabrook Station reactor coolant pumps are installed in the Reactor Coolant System cold leg, between the steam generator outlet and the reactor vessel inlet. The temperatures and pressures used as inputs to the reactor coolant pump Section III of the ASME Boiler and Pressure Vessel Code structural analysis are those defined for the reactor vessel inlet in the design operating parameters in LAR Section 2.0. The reactor coolant pumps must be evaluated for the NSSS design transients, as defined for the Reactor Coolant System cold leg by the design specification updated for the SPU.

5.8.1.3 DESCRIPTION OF ANALYSIS

The purpose of this evaluation is to demonstrate the continued applicability of the design specification and the plant specific pressure boundary evaluation, or present additional information, in order to demonstrate compliance with applicable

requirements of industry codes and standards. The critical components that are covered by this evaluation are the pump casing and feet, the bolting ring and bolts, the thermal barrier heat exchanger assembly, and the seal housings and bolts. These components are evaluated for both steady state and transient conditions. Compliance with ASME Boiler and Pressure Vessel Code requirements is used to demonstrate acceptability. The Code of Record for the Seabrook Station reactor coolant pumps is Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition with Addenda through the Summer 1973 Addenda [Reference 5.8-1].

5.8.1.3.1 OPERATING TEMPERATURE AND PRESSURE

From the SPU design parameters for Seabrook Station in LAR Section 2.0, there are no changes from the current reactor coolant pressure of 2250 psia for any of the SPU cases. The design Reactor Coolant System cold-leg temperature (T_{cold}) in LAR Table 2.3-1, defined by the vessel inlet (reactor coolant pump outlet) temperature for the SPU, is a maximum of 556.8°F. This temperature is less than the corresponding temperature considered in the original analyses, which was 558.2°F at the pump inlet and 558.8°F at the vessel inlet . The minimum vessel inlet temperature (537.7°F) is lower by 21.1°F than the temperature considered in the original analyses. Due to lower associated allowable design stress limits, higher temperatures are more limiting for the reactor coolant pump structural design qualification. Since none of the temperatures exceeds the previously considered temperatures, and since the pressure does not change, the SPU design parameters are bounded by those used as inputs to the original analyses.

5.8.1.3.2 TRANSIENT EVALUATION

The reactor coolant pump structural evaluation considers the NSSS design transients discussed in LAR Section 3.1, compared to those defined in the reactor coolant pump design specification. Only the transient variations of T_{cold} and Reactor Coolant System pressure need to be considered when comparing the transients applicable to the reactor coolant pumps.

Model 93A-1 reactor coolant pumps have been analyzed for transients similar to those specified for the Seabrook Station SPU, and these analyses were used as a basis for the evaluation of the Seabrook Station reactor coolant pumps. These analyses involve grouping the transients and then analyzing a limited number of temperature distributions that envelope each transient group.

Based on the enveloping temperatures used for the transient groups in these analyses, it was determined that no Normal or Upset Condition transients require closer examination. The only emergency operating condition transient that requires closer examination is the SBLOCA.

The SBLOCA transient is an Emergency Condition transient. The change to this transient consists of consideration of T_{cold} temperature variation for the low T_{avg} operating condition. Since the Section III, Subsection NB-3224 of the ASME Boiler and Pressure Vessel Code ASME Boiler and Pressure Vessel does not require

evaluation of secondary or peak stresses or fatigue for emergency conditions, this change in the SBLOCA has no effect on the evaluation of the reactor coolant pumps.

The original qualification of the pump was based on using a fatigue waiver, as defined in Section NB-3222.4(d) of the ASME Boiler and Pressure Vessel Code, to address fatigue for the Code pressure boundary parts of the pump. The revised calculations show that the pump casing, the thermal barrier, bolting ring and main flange bolts, and the seal housing still qualify for the fatigue waiver.

Even though the fatigue waiver conditions are satisfied for the other components of the pump, some cumulative usage factors were calculated as part of simplified elastic-plastic analyses. These analyses are performed per Section NB-3228.3 of the ASME Boiler and Pressure Vessel Code when the 3 S_m limit on the range of local primary plus secondary stress intensity is exceeded, where S_m is the allowable stress intensity defined in the ASME Boiler and Pressure Vessel Code for the material at operating temperature. The pump components where these analyses were performed are the casing and casing nozzles. The usage factors did not change due to the SPU.

5.8.1.4 ACCEPTANCE CRITERIA

The acceptance criteria for the ASME Boiler and Pressure Vessel Code structural analysis of the reactor coolant pump pressure boundary are that the analyzed stresses do not exceed the stress allowables of the ASME Boiler and Pressure Vessel Code and that the cumulative usage factors from the Code fatigue analysis remain less than 1.0. The applicable General Design Criteria are 1, 2, 4, 14, and 15.

5.8.1.5 RESULTS

The operating temperature and pressure discussion presented in LAR Subsection 5.8.1.3.1 showed that the operating pressures and temperatures are bounded by those considered for the original stress analysis.

The NSSS design transient discussion presented in LAR Subsection 5.8.1.3.2 shows that the usage factors calculated for the pump are less than the ASME Boiler and Pressure Vessel Code allowable of 1.0. A summary of the fatigue evaluation results is given in LAR Table 5.8-1.

When the SPU evaluation was performed, no increases were required in the stresses that had been determined in the previous stress analyses. This is because the stresses associated with the temperature and pressure changes considered in the original analyses bounded the stresses associated with temperature and pressure changes defined for the SPU.

5.8.1.6 CONCLUSIONS

The reactor coolant pump pressure boundary is shown to continue to comply with the requirements of the ASME Boiler and Pressure Vessel Code of record when subject to the SPU design operating parameters and NSSS design transients. Therefore, the reactor coolant pump evaluation results for the SPU are consistent with and

continue to comply with the current licensing basis/acceptance requirements for Seabrook Station, including General Design Criteria 1, 2, 4, 14, and 15.

5.8.2 REACTOR COOLANT PUMP MOTORS

5.8.2.1 INTRODUCTION AND BACKGROUND

This section addresses the performance of the reactor coolant pump motors. The reactor coolant pump motors are evaluated for the Seabrook Station SPU design operating parameters in LAR Section 2.0 and the reactor coolant loop Best-Estimate Flows, which were based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

5.8.2.2 INPUT PARAMETERS AND ASSUMPTIONS

The input parameters considered in the evaluation of the reactor coolant pump motors are the steam generator outlet temperatures (LAR Section 2.0) and the Best-Estimate Flows defined for the Seabrook Station SPU. These parameters are considered for the Seabrook Station Model 93A-1 reactor coolant pumps consisting of the original pumps and spare pump supplied to Seabrook Station.

5.8.2.3 DESCRIPTION OF ANALYSIS

The steam generator outlet temperatures and Best-Estimate Flows are considered in a hydraulic analysis using the operating characteristics of the Seabrook Station reactor coolant pumps. The pump impellers originally supplied to Seabrook Station, and the spare impeller, were considered. This hydraulic analysis calculates the power requirements for the impeller that operates at the highest cold power.

The reactor coolant pump motor loading was evaluated in four areas:

- Continuous operation at hot-loop temperatures and flows
- Continuous operation at cold-loop temperatures and flows
- Starting across the line with a minimum 80-percent starting voltage
- Loads on the thrust bearings

5.8.2.4 ACCEPTANCE CRITERIA

The acceptance criteria used for evaluating the reactor coolant pump motor loading for the Seabrook Station SPU were taken from the equipment specifications for the motor.

Per the equipment specifications, the motor is required to drive the pump continuously under hot-loop conditions without exceeding a stator winding temperature rise of 70°C. This corresponds to the National Electric Manufacturers' Association (NEMA) MG 1, Section III, Part 20.8, Class B temperature rise limit in a 50°C ambient temperature.

Per the general equipment specification, 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 without exceeding a stator winding temperature rise of 95°C. This corresponds to the NEMA guaranteed limit for a Class F winding in a 50°C ambient temperature.

Per the plant specific supplement to the equipment specification, the motor is required to start across the line with a minimum 80-percent starting voltage against the reverse flow of the other pumps running at full speed under cold-loop conditions. The limiting component for this type of loading is the rotor cage winding, which has design limits of a 300°C temperature rise on the bars and a 50°C temperature rise on the rings.

The thrust-bearing loading used for the motor design is given in the plant specific supplement to the equipment specification. Performance of the thrust bearings in a reactor coolant pump 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.

5.8.2.5 RESULTS

The worst hot condition was identified as a reactor coolant flow of 97,600 gpm/loop, which corresponds to the best estimate flow with 10% steam generator tube plugging and a steam generator outlet temperature of 537.4°F. The corresponding cold condition flow would be 91,744 gpm/loop at a temperature of 70°F. These conditions are for the Low T_{avg} case with 10% steam generator tube plugging. The maximum brake horsepower requirements were identified as 7124 brake horsepower for the hot reactor coolant condition and 9083 brake horsepower for the cold reactor coolant condition. Note that at the expected SPU operating conditions for Seabrook Station (High T_{avg} case, 0% tubes plugged, and best estimate reactor coolant flow of 100,500 gpm), the brake horsepower requirement will be 6903 horsepower. The Seabrook Station reactor coolant pump motors have a nameplate rating of 7000 horsepower for the hot reactor coolant condition and a nameplate rating of 8750 horsepower for the cold reactor coolant condition. The worst hot reactor coolant condition power requirement is 1.8% above the motor's name plate rating, and the cold reactor coolant condition power requirement exceeds the cold nameplate rating by 3.8%. Thus, additional evaluations were performed to demonstrate the acceptability of the reactor coolant pump motors. The evaluations of the reactor coolant pump motors are described in the following paragraphs.

5.8.2.5.1 CONTINUOUS OPERATION AT HOT-LOOP CONDITIONS

Per the equipment specifications the motor is required to drive the pump continuously under hot reactor coolant conditions without exceeding a stator winding temperature rise of 70°C. This corresponds to the NEMA Class B temperature rise limit in a 50°C ambient temperature.

The maximum hot reactor coolant load under the revised operating conditions is 7124 horsepower. The maximum stator temperature rise at this new load is 47.2°C. This is less than the NEMA Class B limit and is therefore acceptable.

5.8.2.5.2 CONTINUOUS OPERATION AT COLD-LOOP CONDITIONS

Per the general equipment specification the motor is required to drive the pump for up to 50 hours (continuous) and 3000 hours maximum over the 40 year design life of the plant under cold reactor coolant conditions without exceeding a stator winding temperature rise of 95°C. This corresponds to the NEMA guaranteed limit for a Class F winding in a 50°C ambient temperature. Analysis indicates that the cold reactor coolant condition temperature rise of the stator at the revised load of 9083 horsepower will be approximately 69.6°C, which is well below the NEMA limit. Therefore, cold loop operation at the revised load is acceptable.

5.8.2.5.3 STARTING

Per the plant specific supplement to the equipment specification the motor is required to start across the line with a minimum 80% starting voltage, against the reverse flow of the other pumps running at full speed, under cold loop conditions. The limiting component for this type of duty is the rotor cage winding. A conservative heat stored analysis is used to determine if the rotor cage winding temperature rise exceeds the design limits, which are 300°C on the bars and 50°C on the resistance rings. The results of this analysis show a bar temperature rise of 166.2°C and a ring temperature rise of 16.93°C. These temperatures do not exceed the design limits. Therefore, the motor can safely accelerate the load under worst case conditions.

5.8.2.5.4 THRUST-BEARING LOADING

Performance of the thrust bearings in a reactor coolant pump motor can be adversely affected by excessive or inadequate loading. The axial down thrust for the revised parameters increased from 46,000 pounds to 54,608 pounds for hot reactor coolant operation and increased from 66,000 pounds to 73,626 pounds for cold reactor coolant operation. The thrust bearings are designed for loads exceeding 109,000 pounds, so the changes in the bearing loads are considered acceptable for the revised loads.

5.8.2.6 CONCLUSIONS

The reactor coolant pump motors are evaluated in four areas for the SPU conditions under loadings of 7124 horsepower for worst-case hot-loop operation, and 9083 horsepower for worst-case cold-loop operation. The hot and cold operating conditions and the worst case starting condition temperature rises are shown to still comply with the acceptance criteria. The thrust bearing loading is shown to remain in the acceptable range for the hot and cold condition. The reactor coolant pump motors at the Seabrook Station are thus considered acceptable for the SPU.

TABLE 5.8-1
REACTOR COOLANT PUMP FATIGUE EVALUATION FOR SEABROOK STATION SPU

Reactor Coolant Pump Component	Cumulative Usage Factor
Casing	Fatigue waiver [1]
Casing feet	Fatigue waiver
Bolting ring	Fatigue waiver
Main closure bolts	Fatigue waiver
Thermal barrier heat exchanger	Fatigue waiver
Seal housing and bolts	Fatigue waiver
Suction/discharge nozzles	< 1.0

Note:

1. A usage factor was calculated for the casing in a simplified elastic-plastic analysis. This usage factor was less that the allowable value of 1.0 and did not change as a result of the SPU evaluations.

5.9 CHEMICAL AND VOLUME CONTROL SYSTEM, RESIDUAL HEAT REMOVAL SYSTEM, AND EMERGENCY CORE COOLING SYSTEM COMPONENTS

5.9.1 INTRODUCTION

The purpose of this section is to evaluate the Seabrook Station NSSS auxiliary tanks, heat exchangers, pumps and valves for the parameters associated with the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The scope of this evaluation encompasses the equipment supplied by Westinghouse for those systems that could be affected by the SPU. Specifically, the equipment was evaluated on a per system basis for impact by revised thermal transients and maximum operating temperatures and pressures. The evaluation consists of a structural review of the component pressure boundaries. The Seabrook Station NSSS Auxiliary Systems associated with this evaluation include:

- Chemical and Volume Control System
- Residual Heat Removal System
- Safety Injection System

5.9.2 INPUT PARAMETERS AND ASSUMPTIONS

The auxiliary systems tanks, heat exchangers, and pumps that were provided to Seabrook Station by Westinghouse are listed in the subsections below. Valves are evaluated per the Westinghouse valve list supplied in the original plant design. Design operating parameters provided in LAR Section 2.0 document the impact of the SPU on the NSSS system operating temperatures and pressures. This information was evaluated, as required, based on the auxiliary equipment maximum operating temperatures and pressures identified in the original equipment design specifications. The impact of transients on auxiliary tanks, heat exchangers, pumps, and valves subject to the auxiliary system transients were also evaluated based upon the SPU conditions.

5.9.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The design parameters were reviewed for the Seabrook Station NSSS auxiliary tanks, heat exchanger, pumps and valves. The specific criteria include design temperature, pressure, and thermal transients. These parameters were compared to those used in the SPU to determine if the design parameters still enveloped those for the SPU. The SPU design conditions were compared with the original design requirements to determine the acceptability of the components for the SPU conditions.

5.9.3.1 AUXILIARY SYSTEM TANKS

The NSSS auxiliary tanks provided to Seabrook Station are

- Reactor coolant pump seal standpipes (4)
- Volume control tank (1)
- Pressurizer relief tank (1)
- Safety injection accumulator tanks (4)

The only tanks that have transients identified are the safety injection accumulators. The operating temperatures and pressures for these vessels remain within the design basis for these tanks, and the thermal transients for the safety injection accumulators remain bounded by the original design transients.

5.9.3.2 AUXILIARY SYSTEM HEAT EXCHANGERS

The NSSS auxiliary heat exchangers provided to Seabrook Station are:

- Residual heat removal heat exchangers (2)
- Regenerative heat exchanger (1)
- Seal water heat exchanger (1)
- Excess letdown heat exchanger (1)
- Letdown heat exchanger (1)
- Letdown reheat heat exchanger (1)

There is no impact upon the auxiliary systems heat exchangers as a result of the SPU. The operating temperature and pressure ranges for these vessels remain bounded by the original design parameters. The original design transients for the auxiliary equipment remain bounded for the transients associated with the SPU. The heat exchangers identified in the original design specifications as having transients are the regenerative, letdown, excess letdown, letdown reheat, and residual heat removal heat exchangers. These temperatures and pressures remain bounded by the original design conditions.

5.9.3.3 AUXILIARY SYSTEM PUMPS

The NSSS auxiliary pumps that were provided to Seabrook Station are:

- Boric acid transfer pumps (2)
- Centrifugal charging pumps (including oil cooler and gear box cooler) (2)
- Positive displacement charging pump (1)
- Residual heat removal pumps (including seal cooler) (2)
- Safety injection pumps (2)

Based upon an evaluation utilizing the parameters in LAR Section 2.0, there is no impact upon the auxiliary systems pumps listed in this subsection as a result of the SPU. The operating temperature and pressure ranges for these pumps remain bounded by the original design parameters. The original design transients for the auxiliary equipment bound the transients associated with the SPU. The pumps identified in the original design specifications as having transients are the centrifugal charging pumps, positive displacement charging pump, residual heat removal pumps, and the safety injection pumps.

5.9.3.4 AUXILIARY SYSTEM VALVES

The NSSS auxiliary system valves that were provided to Seabrook Station are included in the Westinghouse valve list for Seabrook Station. Based upon the design operating parameters in LAR Section 2.0 and the NSSS and auxiliary transients for the SPU, there is no impact upon the auxiliary systems valves as a result of the SPU. The operating temperature and pressure ranges for the valves remain bounded by the original design parameters. The original design transients for the auxiliary equipment remain bounding for the transients associated with the SPU.

5.9.4 ACCEPTANCE CRITERIA

If the maximum system operating temperatures, pressures, and flow rates for the SPU are bounded by the original system design conditions, then no further effort would be required to qualify the auxiliary tanks, heat exchangers, pumps and valves for this aspect of the SPU. Any values in excess of the design values will be addressed in this report.

If the original design transients bound the revised auxiliary tanks, heat exchangers, pumps and valve transients for the SPU, then no further effort would be required to qualify the equipment for this aspect of the SPU. If the revised transients are not bounded by the original equipment design, then each affected piece of equipment would need to be re-qualified for the new transient conditions on a case-by-case basis.

5.9.5 RESULTS

A comparison of the conditions given in LAR Section 2.0 and the SPU design transients shows that the maximum operating temperatures and pressures for systems within Westinghouse scope are bounded by the existing design basis. Since the tanks, heat exchangers, pumps and valves were designed and manufactured consistent with the system design and applicable Codes and standards requirements, the Seabrook Station NSSS tanks, heat exchangers, pumps and valves are acceptable for the maximum system operating temperatures and pressures resulting from the SPU. The auxiliary equipment and NSSS thermal transients resulting from the SPU are bounded by the original Seabrook Station design parameters. Therefore the auxiliary tanks, heat exchangers, pumps and valves remain acceptable for the thermal transients resulting from the SPU.

5.9.6 CONCLUSIONS

The Seabrook Station auxiliary tanks, heat exchangers, pumps and valves are acceptable for the SPU conditions since the original design basis bounds the auxiliary systems operating conditions identified as a consequence of the SPU.

5.10 BOTTOM MOUNTED INSTRUMENTATION

5.10.1 INTRODUCTION

The In-Core Instrumentation, also known as the Bottom Mounted Instrumentation system, consists of guide tubing, flux thimbles and the seal table. The guide tubing is 1-inch outside diameter X 0.52-inch inside diameter at fifty eight (58) locations in the Seabrook Station reactor pressure vessel. The tubes are used as guide paths for the flux thimbles which run from the seal table to center instrument tubes in the fuel assemblies. The guide tubes are pressure boundary components designed to Section III of the ASME Boiler and Pressure Vessel Code, Class 1. The flux thimbles are double walled assemblies, each consisting of a 0.397-inch outside diameter outer sheath tube and a 0.201-inch outside diameter X 0.138-inch inside diameter inner calibration tube. Five self powered detectors and one thermocouple wire (.062-inch diameter) are in the annulus of each outer sheath tube and calibration tube. The self powered detectors continuously monitor the neutron flux in the reactor pressure vessel. The seal table is a rectangular plate of 8'-5-inch Length x 2'-6-inch Width x 0.375-inch Thickness, which is used as a structural support for the guide tubes at one end. It is designed to Section III Subsection NF of the ASME Boiler and Pressure Vessel Code, Class 1 requirements. The seal table is the location where one end of each guide tube is welded. The other end of each guide tube is welded to the bottom penetration nozzle of the reactor pressure vessel. The flux thimbles enter the guide tubes at the seal table, pass through the guide tubes into the reactor pressure vessel, and then into the fuel assemblies passing through the lower instrument columns of the reactor internals. The flux thimbles that enter the fuel assemblies have closed bullet ends. The pressure boundary for the guide tubing and flux thimbles is maintained by the compression fittings at the seal table.

The guide tubing along with the flux thimbles are analyzed to meet the stress requirements of Section III, Subsection NC-3650 of the ASME Boiler and Pressure Vessel Code. The stresses must meet the allowable of Equations 8, 9, 10, and 11 of Section III, Paragraph NC-3650 of the ASME Boiler and Pressure Vessel Code. The seal table was qualified to Section III, Class 1, Subsection NF requirements of the ASME Boiler and Pressure Vessel Code.

5.10.2 DESCRIPTION OF ANALYSIS AND EVALUATION

The pressure and vessel inlet temperature information from LAR Section 2.0 is compared with the current design operating conditions. Also the pressure and temperature during design transient conditions identified for the SPU is compared with the design input used in current analysis. The transient temperature effects for the Bottom Mounted Instrumentation guide tubing were not historically considered by Westinghouse due to stagnant fluid in the guide tubing annulus. Due to methodology updates, the transient effects for pressure and temperature are considered in the reconciliation of the guide tubing, considering the maximum values. Also, the reactor pressure vessel displacement during a LOCA used in the current analysis are compared with the new values generated for the Seabrook Station SPU.

The revised stresses in the guide tubing should meet the acceptance criteria given by Equations 8, 9, 10, 11, and 9 (faulted) case of Section III, Subsection NC-3650 of the ASME Boiler and Pressure Vessel Code. It is expected that the reactions at the seal table are of the same magnitude in the original analysis. If these criteria are met, the previous qualification performed for the seal table remains valid.

The flux thimble weight is considered part of the guide tubing weight in the original analysis. Hence no further qualification is needed for the flux thimble.

5.10.3 ACCEPTANCE CRITERIA

The acceptance criteria are based on a comparison of the SPU design input with the design input used previously in the qualification of guide tubing. If the evaluation of the SPU program steady state design operating conditions, design transients and vessel displacements results in stresses that are within the bounds of the current design input, no further analysis is needed. If the SPU design input values are higher than the current design input, design stresses are reconciled for SPU uprate conditions. The acceptance criteria for the allowable stress in the guide tubing are defined by Section III, Subsection NC-3650 of the ASME Boiler and Pressure Vessel Code.

5.10.4 RESULTS

The revised stresses for the SPU conditions in general increased slightly over the current stresses. The calculated stresses remained well within allowable values. The margin to ASME Boiler and Pressure Vessel Code stress allowables varied from between approximately 10% to 60%.

5.10.5 CONCLUSIONS

The evaluation of the bottom-mounted instrumentation for the SPU demonstrated that the guide tubing meets the requirements of Section III Subsection NC-3650 of the ASME Boiler and Pressure Vessel Code. Thus the design is adequate for Seabrook Station operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

5.11 MATERIALS

5.11.1 INTRODUCTION

This section summarizes the evaluations and results of an assessment of the potential materials degradation issues arising from the proposed SPU on the performance of primary component materials at Seabrook Station.

The primary concern from the proposed SPU is the potential impact of changes in the Reactor Coolant System chemistry (impurities) and pH conditions and the service temperature on the material integrity during service. These include general corrosion (wastage) and stress corrosion cracking of system materials, fuels corrosion, and primary water stress corrosion cracking of nickel base alloys. These issues are considered below. The applicable General Design Criteria are 1, 4, 14, and 31.

5.11.2 PROPOSED SERVICE CONDITIONS DUE TO SPU

A review of the SPU design documents suggests that the following Reactor Coolant System chemistry and service conditions would be expected from the SPU:

- The reactor coolant lithium/boron program is coordinated such that a pH value between 7.1 and 7.23 is maintained initially at a maximum lithium level. The lithium level is then decreased gradually as the pH value increases to a maximum value at the end of life.
- The reactor pressure vessel inlet temperature is decreased slightly, while the coolant temperature at the reactor pressure vessel outlet nozzle will be increased slightly for the SPU.

The significance of these changes in the service conditions is assessed below in reference to the materials performance.

5.11.3 MATERIALS ASSESSMENT

The impact of the proposed SPU conditions on the performance of Reactor Coolant System materials is considered below:

Austenitic Stainless Steels

The two degradation mechanisms that are operative in austenitic stainless steels are the intergranular stress corrosion cracking and transgranular stress corrosion cracking. Sensitized microstructure and the presence of oxygen are required for the occurrence of intergranular stress corrosion cracking while the introduction of halogens such as Chlorides and the presence of oxygen are prerequisites for the occurrence of transgranular stress corrosion cracking. The chemistry program for the SPU does not involve introduction of any of these contributors so that no impact on material degradation is expected in the stainless steel components as a result of the SPU.

Fuel Cladding Corrosion Effects

The Seabrook Station lithium, boron and pH management program shows that the program meets the Electric Power Research Institute chemistry guidelines. Since these guide lines are specifically designed to prevent fuel cladding corrosion effects such as fuel deposit build-up and Alloy 600 primary water stress corrosion cracking, there will be no impact on the fuel cladding corrosion effects.

Primary Water Stress Corrosion Cracking of Alloy 600/82/182 Components

The most significant factor that influences the primary water stress corrosion cracking of Alloy 600/82/182 components is the service temperature. The proposed SPU at Seabrook Station involves changes in the reactor pressure vessel inlet and outlet temperatures. In general the industry experience over the past decade showed that the primary water stress corrosion cracking susceptibility of the Alloy 600/82/182 outer most circle reactor pressure vessel head penetrations is considered bounding to other Alloy 600 primary component locations due to the presence of high residual stresses and service temperatures at the penetration locations. In the case of Seabrook Station however, the reactor pressure vessel upper head and reactor pressure vessel head penetrations are maintained at the vessel inlet temperature. Since the proposed SPU will result in a decrease in the vessel inlet temperature, the reactor pressure vessel head penetrations will see less limiting conditions than currently. The corresponding primary water stress corrosion cracking susceptibility of the reactor pressure vessel head penetrations is not likely to bound other Alloy 600 locations. There will be an increase in the service temperature of hot leg nozzle weld by 3.2°F. To ensure that the highest susceptibility Alloy 600/82/182 location is considered, the current primary water stress corrosion cracking assessment included the outermost reactor pressure vessel head penetration as well as the hot leg nozzle weld. A summary of the results of the primary water stress corrosion cracking assessment is presented below.

5.11.4 RESULTS

The assessment of the potential materials degradation issues resulting from the proposed SPU on the Seabrook Station, as described above, has yielded the following results:

- No degradation issues are identified with the internal and core support materials due to the proposed SPU.
- The primary water stress corrosion cracking susceptibility of the highest susceptible Alloy 600 control rod drive mechanism penetration is expected to decrease.
- While the primary water stress corrosion cracking susceptibility of the Alloy 82/182 hot leg nozzle weld is expected to increase, the change in susceptibility due to the SPU is insignificant.

5.11.5 CONCLUSIONS

Based upon these results, it has been concluded that the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) for the Seabrook Station is acceptable with respect to potential material degradation Issues. The primary component materials continue to comply with General Design Criteria 1, 4, 14, and 31.

5.12 APPLICATION OF LEAK-BEFORE-BREAK METHODOLOGY

The current structural design basis of Seabrook Station includes the application of Leak Before Break methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the Reactor Coolant System 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 conditions associated with the Seabrook Station analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

5.12.1 INTRODUCTION AND BACKGROUND

Westinghouse performed analyses for the Leak Before Break of Seabrook Station primary loop piping in 1984. The results of the analyses were documented in WCAP-10567 [Reference 5.12-1] and approved by the Nuclear Regulatory Commission.

To demonstrate the elimination of Reactor Coolant System 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 Reference 5.12-1.

The current Leak Before Break analyses were updated to address SPU conditions. The SPU evaluation and results are addressed below.

5.12.2 INPUT PARAMETERS AND ASSUMPTIONS

The loadings, design pressure, and design temperature parameters for the SPU were used in the evaluation. The parameters, which are important in the evaluation, are the piping forces, moments, design operating temperature, and design pressure. These parameters were used in the evaluation. The design temperature and pressure at the SPU conditions are described in LAR Section 2.0.

5.12.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The recommendations and criteria proposed in the Standard Review Plan [Reference 5.12-2] are the basis for this evaluation. The design temperature, pressure and primary loop piping dead weight, normal thermal expansion, safe shutdown earthquake and pressure loads due to the SPU Program were used in this evaluation. The evaluation showed that the Leak Before Break recommended

margins were satisfied for the SPU conditions. The margins from Reference 5.12-2 are also described below.

5.12.4 ACCEPTANCE CRITERIA AND RESULTS

The Leak Before Break acceptance criteria is based on the Nuclear Regulatory Commission Standard Review Plan 3.6.3 [Reference 5.12-2]. The recommended margins are as follows:

- Margin of 10 on leak rate
- Margin of 2.0 on flaw size
- Margin on loads of 1.0 (Using faulted load combinations by absolute summation method)

The evaluation results showed the following at the critical locations:

- Leak Rate - A margin of 10 exists between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gpm.
- Flaw size - A margin of 2.0 or more exists between the critical flaw and the flaw having a leak rate of 10 gpm (the leakage flaw).
- Loads - A margin of 1.0 on loads exists.

The evaluation results show that the Leak Before Break conclusions provided in Reference 5.12-1 for Seabrook Station remain unchanged for SPU conditions.

5.12.5 CONCLUSIONS

The Leak Before Break acceptance criteria are satisfied for the Seabrook Station primary loop piping at the SPU conditions. The recommended margins are satisfied and the conclusions shown in Reference 5.12-1 remain valid. It is, therefore, concluded that the dynamic effects of Reactor Coolant System primary loop pipe breaks need not be considered in the structural design basis of Seabrook Station at the SPU conditions.

5.13 REFERENCES

5.1-1 ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, 1971 Edition with Addenda through the Winter 1972, American Society of Mechanical Engineers, New York.

5.1-2 10 CFR 50, Appendix G & H, "Reactor Vessel Material Surveillance Program Requirements," Federal Register, Volume 60, No. 243, December 19, 1995.

5.1-3 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," Federal Register, Volume 60, No. 243, December 19, 1995.

5.1-4 ASTM Standard E853. "Analysis and Interpretation of Light Water Reactor Surveillance Results" and Regulatory Guide RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," United States Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001.

5.1-5 WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves," January 1996.

5.1-6 WCAP-15557 (non-Proprietary), "Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology," August 2000.

5.1-7 U. S. NRC Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials", May 1988.

5.1-8 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."

5.1-9 Singer, L.R., "Public Service Company of New Hampshire Seabrook Station Unit No. 1 Reactor Vessel Radiation Surveillance Program," WCAP-10110, March 1983.

5.1-10 T. Laubham, et al, "Seabrook Station Heatup and Cooldown Limit Curves for Normal Operation," WCAP-15745, December 2001.

5.1-11 License Amendment Report 02-04, "Revision to Technical Specifications associated with Pressure / Temperature Curves and Low Temperature Overpressure Protection Limits", October 11, 2002.

5.4-1 ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, 1974, with Addenda Summer 1974. Division I, Subsection NA and NB, and Appendices.

5.5-1 American Society of Mechanical Engineers Boiler & Pressure Vessel Code, Section III, Subsection NB, 1986 Edition.

5.5-2 American Society of Mechanical Engineers Boiler & Pressure Vessel Code, Section III, 1977 Edition and Addenda up to Summer 1979.

5.5-3 American Society of Mechanical Engineers Boiler & Pressure Vessel Code, Section III, Subsection NF, 1974 Edition with Summer 1974 addenda.

5.5-4 NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification", December 1988

5.7-1 ASME Boiler and Pressure Vessel Code Section III, "Rules for the Construction of Nuclear Power Plant Components," 1971 Edition, Summer 1973 Addendum, ASME, New York, New York.

5.8-1 ASME Boiler and Pressure Vessel (B&PV) Code, 1971 Edition with Addenda through the Summer 1973 Addenda, Section III, Division 1, "Nuclear Power Plant Components", Subsection NB, "Class 1 Components", The American Society of Mechanical Engineers, New York, New York.

5.12-1 WCAP-10567,"Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Seabrook Units 1 and 2," June 1984.

5.12-2 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.

SEABROOK STATION

SECTION 6.0

ACCIDENT ANALYSES

6.0 ACCIDENT ANALYSES

This section provides the results of the analyses and / or evaluations that were performed for the NSSS accident analyses in support of the Seabrook Station SPU. The accident analyses were performed at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The accident analysis areas addressed in this section include:

- Loss of coolant accidents
- Steam generator tube rupture
- Non-LOCA events
- Containment response
- Main steamline break outside containment
- Radiological consequences (doses) – Note that the radiological consequences of accidents at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) are summarized in the Alternate Source Term License Amendment Request. [Reference 6.2-6]

The detailed results and conclusions of each analysis are presented within each section below.

6.1 LOSS OF COOLANT ACCIDENTS

6.1.1 BEST-ESTIMATE LARGE BREAK LOSS OF COOLANT ACCIDENT (LOCA)

6.1.1.1 INTRODUCTION / BACKGROUND

Westinghouse has obtained generic Nuclear Regulatory Commission approval of its topical report describing best-estimate large break LOCA methodology. Nuclear Regulatory Commission approval of the methodology is documented in the Nuclear Regulatory Commission safety evaluation report appended to the topical report (WCAP-12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1), "Code Qualification Document for Best Estimate LOCA Analysis," March 1998) [Reference 6.1-1]. Plant specific analysis for Seabrook Station has been performed using the approved methodology.

These changes are being made to incorporate the best-estimate approach into the licensing basis for Seabrook Station large break LOCA analysis in accordance with 10 CFR 50.46, Regulatory Guide 1.157 "Best-Estimate Calculations of Emergency Core Cooling System Performance," and the Westinghouse "Code Qualification Document for Best Estimate LOCA Analysis," WCAP-12945-P-A, Volumes 1-5 [References 6.1-2, and 6.1-3, respectively]. The best-estimate LOCA analysis has been performed at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The major plant parameters assumed in the best-estimate LOCA analysis will be documented in the respective sections of the Seabrook Station UFSAR, as noted in LAR Table 6.1.1-1. These and other UFSAR changes resulting from approval of this LAR will be made in accordance with 10 CFR 50.71(e).

Both FPL Energy and its analysis vendor (Westinghouse) have ongoing processes which assure that the values and ranges of the Best Estimate Large Break LOCA analysis inputs for peak cladding temperature-sensitive parameters bound the values and ranges of the as-operated plant for those parameters.

6.1.1.2 TECHNICAL ANALYSIS

The best-estimate large break LOCA analysis has been performed for Seabrook Station using the methodology contained in WCAP-12945-P-A. The plant specific parameters used in the analysis are bounded by the models and correlations contained in the generic methodology. Therefore, the Seabrook Station analysis conforms to 10 CFR 50.46 and 10 CFR 50, Appendix K, Section II and meets the intent of Regulatory Guide 1.157. The conclusions of the analysis are that there is a high level of probability that:

1. The calculated maximum fuel element cladding temperature (peak cladding temperature) will not exceed 2200°F.
2. The calculated total oxidation of the cladding (maximum cladding oxidation) will not exceed 0.17 times the total cladding thickness before oxidation.
3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam (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.

4. The calculated changes in core geometry are such that the core remains amenable to cooling.
5. After successful initial operation of the Emergency Core Cooling Systems, 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.

LAR Table 6.1.1-2 presents the 95th percentile peak clad temperature, maximum cladding oxidation, maximum hydrogen generation, and cooling results for Seabrook Station.

Therefore, FPL Energy Seabrook has concluded that adopting the best-estimate large break LOCA methodology for Seabrook Station at the SPU conditions would not adversely affect the health and safety of the public.

6.1.2 SMALL BREAK LOSS OF COOLANT ACCIDENT (SBLOCA)

6.1.2.1 INTRODUCTION

This section summarizes the SBLOCA analysis performed to support the SPU for Seabrook Station at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The analysis was performed to demonstrate conformance with the 10 CFR 50.46 requirements for the conditions associated with the SPU.

A summary of the input assumptions and initial conditions is provided in LAR Section 6.1.2.2. This is followed by a description of the methodology employed and the analysis performed in LAR Section 6.1.2.3. The acceptance criteria is provided in LAR Section 6.1.2.4 and the results and conclusions discussion is presented in LAR Section 6.1.2.5.

6.1.2.2 INPUT ASSUMPTIONS AND INITIAL CONDITIONS

6.1.2.2.1 ASSUMPTIONS

The assumptions required by 10 CFR 50, Appendix K have been utilized in the Seabrook Station SBLOCA analysis. These include the peaking factors simultaneously at their most limiting values, Baker-Just zirc water reaction rate, 120% of 1971 American Nuclear Society 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 10 CFR 50, Appendix K SBLOCA Evaluation Model are:

1. Break area is < 1 ft^2
2. Hot full power (Mode 1 or 2)
3. All rod control cluster assemblies except the single most reactive rod insert following reactor trip

4. Loss of offsite power assumed at reactor trip time results in the following assumptions
   - Loss of one emergency diesel generator and subsequent loss of one train of the pumped Emergency Core Cooling System
   - Reactor coolant pump trip and coastdown
   - Main steam line isolation (no steam dump capability)
5. Standard 4 loop Emergency Core Cooling System spilling assumptions

A complete spectrum of break sizes, including diameters of 3, 4 and 6 inches, was analyzed.

6.1.2.2.2 INPUT PARAMETERS

Key input parameters are summarized in LAR Table 6.1.2-1.

6.1.2.2.3 DISCUSSION OF T_{avg} INPUT

The SBLOCA analysis is performed at the maximum steam generator tube plugging value of 10%. The specified T_{avg} range for Seabrook Station in this analysis is 571.0°F to 589.1°F. The analysis is performed at 589.1°F but is bounding for the range of 571.0°F to 589.1°F.

6.1.2.3 DESCRIPTION OF METHODOLOGY/ANALYSIS

6.1.2.3.1 DESCRIPTION OF SBLOCA ENGINEERING METHODOLOGY AND CODES

The SBLOCA analysis was performed with the Westinghouse Emergency Core Cooling System Evaluation Model using NOTRUMP [References 6.1-6, 6.1-7 and 6.1-8], including changes to the model and methodology as described in References 6.1-8 and 6.1-9. The NOTRUMP Evaluation Model includes the following computer codes:

NOTRUMP: Thermal-hydraulic response of the Reactor Coolant System during transient.

SBLOCTA: Fuel rod / cladding heat-up during the transient.

A brief summary of each of these codes is presented in the following sections:

NOTRUMP Code

The NOTRUMP computer code is a one-dimensional general thermal-hydraulic network code with a number of features. Among these features are the calculation of thermal non-equilibrium in the fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes and regime-dependent heat transfer correlations. Heat transfer in the core is calculated based on the LOCTA-IV code, which considers heat transfer regimes including single phase convection to subcooled liquid, nucleate boiling, transition boiling, film boiling and convection to superheated vapor in both laminar and turbulent flows. In addition, the NOTRUMP SBLOCA Emergency Core Cooling System Evaluation Model was developed to determine the Reactor Coolant System response to

design basis SBLOCAs and to address the Nuclear Regulatory Commission concerns expressed in NUREG-0611.

The NOTRUMP model is generally made up of nodes (control volumes) and links (mass and energy transport). This model determines the thermal-hydraulic response of the Reactor Coolant System during the SBLOCA transient based upon initial operating conditions, core nuclear design parameters, steam generator and reactor vessel characteristics as well as Emergency Core Cooling System performance and other plant specific parameters previously used for the Seabrook SBLOCA analysis. Select Reactor Coolant System response boundary conditions are extracted from the NOTRUMP calculations and are used in the SBLOCTA fuel rod heat-up code.

SBLOCTA Code

SBLOCTA is a small-break specific version of the LOCTA-IV code. Peak cladding temperature calculations are performed with the LOCTA-IV code using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow and mixture levels as boundary conditions. LOCTA-IV models the hot rod and the average hot assembly rod. As stated above, LOCTA-IV contains many heat transfer models, however, due to the relatively low velocities experienced in the core during the SBLOCA transient, heat transfer is basically limited to forced convection to super-heated vapor and rod-to-rod radiation. In addition to peak cladding temperature, SBLOCTA also calculates maximum local and hot-rod axial average ZrO_2 reaction.

6.1.2.3.2 DESCRIPTION OF ANALYSIS PERFORMED FOR SBLOCA

The methodology employed consists of first calculating 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 peak clad temperature, cladding oxidation, and hydrogen generation are below their limiting values as defined by 10 CFR 50.46 [Reference 6.1-3].

The analysis consists of a break spectrum using the approved methodology as documented in References 6.1-7 and 6.1-9. For the Seabrook Station SBLOCA analysis, a complete break spectrum (3, 4, and 6 inch diameter) has been analyzed to confirm that the 4 inch diameter break remains limiting. Additionally, annular blankets were modelled for the limiting case. The results are presented in LAR Tables 6.1.2.5-2 and 6.1.2.5-3.

Fuel temperatures and pressures for the 17x17 robust fuel assemblies were used in the analysis. Although there is little difference between modeling integral fuel burnable absorber vs. non-integral fuel burnable absorber fuel for SBLOCA, non-integral fuel burnable absorber results in more limiting results. Only non-integral fuel burnable absorber fuel is modelled in the SBLOCA analysis since non-integral fuel burnable absorber fuel yields more limiting results. Therefore, only non-integral fuel burnable absorber fuel is analyzed for SBLOCA. Other features that were explicitly analyzed are described in LAR Table 6.1.2.5-1.

6.1.2.4 DESIGN BASIS ACCEPTANCE CRITERIA

The criteria for acceptability for the Loss of Coolant Accidents are found in 10 CFR 50.46(b) [Reference 6.1-3] and are quoted below:

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

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

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.

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

Long-term cooling. After any calculated successful initial operation of the Emergency Core Cooling System, 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.

6.1.2.5 RESULTS AND CONCLUSIONS

6.1.2.5.1 DESCRIPTION OF LIMITING 4 INCH DIAMETER BREAK CASE

The analysis determined that the limiting break size for the SBLOCA is a 4-inch break, as is the case for the current analysis. For the limiting 4 inch diameter break, the primary side pressure begins a rapid drop at the time of break initiation (LAR Figure 6.1.2.5-1). A reactor trip signal is generated at 9.9 seconds followed by a safety injection signal at 20 seconds. This primary side depressurization is checked when the primary side pressure comes into balance with the secondary side pressure, which acts as the predominant energy release path during this portion of the transient. This balance is upset when the broken loop, loop seal clears at approximately 259 seconds creating a vapor vent path between the top of the core and the break in the cold leg.

At break initiation, the core mixture level (LAR Figure 6.1.2.5-2) 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 depresses below the bottom of the hot legs, the rate of uncovery once again establishes itself until loop seal clearing occurs. After loop seal clearing, the core and downcomer are allowed to come into a manometric balance as the downcomer level falls in response to the draining of the adjacent cold legs.

The core level continues to decrease until the top of the core uncovers at 523 seconds leading to the start of clad heat up. As illustrated in LAR Figure 6.1.2.5-4, the safety injection flow rate continues to increase as the Reactor Coolant System pressure

decreases. The safety injection replenishes the core level, which results in a reversal in the clad heat up transient. The Peak Clad Temperature of 1373°F occurs at 884.2 seconds (LAR Figure 6.1.2.5-5) followed by a steady increase in the core mixture level (LAR Figure 6.1.2.5-2). The accumulators inject at 806 seconds.

The transient core exit steam flow has been presented in LAR Figure 6.1.2.5-3. The results of the 4 inch diameter break case are presented in LAR Tables 6.1.2.5-2 and 6.1.2.5-3. The figures provided for the 4-inch limiting case are:

- LAR Figure 6.1.2.5-1 – Pressurizer Pressure
- LAR Figure 6.1.2.5-2 – Core Mixture Level
- LAR Figure 6.1.2.5-3 – Core Exit Steam Flow
- LAR Figure 6.1.2.5-4 – Broken Loop and Intact Loop Pumped Safety Injection Flow Rate
- LAR Figure 6.1.2.5-5 – Peak Clad Temperature at Peak Clad Temperature Elevation (11.25 ft)

6.1.2.5.2 NON-LIMITING RESULTS

The results of the 3 and 6 inch diameter break cases have been presented in LAR Tables 6.1.2.5-2 and 6.1.2.5-3. LAR Figures 6.1.2.5-6 through 6.1.2.5-11 pertain to the 3 and 6 inch diameter break cases. The figures provided for the non-limiting cases are:

- LAR Figure 6.1.2.5-6 – 3-Inch Break, Pressurizer Pressure
- LAR Figure 6.1.2.5-7 – 3-Inch Break, Core Mixture Level
- LAR Figure 6.1.2.5-8 – 3- Inch Break, Peak Clad Temperature at Peak Clad Temperature Elevation (11.25 ft)
- LAR Figure 6.1.2.5-9 – 6-Inch Break, Pressurizer Pressure
- LAR Figure 6.1.2.5-10 – 6-Inch Break, Core Mixture Level
- LAR Figure 6.1.2.5-11 – 6-Inch Break, Peak Clad Temperature at Peak Clad Temperature Elevation (11.0 ft)

6.1.2.5.3 FUEL FEATURES EVALUATION

The fuel features identified in LAR Table 6.1.2.5-1 have been accounted for in the SBLOCA analysis. As noted in LAR Table 6.1.2.5-1, 6 inch annular blankets have been included in this analysis. The 6 inch blankets have been explicitly modeled in the rod heat up calculations for the limiting 4 inch diameter break case. The rod heatup results with the 6 inch blankets were identical to the results without annular blankets.

6.1.2.5.4 RACK-UP ITEM INCORPORATION

The SBLOCA analysis for the SPU becomes the new SBLOCA analysis of record. As a result of this analysis, all rack-up items from the Seabrook Station 10 CFR 50.46 Peak Clad Temperature Report have been incorporated. Analysis used the latest version of the NOTRUMP EM codes and incorporated all other items into the analysis.

6.1.2.5.5 MAXIMUM LOCAL AND CORE-WIDE OXIDATION

All cases meet the 10 CFR 50.46 requirements of maximum local and core-wide oxidation. The local oxidation of the cladding does not exceed 17% and the calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam does not exceed 1%.

6.1.2.5.6 CONCLUSIONS

The results of the analysis show that the acceptance criteria discussed in LAR Section 6.1.2.4 for the SBLOCA have been met. The limiting peak cladding temperature for Seabrook Station will be reported as 1373°F, which occurs for the 4 inch diameter break case. Local oxidation of the cladding is less than 17%, and the core-wide oxidation is less than 1.0%. The 4 inch diameter limiting break case is shown in LAR Figures 6.1.2.5-1 through 6.1.2.5-5.

6.1.3 POST-LOCA SUBCRITICALITY AND LONG TERM CORE COOLING

6.1.3.1 INTRODUCTION AND BACKGROUND

As part of the SPU, proposed Technical Specification 3.5.4, minimum refueling water storage tank boron concentration is being reduced from 2700 ppm to 2400 ppm. Similarly, Technical Specification 3.5.1, minimum accumulator boron concentration is being reduced from 2600 ppm to 2300 ppm. To support this change and the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), the post-LOCA subcriticality calculations were performed.

The post-LOCA subcriticality calculations demonstrate that the core will remain subcritical upon entering the Emergency Core Cooling System sump recirculation phase. 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. Long-term core cooling also requires adequate Emergency Core Cooling System flow to provide core cooling during the cold leg recirculation period.

6.1.3.2 INPUT PARAMETERS AND ASSUMPTIONS

The sump mixed mean boron concentration calculational 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; i.e., 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 Reactor Coolant System conditions.

The post-LOCA subcriticality calculations for SPU conditions conservatively assume a refueling water storage tank volume that does not credit the additional refueling water storage tank volume drained by the Containment Spray System. The Westinghouse position is that the core will remain subcritical post-LOCA by borated water from various injected Emergency Core Cooling System water sources.

Long-term core cooling also requires adequate Emergency Core Cooling System flow to provide core cooling. For Seabrook Station, the confirmation of adequate Emergency Core Cooling System flow during the cold leg recirculation period is based on the following assumptions.

- The current SBLOCA analysis methodology explicitly models Emergency Core Cooling System flow enthalpy changes during the switchover from cold leg injection to cold leg recirculation.
- The Long-term core cooling methodology assumes that LBLOCA Emergency Core Cooling System flows are not adversely affected by the switchover from cold leg injection to cold leg recirculation.

6.1.3.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The post-LOCA mixed mean sump boron concentration as a function of pre-trip Reactor Coolant System boron concentration was developed for the SPU. The curve is included in the Reload Safety Analysis Checklist and is checked for each reload cycle to ensure that adequate boron will exist in the sump to maintain subcriticality in the long-term post-LOCA.

In addition to confirming the post-LOCA subcriticality, maintenance of long-term core cooling after switchover to sump recirculation mode must be demonstrated. For LBLOCA, core cooling is ensured by confirming that there is sufficient Emergency Core Cooling System flow to offset core boil-off and boiling in the downcomer and lower plenum. For SBLOCA, potential effects of Emergency Core Cooling System flow interruptions and/or enthalpy changes at switchover to the recirculation mode are considered as part of the SBLOCA analysis. Consistent with the other LOCA analyses, the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) was assumed.

6.1.3.4 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 Reactor Coolant System peak xenon boron concentration, is included in the Reload Safety Analysis Checklist and is verified for each reload cycle to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA. The subcriticality check performed for the Reload Safety Analysis Checklist (not including credit for control rods or xenon) adequately addresses potential recriticality due to sump dilution upon entering hot leg recirculation.

With respect to long-term core cooling, the SBLOCA analysis discussed in LAR Subsection 6.1.2 modeled the Emergency Core Cooling System flow enthalpy change

during the switchover from cold leg injection to cold leg recirculation. Furthermore, as stated above, the long term core cooling methodology assumes that LBLOCA Emergency Core Cooling System flows are not adversely affected by the switchover to cold leg recirculation.

6.1.3.5 CONCLUSIONS

A post-LOCA subcriticality boron limit curve was developed for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Provided that the maximum critical boron concentration remains below the post-LOCA sump boron concentration limit curve (for all rods out, no Xenon, 68°F – 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. Emergency Core Cooling System flow during the cold leg recirculation period is adequate to provide long-term core cooling.

6.1.4 CONTAINMENT SUMP pH CONTROL

6.1.4.1 DESCRIPTION

The containment sump pH control during a LOCA is described in the Seabrook Station UFSAR Section 6.5.2. The SPU evaluation demonstrated that the spray and sump solution pH values remain within the specified limits. During a design basis LOCA, the Containment Spray System limits offsite fission product release and dose consequences by removing iodine concentrations in the containment atmosphere. Removal of fission products, specifically iodine, is enhanced by maintaining the spray and sump solution pH within the limits of 8.5 to 10.5. In addition, spray and sump pH must be controlled post-design basis accident to limit corrosion of piping and equipment that must be relied upon to mitigate the accident consequences.

6.1.4.2 EVALUATION

The containment pH control was evaluated to ensure it is capable of performing the intended functions at SPU conditions. The inputs used to determine the containment spray and sump pH are not impacted by the SPU. However, as indicated in the proposed changes to Technical Specifications 3/4.5.1 and 3/4.5.4, the boron concentration ranges for the accumulators and the refueling water storage tank are changing.

The containment spray and sump pH values were evaluated using these revised boron concentration ranges. The evaluation determined that the minimum range of containment spray and sump pH is within the limits of 8.5 to 10.5 following the SPU. Therefore, Seabrook Station containment pH control meets the acceptance criteria given by Standard Review Plan, NUREG 0800 Section 6.5.2 [Reference 6.1-11]. This is consistent with the Alternate Source Term methodology.

6.1.4.3 CONCLUSION

The minimum and maximum containment spray and sump pH are within the Standard Review Plan limits of 8.5 to 10.5 to ensure proper iodine removal from the containment

atmosphere and corrosion control in the event of an accident. This also is consistent with the Alternate Source Term methodology.

6.1.5 HOT LEG SWITCHOVER

6.1.5.1 INTRODUCTION AND BACKGROUND

As part of the SPU, the Technical Specification maximum refueling water storage tank and accumulator boron concentrations are being reduced from 2900 ppm to 2600 ppm for the SPU (Technical Specifications 3.5.4 and 3.5.1, respectively). To support this change at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), the hot leg switchover time is recalculated.

A post-LOCA hot leg switchover time is calculated to support emergency operating procedures that require a realignment of the recirculation safety injection flowpath from the cold legs to the hot legs. This realignment to the hot legs precludes boron precipitation in the reactor vessel following a LBLOCA. At issue are cold leg breaks where injected Safety Injection 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 Emergency Core Cooling System evaluation model relies on the preclusion of boron precipitation as one criteria for assuring core coolable geometry.

6.1.5.2 INPUT PARAMETERS AND ASSUMPTIONS

The hot leg switchover calculation model is based on the following assumptions:

- A boric acid concentration level is computed over time for a core-region mixing volume.
- The boric acid concentration limit is the experimentally determined boric acid saturation concentration with a four weight-percent uncertainty factor.
- The decay heat generation rate is based on the 1971 American Nuclear Society Standard for an infinite operating time with 20% uncertainty.
- The boron concentration of the make-up Safety Injection 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, boron precipitation is precluded and core cooling is assured by established minimum recirculation flow criteria for the hot legs, cold legs, or simultaneous hot and cold leg recirculation.

The methodology described above is consistent with, or otherwise conservative with respect to, the methodology described in Reference 6.1-10.

The following component masses and boron concentrations are assumed in the hot leg switchover calculations:

Component	Mass (lbm)	Boron Concentration (ppm)
Accumulator	219,733	2600
Reactor Coolant System	498,269	2400
Refueling Water Storage Tank	3,571,107	2600

The assumptions made by this analysis are consistent with the current licensing basis, with the exception of the power level, boron concentrations and conservative application of the 10 CFR 50.46 Appendix K Decay Heat Model.

6.1.5.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The major inputs to the hot leg switchover time calculation include the core power assumptions and boron concentrations and water volume/masses for significant contributors to the containment sump. The increase in core power for the uprate affects decay heat and thus requires recalculation of the hot leg switchover time and hot leg recirculation minimum required flows. The decrease in refueling water storage tank and accumulator boron concentrations also requires recalculations of the hot leg switchover time.

For the SPU, a new hot leg switchover time was calculated using the input parameters and assumptions described in the previous section. All inputs to the calculation were reviewed and confirmed to be appropriate for plant operation at the SPU conditions. The SPU calculations were based on analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), 10 CFR 50, Appendix K decay heat and reduced accumulator and refueling water storage tank boron concentrations.

A revised set of hot leg recirculation minimum required flows and a new hot leg switchover time were calculated at the SPU conditions.

6.1.5.4 ACCEPTANCE CRITERIA AND RESULTS

There are no specific acceptance criteria on the new hot leg switchover time for SPU conditions so long as the Seabrook Station UFSAR and Emergency Operating Procedures are revised appropriately. The available flows at hot leg switchover time are acceptable if they meet or exceed the calculated minimum flow requirements or are otherwise shown to be sufficient to provide core cooling.

At the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), a new hot leg switchover time of 7.46 hours was calculated. The time of 7.46 hours was rounded down to 7.0 hours for additional conservatism. The available flows at the hot leg switchover time of 7.0 hours were shown to be sufficient to provide core cooling. To address NSAL-04-01 [Reference 6.1-13], the minimum hot leg recirculation flows were also shown to be sufficient to provide core cooling for the hot leg recirculation alignment beginning after 5.5 hours.

6.1.5.5 CONCLUSIONS

A hot leg switchover time of 7.0 hours will preclude boron precipitation for post-LOCA scenarios for the SPU conditions. The available Emergency Core Cooling System flows at hot leg switchover were shown to be sufficient to provide core cooling.

6.1.6 POST-LOCA HYDROGEN GENERATION

6.1.6.1 DESCRIPTION

The Combustible Gas Control System is described in the Seabrook Station UFSAR Section 6.2.5. The evaluation demonstrates that the Combustible Gas Control system remains bounded for operation at SPU conditions. Following a postulated LOCA, hydrogen may be generated inside the containment by various reactions including; zirconium fuel clad water reaction, corrosion of aluminum and zinc and radiolysis of core and sump water. The Combustible Gas Control System provides mechanisms to mix the containment atmosphere to eliminate localized hydrogen buildup, monitor hydrogen concentration, and reduce the combustible gas concentrations within the containment.

The hydrogen monitor sub-system is a two train redundant safety class 1E system. The analyzers are located outside of containment. To maintain the separation requirements of a safety class 1E redundant system, each train is powered from separate safety related buses.

The hydrogen recombiners provide the primary means of post-LOCA containment hydrogen removal. Two hydrogen recombiners are located at the perimeter of the operating floor inside containment. The recombiners are fully redundant, separate systems so that no single failure can effect the operation of both recombiners. Each recombiner consists of an inlet preheater section, a heater/recombiner section, and a discharge mixing chamber. The heater section consists of four vertically stacked assemblies of electric heaters, each assembly containing individual heating elements. An outer enclosure provides protection against containment spray water.

The purge system provides the backup means for removing hydrogen from the containment. The system consists of a flow meter, throttle valve and associated piping. The purge exhausts through the emergency filters located in the containment enclosure to the plant vent. Components and ductwork associated with the filters are classified as Safety Class 3 and seismic Category I. The piping inside the containment and the containment penetration connections associated with the purge system are duplicated to provide independent and redundant capability and to prevent a single failure from stopping the containment purge/flow vent. External to the containment, a single line runs from the penetration area to the containment enclosure emergency filters.

6.1.6.2 EVALUATION

The Combustible Gas Control System was evaluated at SPU conditions to ensure that it is capable of performing its post-LOCA function of preventing containment hydrogen concentration from exceeding the 4% volume limit.

Using the model presented in Regulatory Guide 1.7, it was found that if only one recombiner is turned on after a LOCA when the hydrogen concentration reaches 3.5 volume percent, the hydrogen concentration begins to drop immediately. Although actuation of the recombiners could be delayed, a 3.5 volume percent hydrogen concentration start point is selected to provide margin for detection of failure of both recombiners. In this event, the backup purge system would be started when the hydrogen concentration reaches 3.8 volume percent. The containment hydrogen concentration without the recombiner and with purging at a rate of 3.0% of the containment volume per day, results in a maximum hydrogen concentration of approximately 3.81 volume percent.

6.1.6.3 CONCLUSION

The resultant post-LOCA hydrogen concentrations associated with operating the plant at SPU will still be less than the 4.0 volume percent limit.

6.1.7 LOSS OF COOLANT ACCIDENT HYDRAULIC FORCES

6.1.7.1 INTRODUCTION AND BACKGROUND

The LOCA hydraulic forces analysis generates the hydraulic forcing functions that occur on Reactor Coolant System components as a result of a postulated LOCA. The LOCA hydraulic forces are generated for conditions consistent with minimum thermal design flow and maximum Reactor Coolant System power. The most recent qualification of the Seabrook Station vessel internals and fuel was performed using an advanced beam model version of MULTIFLEX, in accordance with methodology approved by the Nuclear Regulatory Commission [Reference 6.1-4]. This same version of the MULTIFLEX code was used for the Seabrook Station SPU LOCA hydraulic forces analysis.

6.1.7.2 INPUT PARAMETERS AND ASSUMPTIONS

The following operating conditions were considered in establishing the limiting temperatures and pressures for the Seabrook Station LOCA hydraulic forces analyses:

- Initial Reactor Coolant System conditions associated with a minimum thermal design flow of 93,600 gpm per loop (assumes 10% steam generator tube plugging)
- Analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level)
- A nominal Reactor Coolant System hot full power T_{avg} range of 571.0°F to 589.1°F
- An Reactor Coolant System temperature uncertainty of ±6°F
- A feedwater temperature range of 390.0°F to 452.4°F
- A nominal Reactor Coolant System pressure of 2250 psia
- A pressurizer pressure uncertainty of ±50 psi

General Design Criteria 4 allows main coolant piping breaks to be "excluded from the design basis when analyses reviewed and approved by the Nuclear Regulatory Commission demonstrate that the probability of fluid system piping rupture is extremely

low under conditions consistent with the design basis for the piping." This exemption is generally referred to as leak-before-break. Leak-before-break licensing allows Reactor Coolant System components to be evaluated for LOCA integrity considering the next most limiting auxiliary line breaks that, for Seabrook Station, are the accumulator line, the pressurizer surge line, and the residual heat removal lines. The only exception to the use of auxiliary line breaks for the Seabrook Station structural qualification is the modeling of a limited displacement double-ended guillotine reactor vessel outlet nozzle break to demonstrate control rod insertion following a LOCA.

6.1.7.3 DESCRIPTION OF EVALUATION

LOCA forces are generated with a focus on the component of interest; loop, vessel, steam generator, or rod control cluster assembly guide tubes using the advanced beam model version of MULTIFLEX, assuming a conservative 1 msec break opening time. Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel.

For the reactor pressure vessel and specific vessel internal components, the MULTIFLEX code generates the LOCA thermal-hydraulic transient data that is input to the LATFORC and FORCE2 post-processing codes. These codes, in turn, are used to calculate the actual forces on the various components. These forcing functions for the horizontal and vertical LOCA hydraulic forces, combined with seismic, thermal, and system shaking loads, are used in the structural evaluations to determine the resultant mechanical loads on the vessel and vessel internals.

The loop forces analysis uses the THRUST post-processing code to generate the X, Y and Z directional loop component forces during a LOCA blowdown using the Reactor Coolant System pressure, density, and mass flux calculated by the MULTIFLEX code. The hydraulic transient time history data is extracted directly from the MULTIFLEX output for steam generator and some reactor vessel internal components such as baffle bolts or rod control cluster assembly guide tubes.

6.1.7.4 ACCEPTANCE CRITERIA

LOCA hydraulic forces are provided as input to structural qualification analyses, and as such have no independent regulatory acceptance criteria. The structural analyses performed using these forcing functions are done to demonstrate compliance with 10 CFR 50, Appendix A, General Design Criteria 4.

6.1.7.5 RESULTS

For the Seabrook Station SPU, relevant LOCA hydraulic forces analyses were performed at the SPU operating conditions using models specific to the Seabrook Station NSSS design. These analyses included reactor vessel internals and fuel, loop piping, steam generator, and rod control cluster assembly guide tube forces. The results of these analyses were used as input to the structural analyses for component qualification.

6.1.7.6 CONCLUSIONS

LOCA hydraulic forces were generated for the Seabrook Station SPU parameters specified in LAR Section 2.0. Since the vessel, loop, steam generator, and control rod insertability analyses (LAR Subsections 5.1.1, 5.5, 5.7.1, and 5.2.5 respectively) demonstrate acceptable results, the forces for SPU conditions are acceptable.

Table 6.1.1-1
Major Plant Parameter Assumptions used in the Best-Estimate Large Break LOCA Analysis

Parameter	Documentation
Plant Physical Description	
Steam Generator Tube Plugging	UFSAR Section 15.6.5
Plant Initial Operating	
Reactor Power	UFSAR Section 15.6.5
Peaking Factors	UFSAR Section 15.6.5
Axial Power Distribution	UFSAR Section 15.6.5
Fluid Conditions	
T_{avg}	UFSAR Section 15.6.5
Pressurizer Pressure	UFSAR Section 15.6.5
Reactor Coolant Flow	UFSAR Section 15.6.5
Accumulator Temperature	UFSAR Section 15.6.5
Accumulator Pressure	UFSAR Section 15.6.5
Accumulator Volume	UFSAR Section 15.6.5
Accident Boundary Conditions	
Single Failure Assumptions	UFSAR Section 15.6.5
Safety Injection Flow	UFSAR Section 15.6.5
Safety Injection Temperature	UFSAR Section 15.6.5
Diesel generator Delay Time	UFSAR Section 15.6.5
Containment Pressure	UFSAR Section 15.6.5

TABLE 6.1.1-2
SEABROOK STATION
BEST-ESTIMATE LARGE BREAK LOCA RESULTS

	ANALYSIS VALUE	ACCEPTANCE CRITERIA
95th Percentile Peak Clad Temperature (°F)(1)	1784	< 2200
Maximum Cladding Oxidation (%)(1)	3.53	< 17
Maximum Hydrogen Generation (%)(1)	0.3	< 1
Coolable Geometry	Core Remains Coolable	Core Remains Coolable
Long Term Cooling	Core Remains Cool in Long Term	Core Remains Cool in Long Term

NOTES:

1. Calculated using the methodology in Reference 6.1-1.

TABLE 6.1.2-1
INPUT PARAMETERS AND ASSUMPTIONS

A. Core Parameters	
Analyzed Core Power	3659 MWt
Fuel Type	17x17 robust fuel assemblies
Total Core Peaking Factor, F_Q	2.50
Hot Channel Enthalpy Rise Peaking Factor, $F_{\Delta H}$	1.65
Hot Assembly Average Power Factor, $\bar{P}_{HA}$	1.469
Axial Offset	+ 20%
K(z) limit	2 line segment
B. Reactor Coolant System	
Thermal design flow	93,600 gpm/loop
Total Core Bypass Flow	8.3%
Nominal vessel average temperature range	571.0 – 589.1°F
Vessel Average Temperature Uncertainty	+3.0 / -6.0 °F (1)
Pressurizer pressure	2250 psia
Pressurizer pressure uncertainty	+50 psi
Reactor coolant pump type	Model 93A1 7000HP
Reactor coolant pump effective weir height	0.4167 ft
C. Reactor Protection System	
Reactor Trip Setpoint	1935 psia
Reactor Trip Signal Processing Time (includes Rod Drop Time)	4.4 seconds
D. Auxiliary Feedwater System	
Maximum Auxiliary Feedwater temperature	100 °F
Minimum Auxiliary Feedwater flow rate	162.5 gpm/SG
Initiation Signal	LPP/SI
Auxiliary Feedwater delivery delay time	77 seconds
Purge Volume	150 ft^3/loop
E. Steam Generators	
Steam generator tube plugging	10 %
Main Feedwater isolation signal	LPP/Safety Injection
Main Feedwater isolation delay time	1.0 seconds
Main Feedwater flow coastdown time	10.0 seconds
Feedwater temperature	452.4 – 390.0°F
Steam generator to main steam safety valve ΔP	<100 psi
Steam generator safety valve flows (per steam generator)	Table 6.1.2.2-1

NOTES:

1. Represents a ± 3°F uncertainty plus a -3°F bias

TABLE 6.1.2-1 (continued)
INPUT PARAMETERS AND ASSUMPTIONS

F. Safety Injection	
Limiting single failure	One Engineered Safety Feature Emergency Bus
Safety Injection water temperature	98°F
Low-low pressurizer pressure signal	1650 psia
Safety Injection delay time	30 seconds
Safety Injection Flows vs. Pressure	Table 6.1.2.2-2
G. Accumulators	
Maximum initial temperature	120 °F
Initial water volume	850 ft^3
Minimum cover gas pressure	600 psia
H. Refueling Water Storage Tank Draindown Input	
Maximum Containment Spray Flow	7000 gpm
Minimum Usable Refueling Water Storage Tank Volume	350,000 gal
Maximum Delay Time for Switchover to Cold Leg Recirculation	No delay time
Safety Injection Flow Rate versus Pressure During Switchover to Cold Leg Recirculation	No change in flows
Safety Injection Flow Rate versus Pressure After Switchover to Cold Leg Recirculation	No change in flows
Maximum Safety Injection Water Temperature After Switchover to Cold Leg Recirculation Signal is Generated	212°F

TABLE 6.1.2.2-1
STEAM GENERATOR SAFETY VALVE FLOWS PER STEAM GENERATOR

Main Steam Safety Valves	Set Pressure (psig)	Uncertainty (%)	Accummulation (%)	Rated Flow at Full Open Pressure (lbm/hr)
1	1185	3	3	893,160
2	1195	3	3	900,607
3	1205	3	3	908,055
4	1215	3	3	915,502
5	1225	3	3	922,950

TABLE 6.1.2.2-2
SAFETY INJECTION FLOWS VS. PRESSURE
(MINIMUM SAFEGUARDS)

Reactor Coolant System Pressure (psig)	Intact Loop Flow (lbm/s)	Broken Loop Flow (lbm/s)
200	91.43	30.60
300	88.37	29.58
400	85.20	28.50
500	81.73	27.32
600	77.93	26.03
700	73.99	24.74
800	69.91	23.40
900	65.66	21.99
1000	60.81	20.33
1100	55.47	18.54
1200	49.14	16.41
1300	40.02	13.40
1360	27.10	9.06
1400	26.60	8.89
1500	25.27	8.45
1600	23.94	8.00
1800	21.07	7.04

TABLE 6.1.2.5-1
FUEL FEATURES INCORPORATION

Fuel Feature	How addressed in Analysis
17x17 array	Used explicitly in analysis.
Robust fuel assemblies	Used explicitly in analysis.
ZIRLO fuel rod cladding and grid material	Used explicitly in analysis.
6" annular blanket pellets	Although integral fuel burnable absorber fuel is not explicitly analyzed for SBLOCA, the geometry of the blankets has been modeled in the analysis while utilizing non-integral fuel burnable absorber PAD data.
Integral fuel burnable absorber	Integral fuel burnable absorber fuel is not explicitly modeled in SBLOCA analysis.

TABLE 6.1.2.5-2
NOTRUMP TRANSIENT RESULTS

	Event Time (sec)		
	3 Inch	4 Inch	6 Inch
Break Initiation	0.0	0.0	0.0
Reactor Trip Signal	17	9.9	5.5
S-Signal	30	20	14
Safety Injection Begins	60	50	44
Loop Seal Clearing	468	259	76
Core Uncovery	669	523	222
Accumulator Injection Begins	-	806	363
Refueling Water Storage Tank low-low level reached	2761	-	-
Core Recovery	2361	1507	457

TABLE 6.1.2.5-3
BEGINNING OF LIFE ROD HEATUP RESULTS

Parameter	3 Inch	4 Inch	6 Inch
Peak Clad Temperature (°F)	1113.8	1373.0	1155.4
Peak Clad Temperature Time (s)	1319.1	884.2	416.1
Peak Clad Temperature Elevation (ft)	11.25	11.25	11.00
HR Burst Time (s)	N/A	N/A	N/A
HR Burst Elevation (ft)	N/A	N/A	N/A
Max. Local ZrO_2 (%)	0.06	0.20	0.02
Max. Local ZrO_2 Elev (ft)	11.25	11.25	11.00
Hot Rod Axial Avg. ZrO_2 (%)	0.01	0.03	0.00

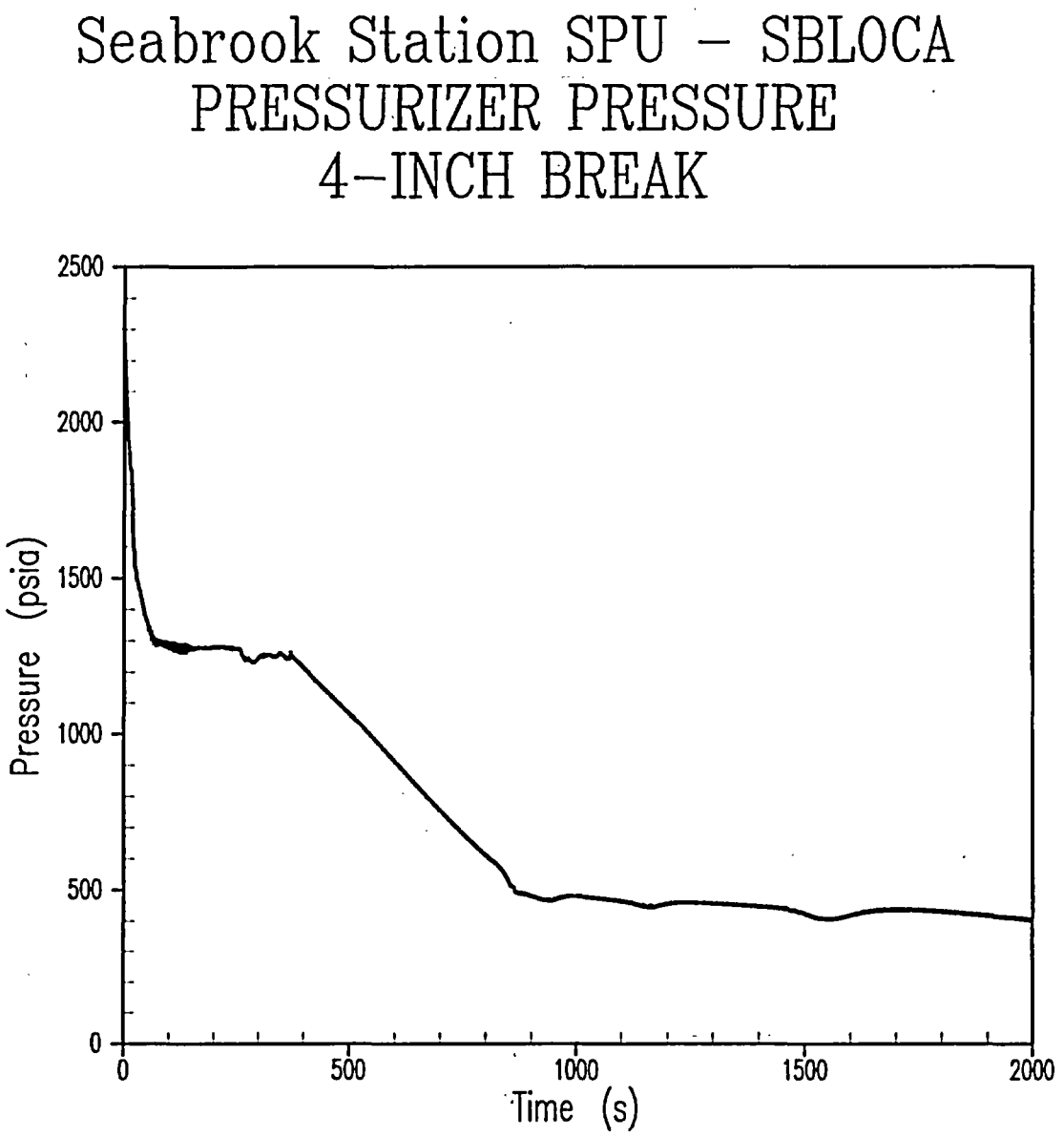


Figure 6.1.2.5-1
4-Inch Break Case, Pressurizer Pressure

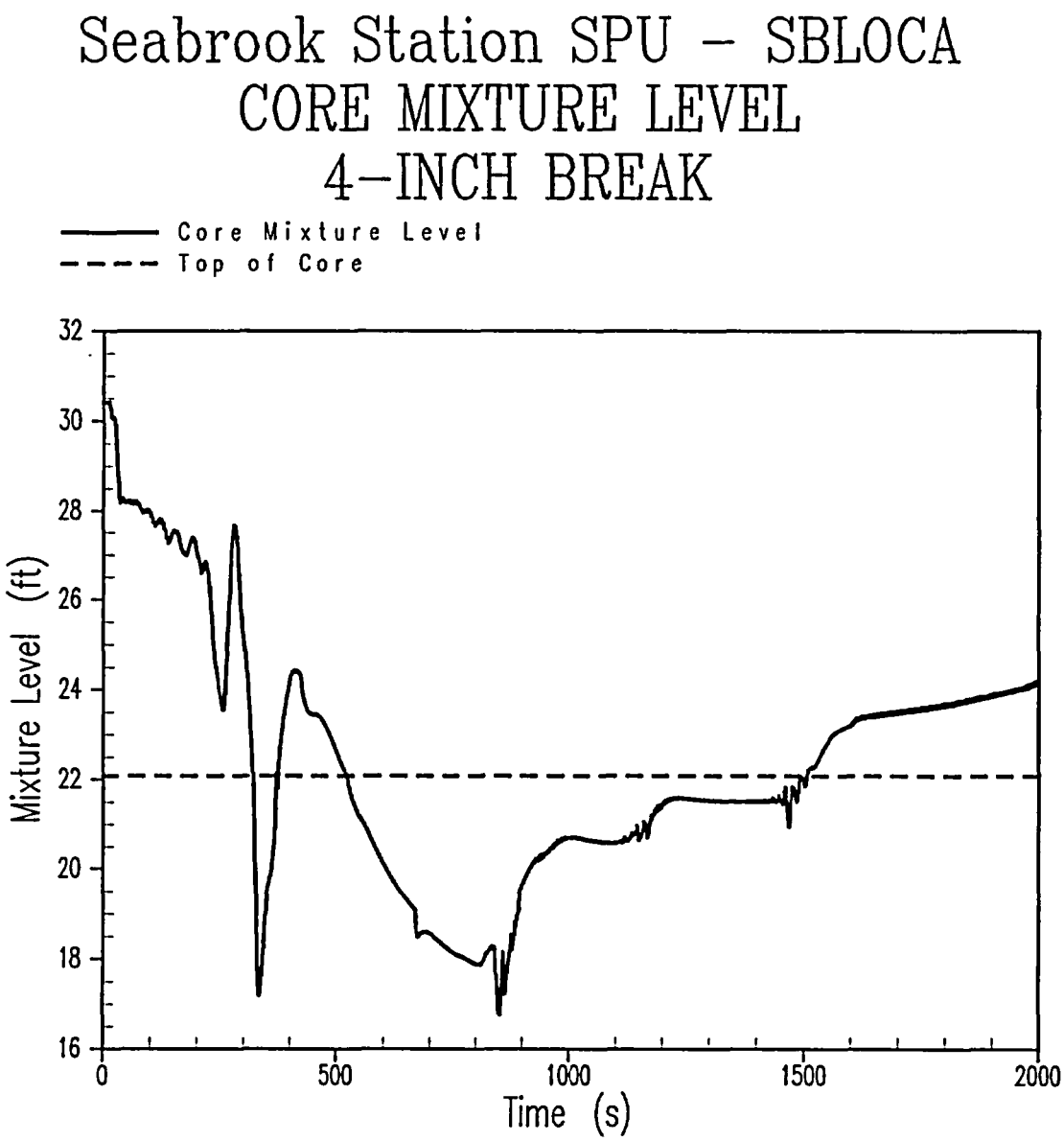


Figure 6.1.2.5-2
4-Inch Break Case, Core Mixture Level

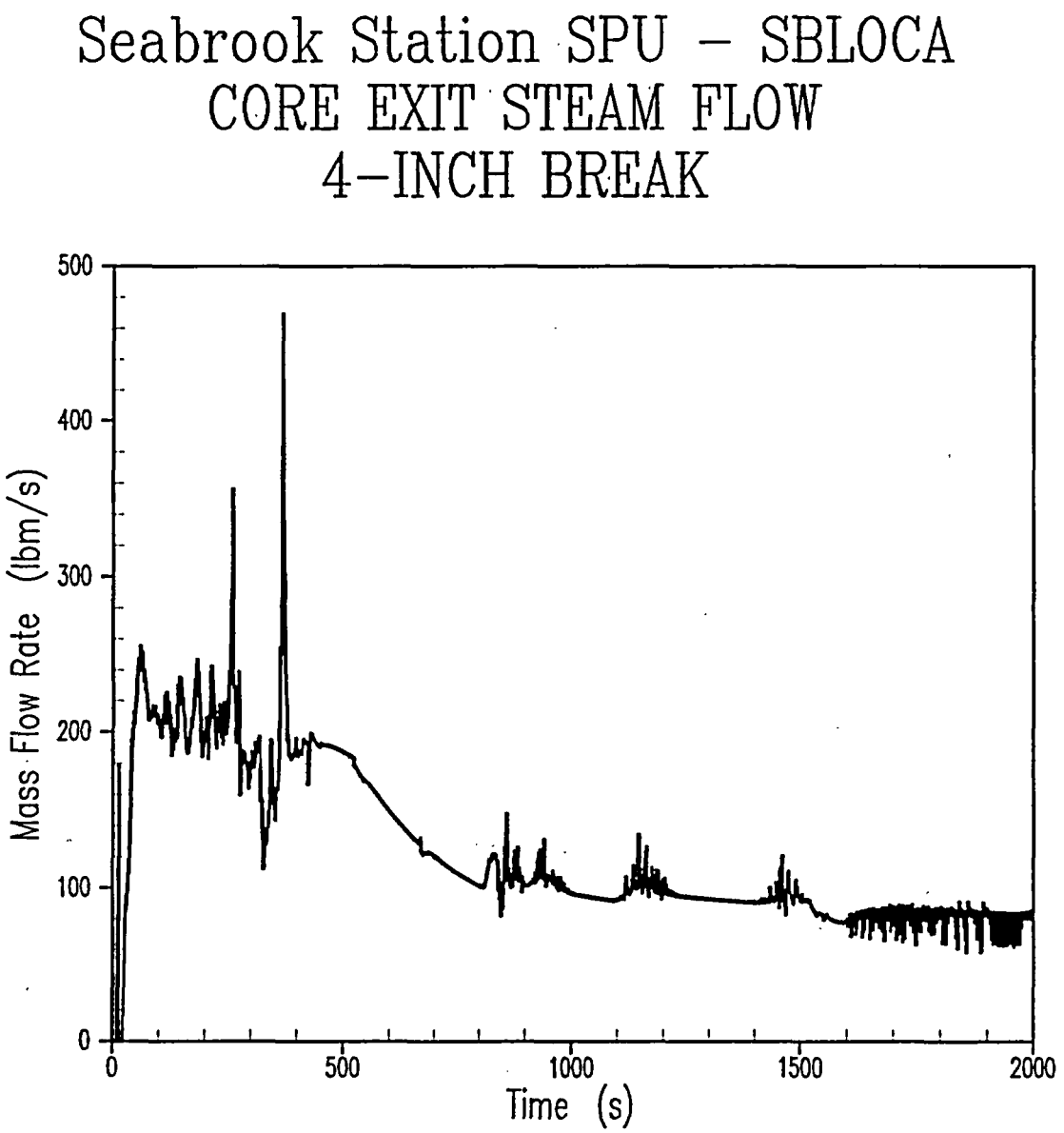


Figure 6.1.2.5-3
4-Inch Break Case, Core Exit Steam Flow

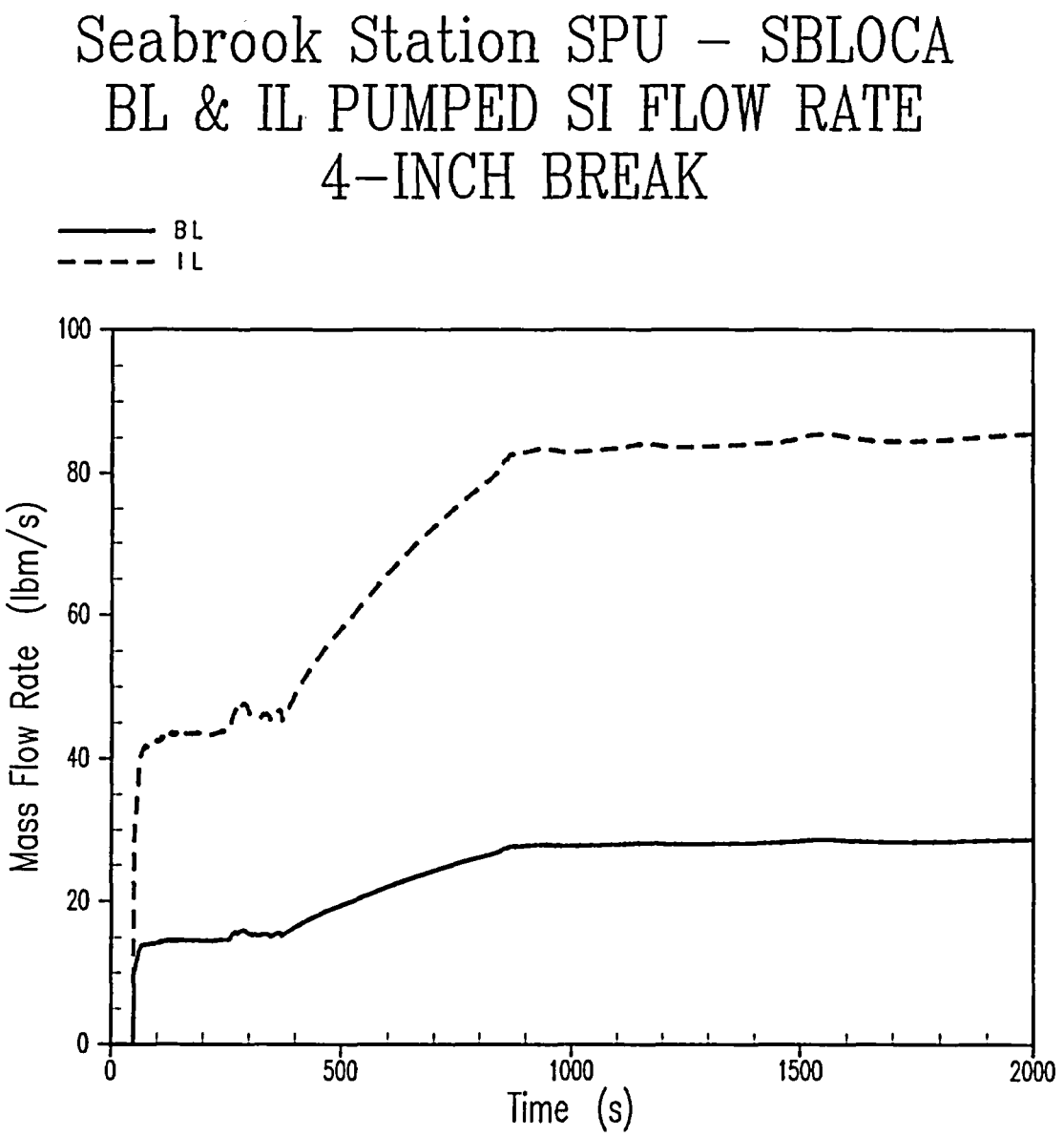


Figure 6.1.2.5-4
4-Inch Break Case, Broken Loop (BL) and Intact Loop (IL)
Pumped Safety Injection Flow Rate

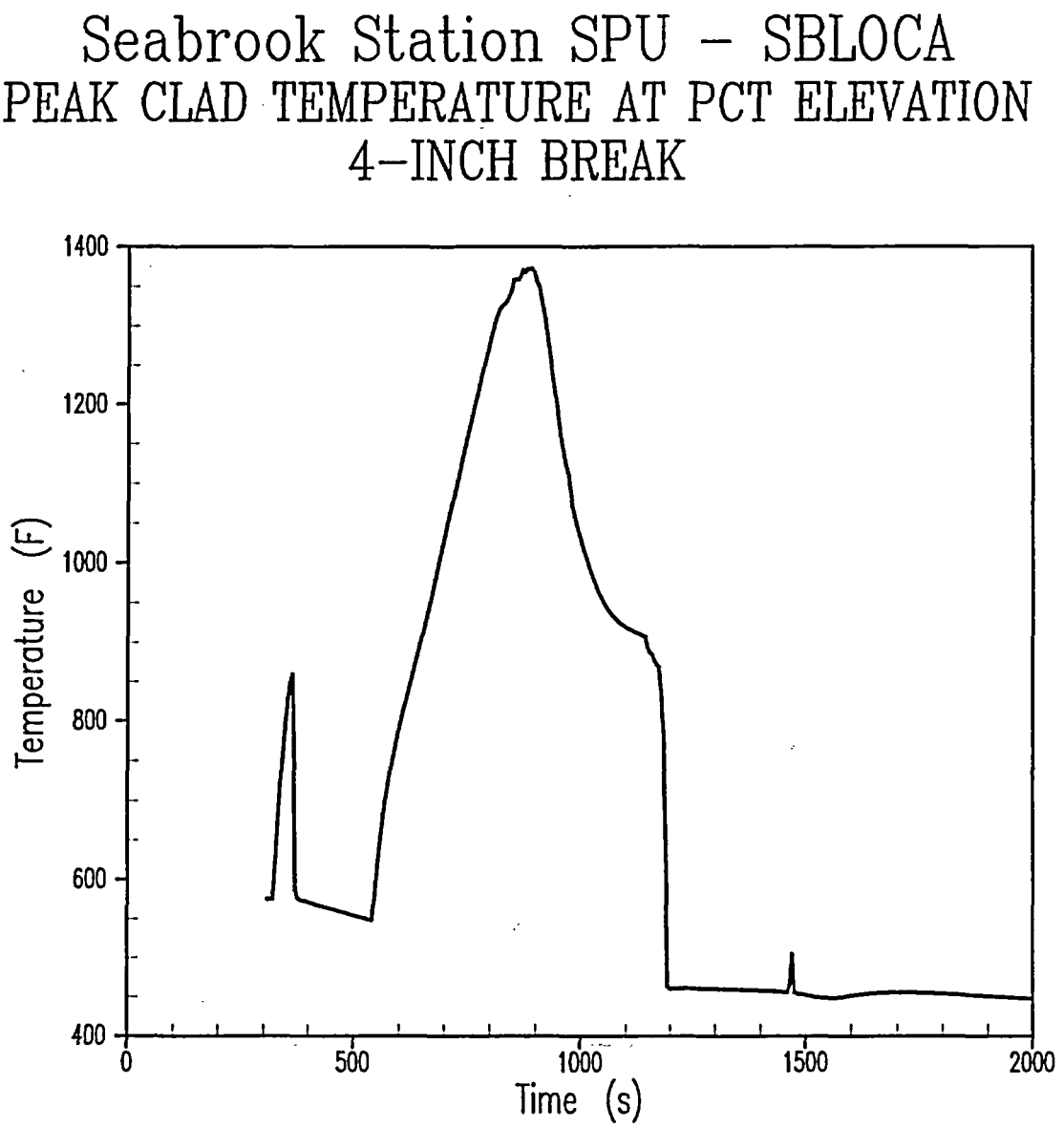


Figure 6.1.2.5-5
4-Inch Break Case, Peak Clad Temperature
at Peak Clad Temperature Elevation (11.25 ft)

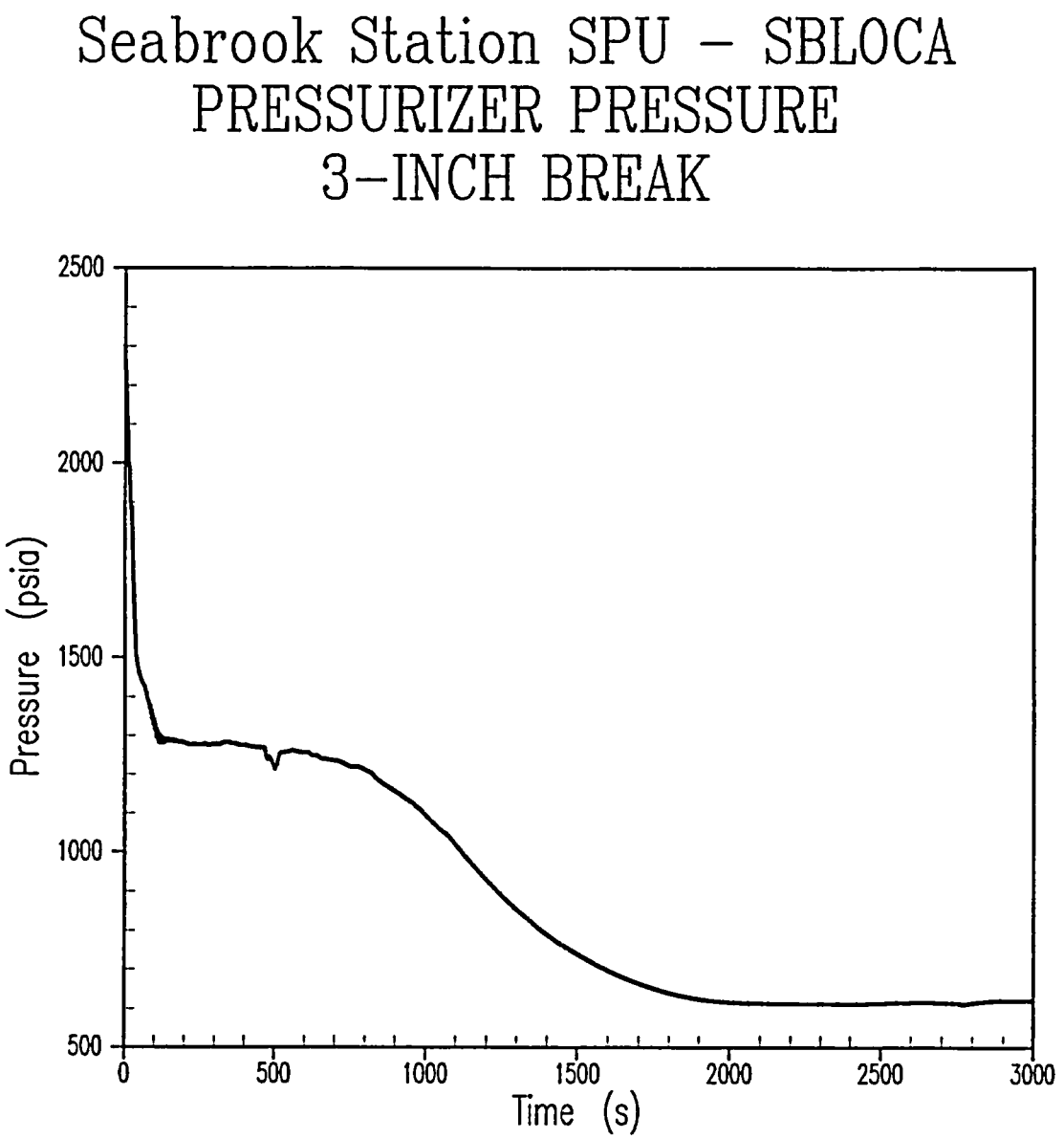


Figure 6.1.2.5-6
3- Inch Break, Pressurizer Pressure

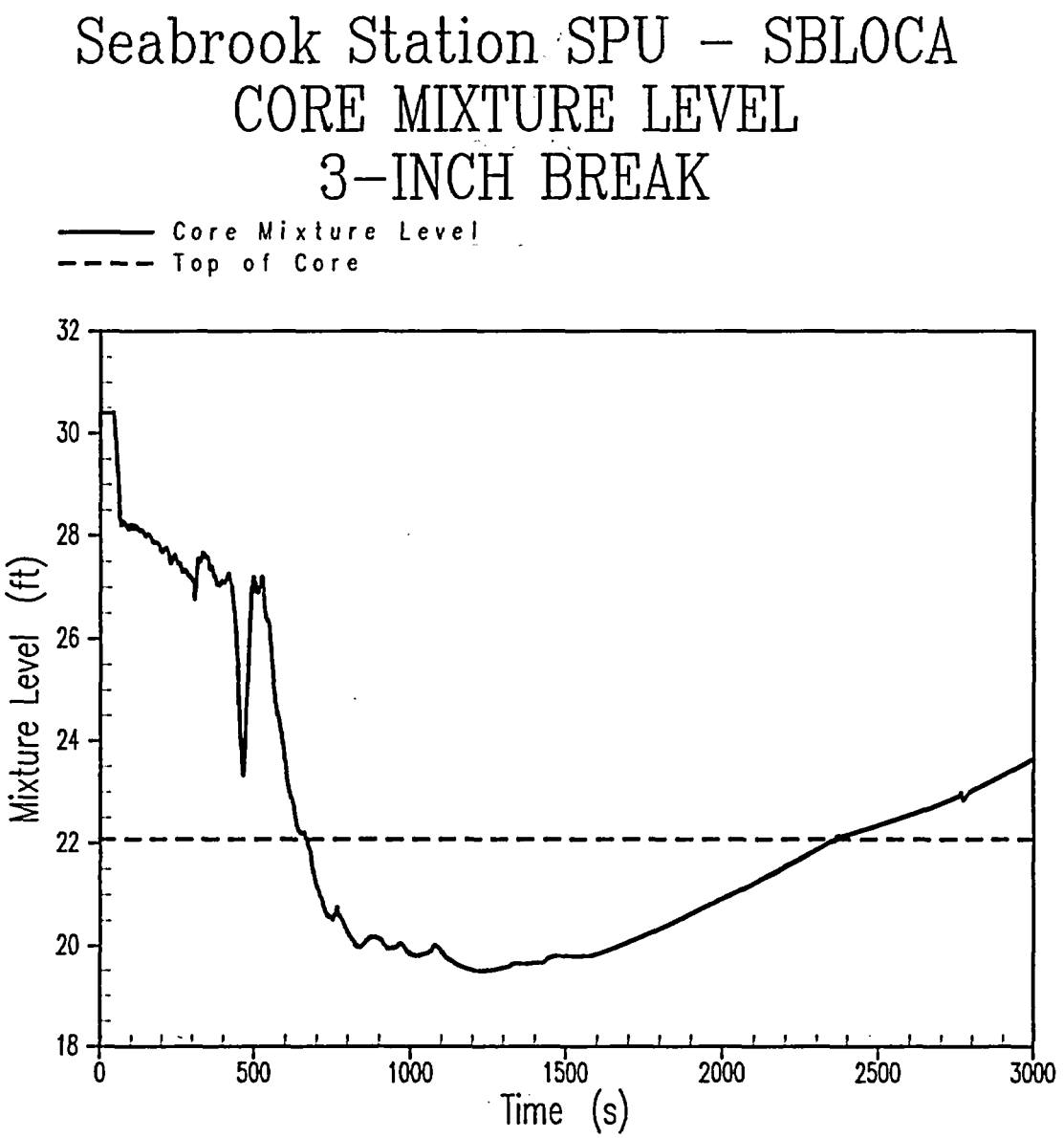


Figure 6.1.2.5-7
3-Inch Break, Core Mixture Level

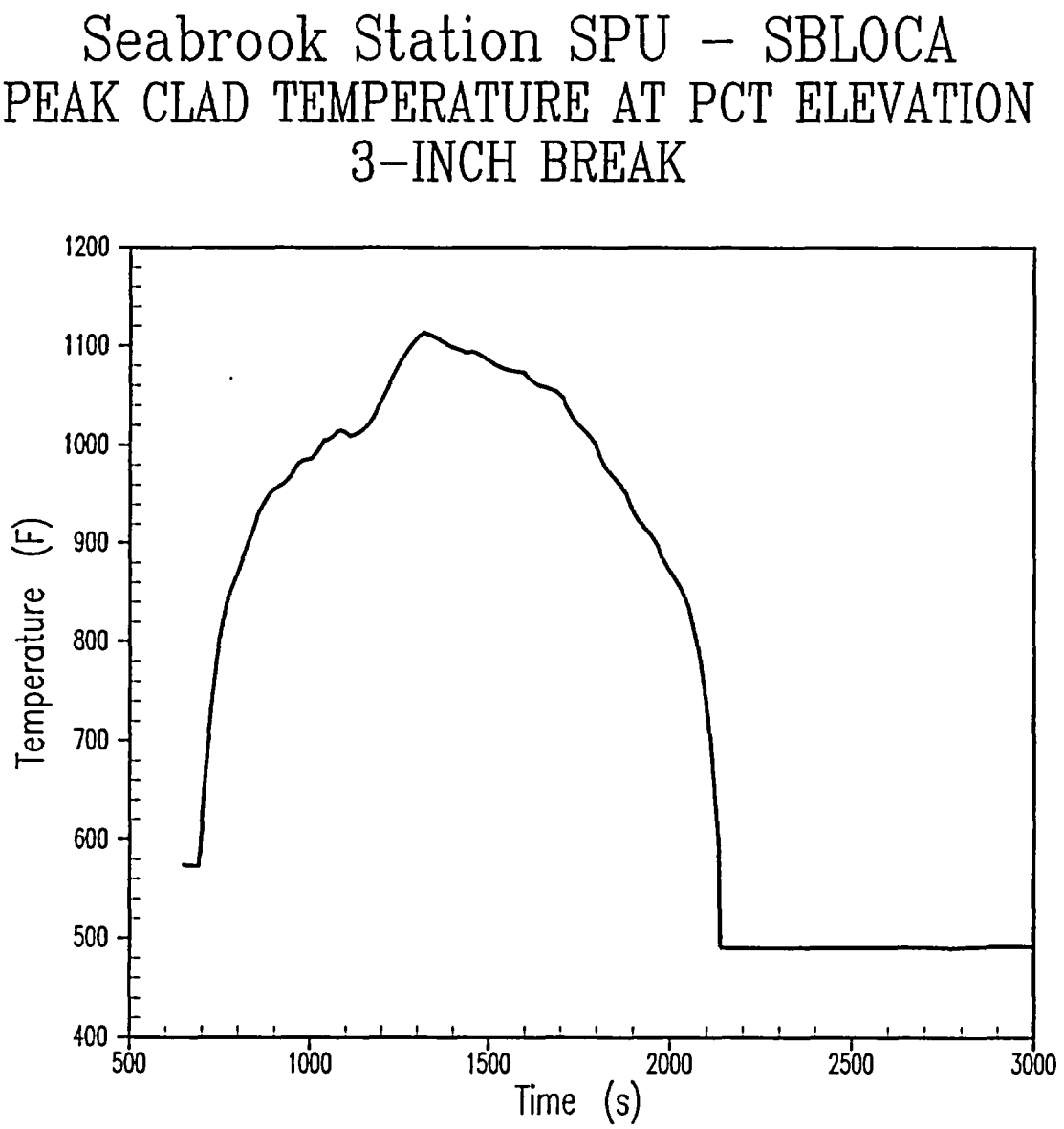


Figure 6.1.2.5-8
3- Inch Break, Peak Clad Temperature
at Peak Clad Temperature Elevation (11.25 ft)

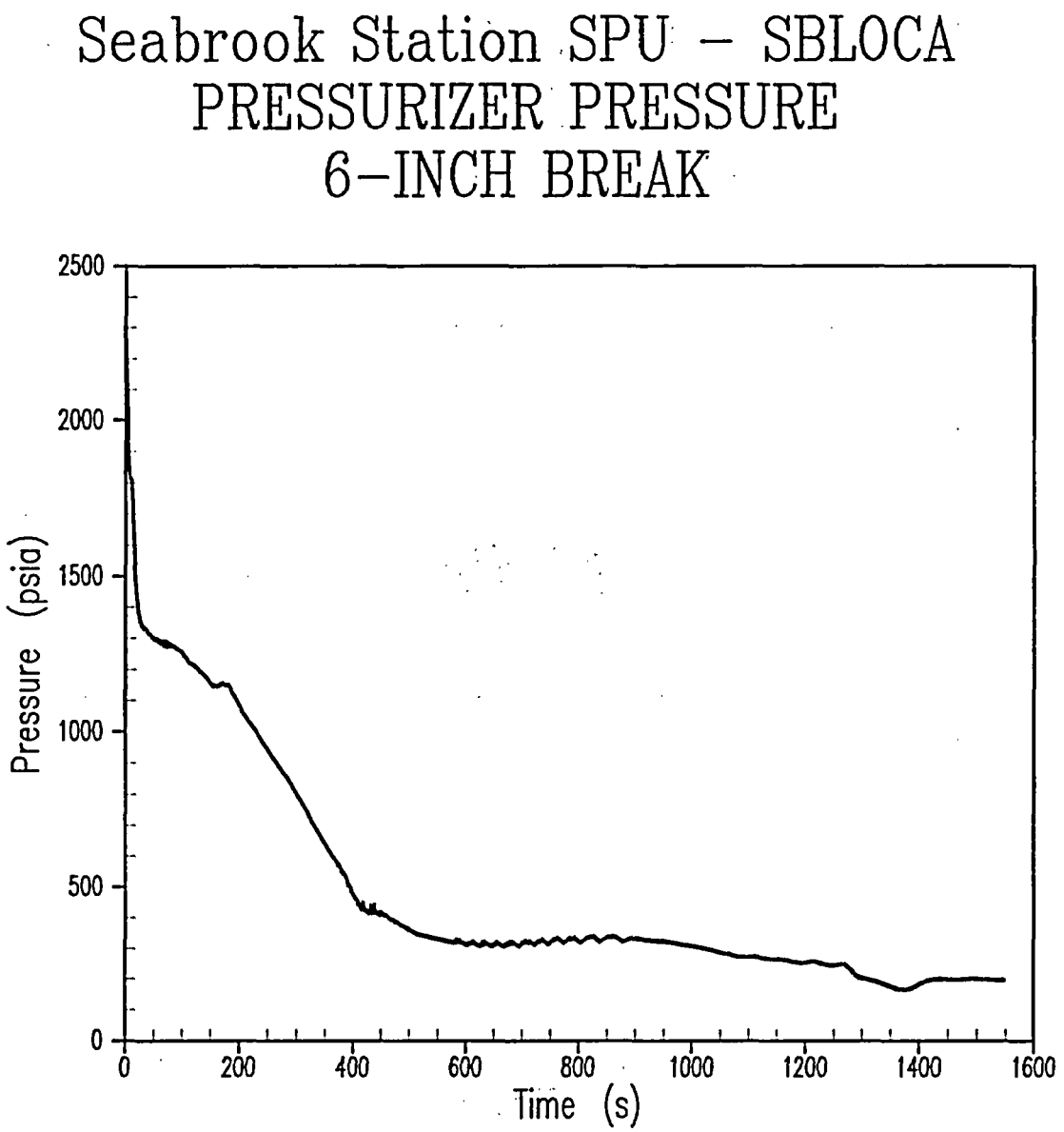


Figure 6.1.2.5-9
6-Inch Break, Pressurizer Pressure

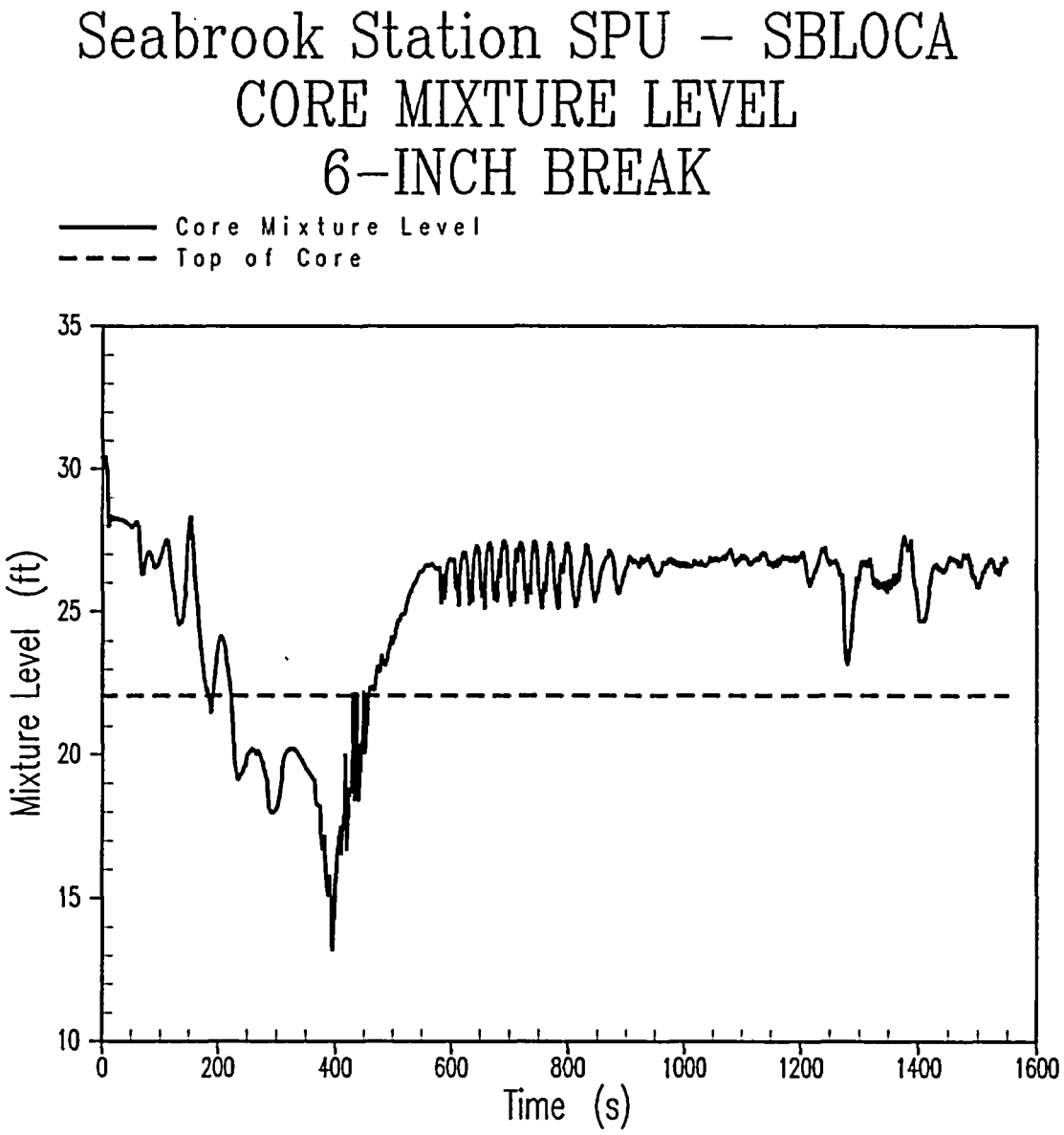


Figure 6.1.2.5-10
6-Inch Break, Core Mixture Level

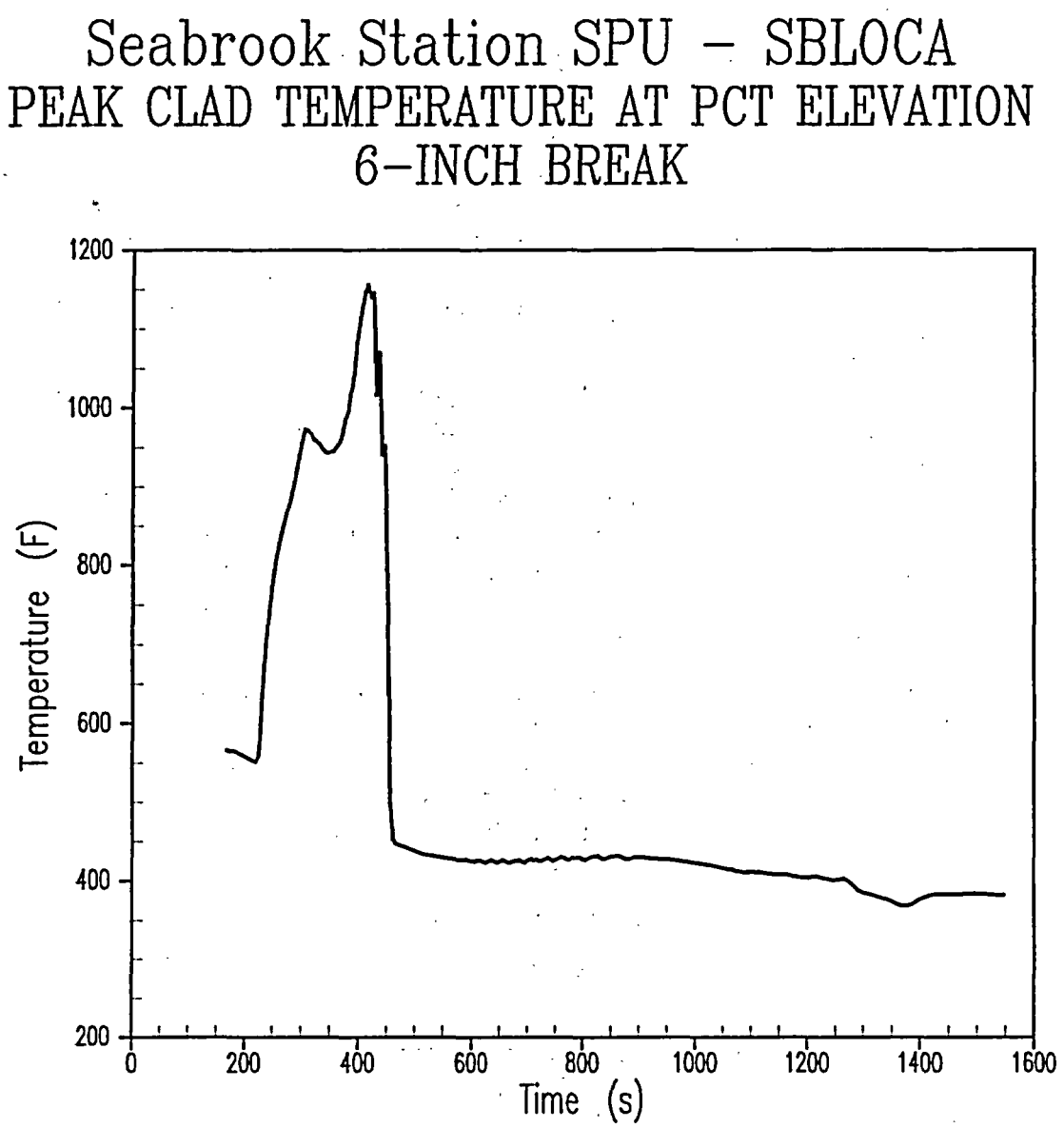


Figure 6.1.2.5-11
6-Inch Break, Peak Clad Temperature
at Peak Clad Temperature Elevation (11.0 ft)

6.2 STEAM GENERATOR TUBE RUPTURE

6.2.1 INTRODUCTION

An analysis of the Seabrook Station design basis steam generator tube rupture event has been performed at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The analysis included an analysis to demonstrate steam generator margin-to-overfill. The radiological consequences of a steam generator tube rupture at Seabrook Station, including the thermal hydraulic analysis to determine mass releases, is summarized in the Alternate Source Term License Amendment Request [Reference 6.2-6]. The steam generator tube rupture analysis was performed using the analysis methodology develop by Westinghouse for the steam generator tube rupture Subgroup of the Westinghouse Owners Group [References 6.2-1 and 6.2-2].

The Seabrook Station response to the steam generator tube rupture event was modeled using the RETRAN computer program [Reference 6.2-5] with conservative assumptions of break size and location, condenser availability, and initial secondary water mass in the ruptured steam generator. The analysis includes the simulation of the operator actions for recovery from a steam generator tube rupture consistent with the Seabrook Station emergency operating procedures. The assumed operator action times are consistent with action times determined by simulator studies performed to support the current analysis of record.

A full-power average temperature (T_{avg}) operating range of 571.0°F to 589.1°F was considered as well as a main feedwater temperature range of 390°F to 452.4°F. The analyses discussed herein assumed that up to 10 percent of the steam generator tubes are plugged. Both the margin to overfill analysis and the radiological consequences analysis conservatively model plant operations. Sensitivity studies were performed to determine the limiting plant conditions for each case.

The following summarizes the plant conditions determined to be limiting for both cases:

- 10% steam generator tube plugging, 589.1°F T_{avg}, 452.4°F main feedwater temperature

The major hazard associated with a steam generator tube rupture event is the radiological consequences resulting from the transfer of radioactive reactor coolant to the secondary side of the ruptured steam generator and subsequent release of radioactivity to the atmosphere. Therefore, an analysis must be performed to assure that the radiological consequences resulting from a steam generator tube rupture are within the allowable guidelines. One of the major concerns for a steam generator tube rupture is the possibility of steam generator overfill and water relief through the atmospheric steam dump valves or main steam safety valves since this could potentially result in a significant increase in the radiological consequences. To demonstrate margin to steam generator overfill an analysis was performed assuming the limiting single failure relative to overfill. The analysis confirmed that the ruptured steam generator does not overfill and water relief does not occur (See LAR Subsection 6.2.2). A thermal and hydraulic analysis was performed to determine the mass transfer input for use in calculating the radiological consequences of a steam generator tube rupture.

The steam generator tube rupture radiological consequences analysis is summarized in the Alternate Source Term License Amendment Request [Reference 6.2-6].

The RETRAN analysis is performed for the time period from the steam generator tube rupture until the primary and secondary pressures are equalized (break flow termination). In the margin to overfill analysis presented in LAR Subsection 6.2.2 the water volume in the secondary side of the ruptured steam generator is calculated as a function of time to demonstrate that overfill does not occur.

6.2.2 MARGIN TO STEAM GENERATOR OVERFILL ANALYSIS

The analysis outlined herein was performed to determine the margin to steam generator overfill for a design basis steam generator tube rupture event for Seabrook Station. The analysis was performed using the RETRAN computer program [Reference 6.2-5] and the methodology developed in Reference 6.2-1, with the plant specific parameters for Seabrook Station. This section includes the methods and assumptions used to analyze the steam generator tube rupture event, as well as the sequence of events for the recovery and the calculated results.

6.2.2.1 Input Parameters and Assumptions

The margin to overfill analysis models the plant operating at a T_{avg} of 589.1°F (upper end of the range), since this increases the time to reach 33% narrow range span level in the ruptured steam generator, which is when isolation of the ruptured steam generator is assumed to occur. The analysis assumes that the plant is operating with a feedwater temperature of 452.4°F (upper end of the range), since this also increases the time to reach 33% narrow range span level in the ruptured steam generator. Maximum (10-percent) tube plugging is assumed in the margin to overfill analysis since this reduces the heat transfer to the ruptured steam generator, minimizing the amount of mass released from the steam generator due to steaming, which in turn reduces the margin to overfill. The reduced heat transfer also prolongs the cooldown period, leading to delayed break flow termination. This has been confirmed via sensitivities performed as part of the analysis.

Design Basis Accident

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet on the outlet (cold leg) side of the steam generator. It was also assumed that a loss-of-offsite power occurs at the time of reactor trip, and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at reactor trip. These modeling assumptions are consistent with the methodology developed by Reference 6.2-1.

The failure of an intact steam generator atmospheric steam dump valve to open during cooldown is assumed, since this failure is limiting with respect to margin to steam generator overfill.

Conservative Assumptions

Plant responses until break flow termination are calculated using the RETRAN computer program. The conservative conditions and assumptions which are found in

Reference 6.2-1 are also used in the RETRAN analysis to determine margin to steam generator overfill for Seabrook with the exception of the following differences.

1. Ruptured Steam Generator Isolation

   The current steam generator tube rupture analysis of record assumes isolation of the ruptured steam generator occurs when the ruptured steam generator water level reaches 33% narrow range span, as documented in the Seabrook Station UFSAR Section 15.6.3. Isolation of the ruptured steam generator includes termination of the emergency feedwater flow and isolation of the ruptured steam generator steamline.

2. Steam Generator Secondary Mass

   Delaying the time to reach 33% narrow range span level in the ruptured steam generator is conservative for the margin to overfill analysis. Based on this a minimum initial ruptured steam generator level is conservative. The analysis modeled the secondary mass in the ruptured steam generator at nominal full power conditions minus 10% for uncertainties. Mass increases to simulate the effect of turbine runback were not included since this would provide non-conservative results.

3. Emergency Feedwater System Operation

   For this analysis, the minimum Emergency Feedwater flow rates to the ruptured and intact steam generators are assumed to be initiated after reactor trip and the coincident loss of offsite power following a 77-second delay. The Emergency Feedwater flow rates are modeled as a function of steam generator pressure and assume that all emergency feedwater pumps operate.

Operator Actions

In the event of a steam generator tube rupture, the operator is required to take actions to stabilize the plant and terminate the primary-to-secondary leakage. The operator actions modeled and their action times are consistent with the current analysis as documented in References 6.2-3 and 6.2-4 and the Seabrook Station UFSAR Section 15.6.3. The operator actions modeled include identification and isolation of the ruptured steam generator, cooldown and depressurization of the Reactor Coolant System to restore inventory and termination of Safety Injection to stop primary-to-secondary leakage. These operator actions are described in detail in LAR Subsection 6.2.2.2.

6.2.2.2 Description of Analyses and Evaluations

The RETRAN analysis results for the Seabrook margin to overfill analysis with operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) are described below. The sequence of events for this transient is presented in LAR Table 6.2.2-2.

Following the tube rupture, reactor coolant flows from the primary into the secondary side of the ruptured steam generator since the primary pressure is greater than the steam generator pressure. In response to this loss of reactor coolant, pressurizer level decreases as shown in LAR Figure 6.2.2-1. The Reactor Coolant System pressure also decreases as shown in LAR Figure 6.2.2-2 as the steam bubble in the pressurizer expands. As the Reactor Coolant System pressure decreases due to the continued

primary-to-secondary leakage, automatic reactor trip occurs on an overtemperature ΔT reactor trip signal at approximately 206 seconds.

After reactor trip, core power rapidly decreases to decay heat levels. The turbine stop valves close and steam flow to the turbine is terminated. The steam dump system is designed to actuate following reactor trip to limit the increase in secondary pressure, but the steam dump valves remain closed due to the loss of condenser vacuum resulting from the assumed loss of offsite power at the time of reactor trip. Thus, the energy transfer from the primary system causes the secondary side pressure to increase rapidly after reactor trip until the steam generator atmospheric dump valves (and safety valves if their setpoints are reached) lift to dissipate the energy, as shown in LAR Figure 6.2.2-3. As a result of the assumed loss of offsite power, main feedwater flow is assumed to be terminated and Emergency Feedwater flow is assumed to be automatically initiated following reactor trip.

The Reactor Coolant System pressure and pressurizer level continue to decrease after reactor trip as energy transfer to the secondary shrinks the reactor coolant and the tube rupture break flow continues to deplete primary inventory. The decrease in Reactor Coolant System inventory results in a low pressurizer pressure Safety Injection signal at approximately 214 seconds. The Safety Injection flow increases the reactor coolant inventory and the Reactor Coolant System pressure trends toward the equilibrium value where the Safety Injection flow rate equals the break flow rate.

Since offsite power is assumed lost at reactor trip, the reactor coolant pumps trip and a gradual transition to natural circulation flow occurs. Immediately following reactor trip the temperature differential across the core decreases as core power decays; however, the temperature differential subsequently increases as the reactor coolant pumps coast down and natural circulation flow develops (see LAR Figure 6.2.2-4). The cold leg temperature trends toward the steam generator temperature as the fluid residence time in the tube region increases. The Reactor Coolant System temperatures continue to slowly decrease due to the continued addition of the emergency feedwater to the steam generators until operator actions are initiated to cool down the Reactor Coolant System.

Major Operator Actions

The following operator actions are required to stabilize the plant and terminate the primary to secondary leakage and are explicitly modeled in this analysis (LAR Table 6.2.2-1). These operator actions and their action times are consistent with the current analysis as documented by References 6.2-3 and 6.2-4, as well as, UFSAR Section 15.6.3.

1. Identify and Isolate the ruptured steam generator

   Recovery actions begin by throttling the emergency feedwater flow to the ruptured steam generator and isolating steam flow from the ruptured steam generator. As indicated previously, the ruptured steam generator is assumed to be isolated when the narrow range level reaches 33 percent narrow range span in the ruptured steam generator. For the Seabrook Station analysis, the level reaches 33 percent narrow range span at approximately 1172 seconds, and thus Emergency Feedwater flow to

and steam flow from the ruptured steam generator are assumed to be isolated at approximately 1172 seconds.

2. Cooldown the Reactor Coolant System to establish subcooling margin

   After isolation of the ruptured steam generator, a 12.5-minute operator action time is imposed prior to initiating the cooldown. After this time, actions are taken to cool the Reactor Coolant System as rapidly as possible by dumping steam from the intact steam generators. Since offsite power is lost, the Reactor Coolant System is cooled by dumping steam to the atmosphere using the atmospheric steam dump valves on two of the intact steam generators. This assumes a failure of one intact steam generator atmospheric steam dump valve to be available for the Reactor Coolant System cooldown. It is assumed that the intact steam generator atmospheric steam dump valves are opened at approximately 1922 seconds for the Reactor Coolant System cooldown. The cooldown is continued until Reactor Coolant System subcooling at the ruptured steam generator pressure is 20°F plus an allowance of 40°F for subcooling uncertainty. When these conditions are satisfied at 3051 seconds, it is assumed that the operator closes the atmospheric steam dump valves to terminate the cooldown. This cooldown is performed so that there will be adequate subcooling in the Reactor Coolant System after the subsequent depressurization of the Reactor Coolant System to the ruptured steam generator pressure. The reduction in the intact steam generator pressure required to accomplish the cooldown is shown in LAR Figure 6.2.2-3, and the effect of the cooldown on the Reactor Coolant System temperature is shown in LAR Figure 6.2.2-4. The pressurizer level and Reactor Coolant System pressure also decrease during this cooldown process due to shrinkage of the reactor coolant, as shown in LAR Figures 6.2.2-1 and 6.2.2-2.

3. Depressurize the Reactor Coolant System to restore inventory

   The Reactor Coolant System depressurization is performed to establish adequate coolant inventory prior to terminating Safety Injection flow. A 3-minute operator action time is included prior to the Reactor Coolant System depressurization. With the reactor coolant pumps stopped, normal pressurizer spray is not available and thus the Reactor Coolant System is depressurized by opening a pressurizer power operated relief valve. The Reactor Coolant System depressurization is initiated at 3231 seconds and continues until any of the following conditions are satisfied: Reactor Coolant System pressure is less than the ruptured steam generator pressure and pressurizer level is greater than the allowance of 5 percent for pressurizer level uncertainty, or pressurizer level is greater than 75 percent, or Reactor Coolant System subcooling is less than the 40°F allowance for subcooling uncertainty. For this case, the Reactor Coolant System depressurization is terminated at 3320 seconds because the Reactor Coolant System pressure is reduced to less than the ruptured steam generator pressure and the pressurizer level is above 5 percent. The Reactor Coolant System depressurization (LAR Figure 6.2.2-2) reduces the break flow as shown in LAR Figure 6.2.2-5 and increases Safety Injection flow to refill the pressurizer, as shown in LAR Figure 6.2.2-1.

4. Terminate safety injection to stop primary-to-secondary leakage

   The previous actions establish adequate Reactor Coolant System subcooling, a secondary side heat sink, and sufficient reactor coolant inventory so that safety injection flow is no longer needed. When these actions have been completed, the safety injection flow must be stopped to prevent re-pressurization of the Reactor Coolant System and to terminate primary-to-secondary leakage. The safety injection flow is terminated at this time if Reactor Coolant System subcooling is greater than the 40°F allowance for subcooling uncertainty, minimum emergency feedwater flow is available, or at least one intact steam generator level is in the narrow range, the Reactor Coolant System pressure is stable or increasing, and the pressurizer level is greater than the 5-percent allowance for uncertainty.

   After depressurization is completed, an operator action time of 5 minutes is assumed prior to safety injection termination. Since the above requirements are satisfied, safety injection termination actions are performed at 3620 seconds. After safety injection termination the Reactor Coolant System pressure begins to decrease as shown in LAR Figure 6.2.2-2.

   The intact steam generator atmospheric steam dump valves, which were used for the cooldown, also automatically open (at about 3855 seconds) to dump steam to maintain the prescribed Reactor Coolant System temperature so that subcooling is maintained. When the atmospheric steam dump valves are opened, the increased energy transfer from primary-to-secondary also aids in the depressurization of the Reactor Coolant System to the ruptured steam generator pressure. The primary-to-secondary leakage continues after safety injection flow is terminated until the Reactor Coolant System and ruptured steam generator pressures equalize.

6.2.2.3 Acceptance Criteria and Results

The analysis is performed to demonstrate that the secondary side of the ruptured steam generator and steam piping up to the main steam safety valves does not completely fill with water.

The primary-to-secondary break flow rate throughout the recovery operations is presented in LAR Figure 6.2.2-5. The available secondary side volume of a single Seabrook steam generator is 5850 ft^3. The water volume in the ruptured steam generator is presented as a function of time in LAR Figure 6.2.2-6. The peak ruptured steam generator water volume of 5409 ft^3 is indicated in LAR Figure 6.2.2-6 showing that there is 441 ft^3 of margin to overfill. Therefore, it is concluded that water relief will not occur for a design basis steam generator tube rupture for Seabrook Station at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), and margin to steam generator overfill is demonstrated.

6.2.2.4 Conclusions

It is concluded that steam generator overfill will not occur for a design basis steam generator tube rupture for Seabrook Station at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

6.2.3 THERMAL AND HYDRAULIC ANALYSIS FOR RADIOLOGICAL CONSEQUENCES

The radiological consequences of a steam generator tube rupture at Seabrook Station are summarized in the Alternate Source Term License Amendment Request [Reference 6.2-6]. The analysis was performed at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and considered the limiting single failure, which maximizes the primary-to-secondary break flow, flashed break flow, and steam releases to the environment.

TABLE 6.2.2-1
OPERATOR ACTION TIMES FOR DESIGN BASIS STEAM GENERATOR TUBE RUPTURE ANALYSIS

Action	Time
Isolate emergency feedwater flow to and steam flow from ruptured steam generator	RETRAN calculated time to reach 33% narrow range level in the ruptured Steam Generator
Operator action time to initiate cooldown	12.5 min. from time of steamline isolation
Cooldown	Calculated by RETRAN
Operator action time to initiate depressurization	3 min. from end of cooldown
Depressurization	Calculated by RETRAN
Operator action time to terminate Safety Injection following depressurization	Maximum of 5 minutes from end of depressurization or time to satisfy termination criteria
Pressure equalization	Calculated by RETRAN

TABLE 6.2.2-2
SEQUENCE OF EVENTS FOR MARGIN TO OVERFILL ANALYSIS

Event	Time (seconds)
Tube rupture	0
Reactor trip (overtemperature ΔT)	206
Safety injection actuation (low pressurizer pressure)	214
Emergency feedwater initiated	283
Isolate emergency feedwater to ruptured steam generator	1172
Isolate ruptured steam generator steam line	1172
Initiate cooldown with intact steam generators	1922
Terminate cooldown	3051
Initiate depressurization with pressurizer power operated relief valves	3231
Terminate depressurization	3320
Ruptured steam generator fills	N/A
Stop safety injection flow	3620
Steam relief to maintain subcooling	3855
Break flow terminated	4960

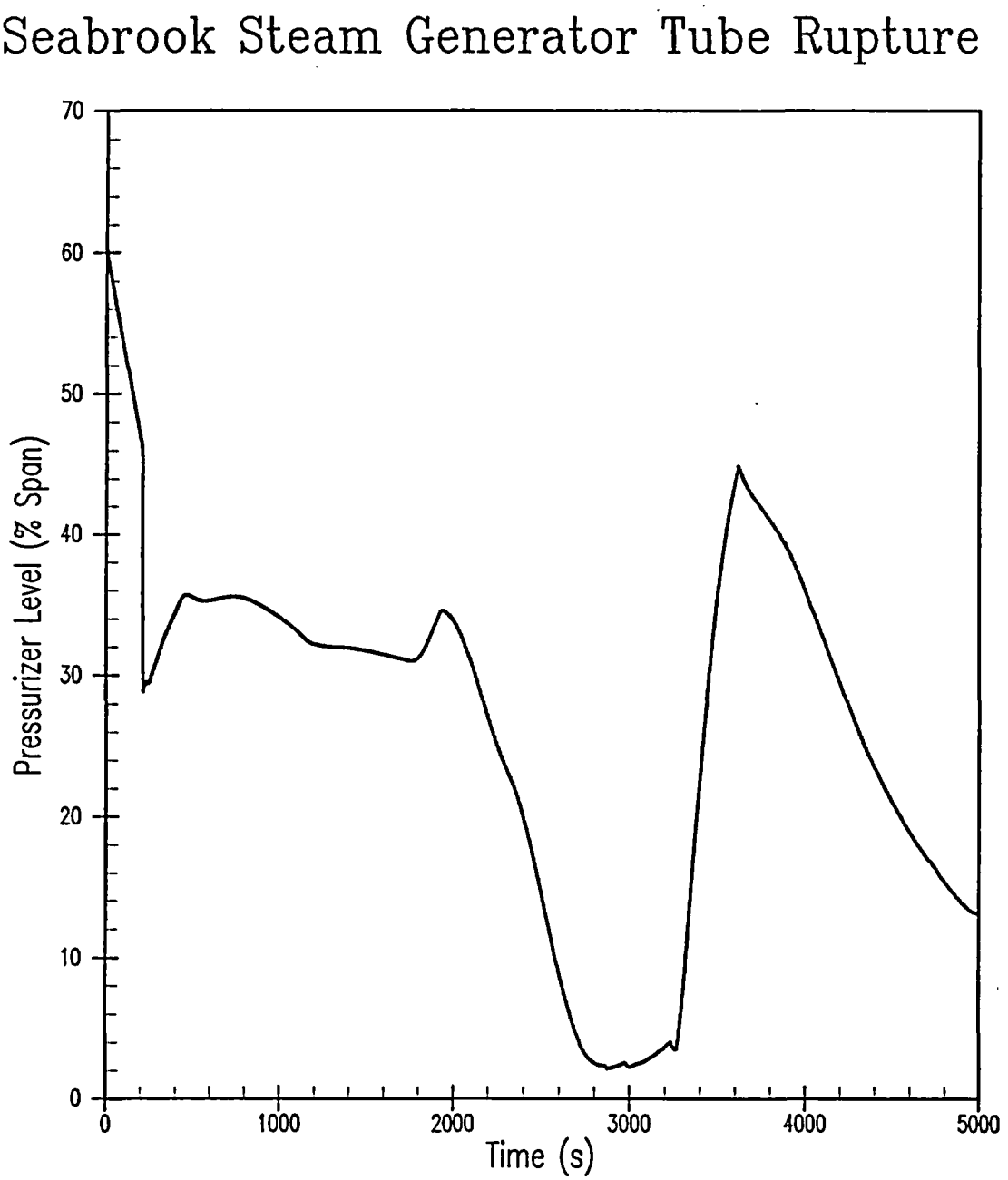


Figure 6.2.2-1
Margin to Overfill Analysis
Pressurizer Level

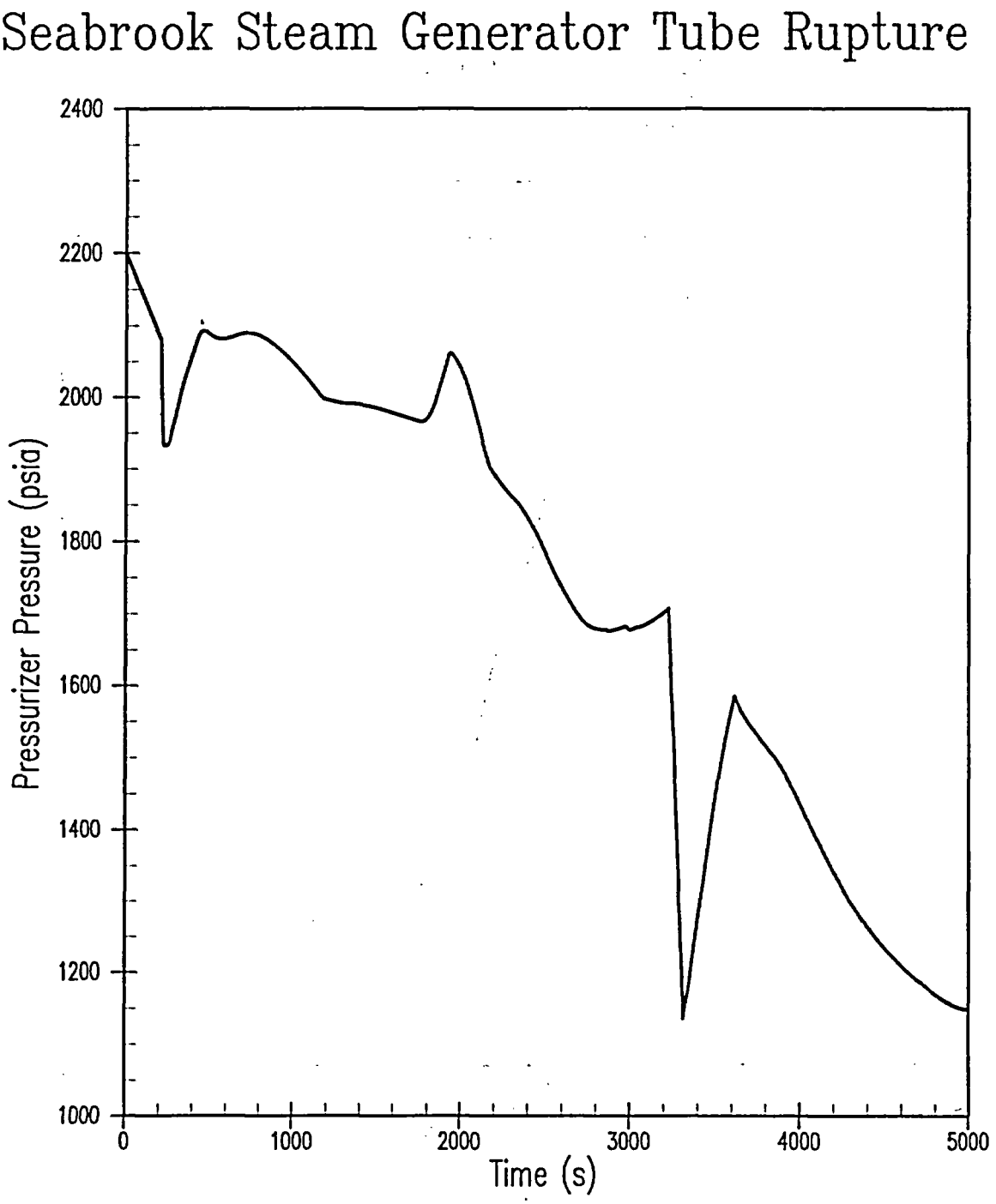


Figure 6.2.2-2
Margin to Overfill Analysis
Pressurizer Pressure

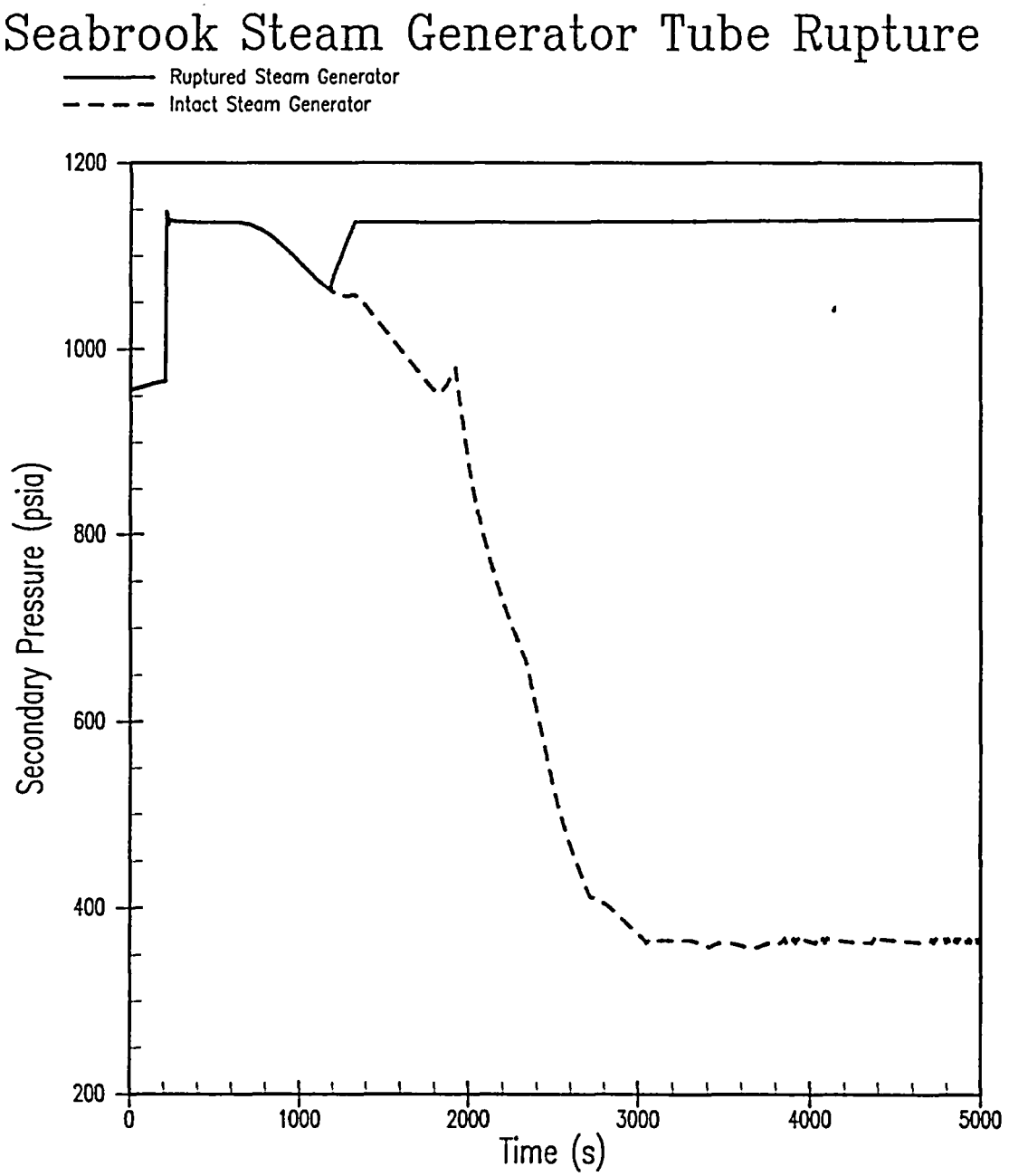


Figure 6.2.2-3
Margin to Overfill Analysis
Secondary Pressure

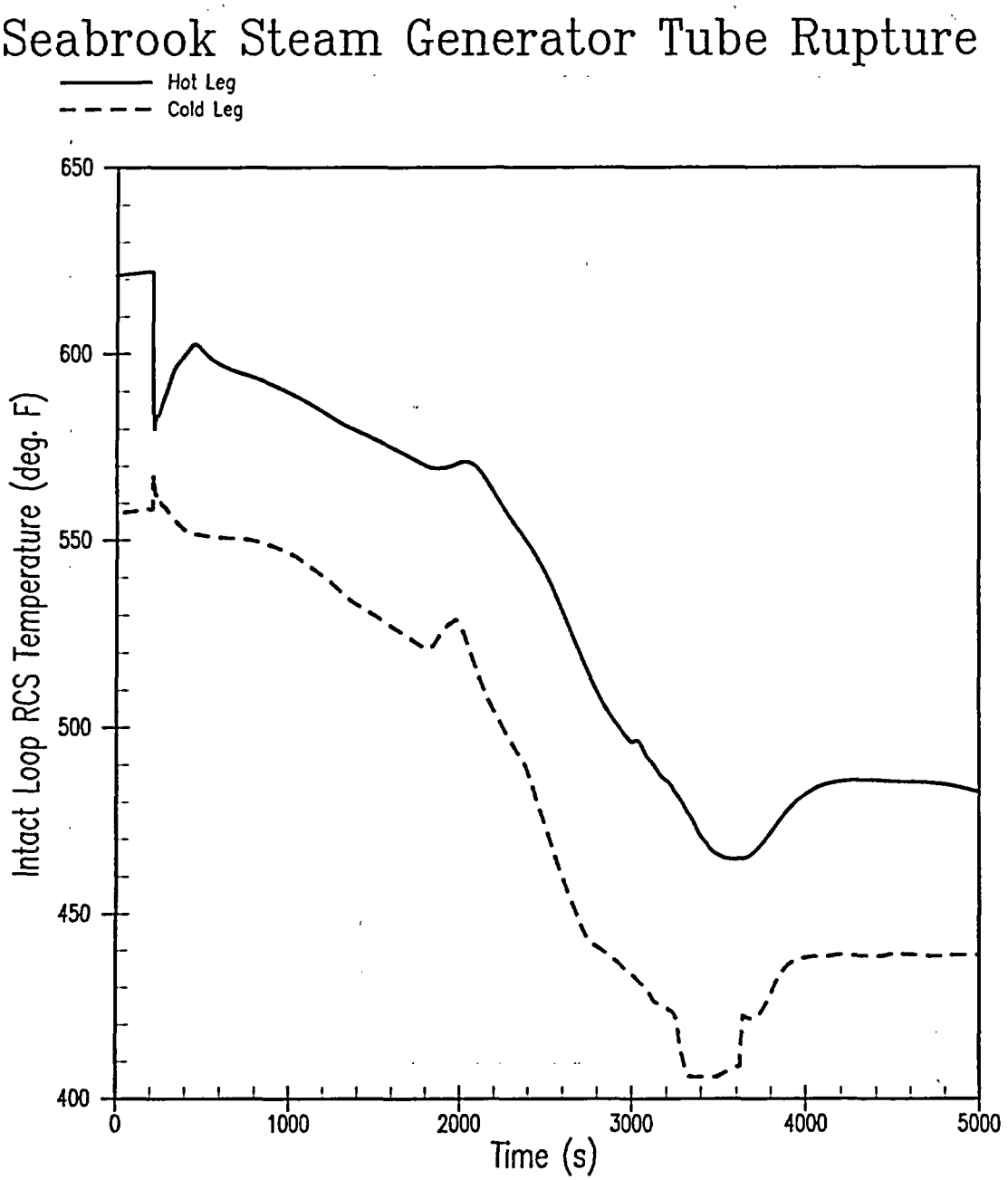


Figure 6.2.2-4
Margin to Overfill Analysis
Intact Loop Hot & Cold Leg Temperatures

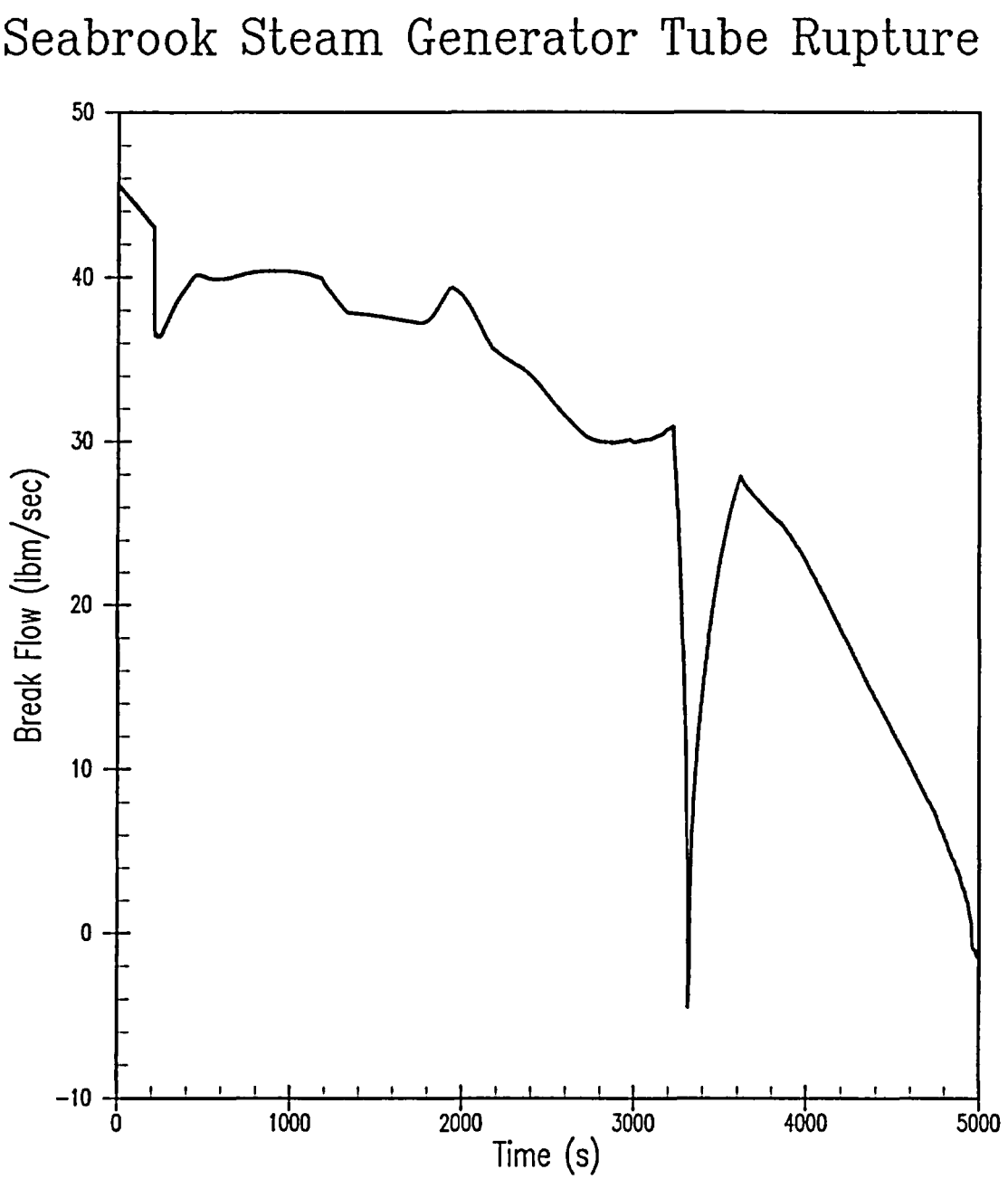


Figure 6.2.2-5
Margin to Overfill Analysis
Primary-to-Secondary Break Flow

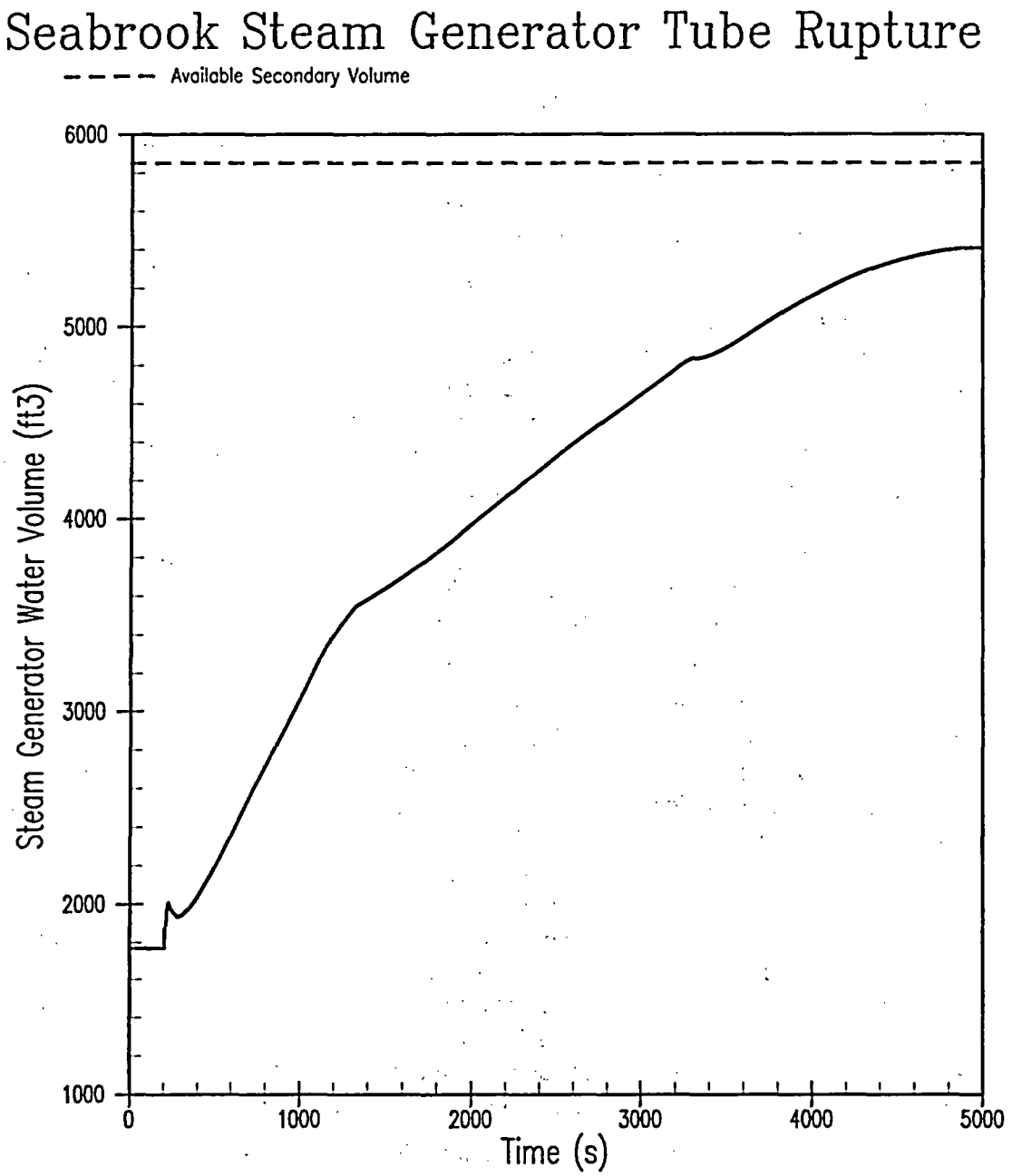


Figure 6.2.2-6
Margin to Overfill Analysis
Ruptured Steam Generator Water Volume

6.3 NON-LOCA EVENTS

6.3.1 INTRODUCTION

To support the Seabrook Station SPU, all Seabrook Station UFSAR Chapter 15 non-loss of coolant accident (non-LOCA) analyses were evaluated to determine the acceptability of plant operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The SPU conditions addressed are those defined in LAR Section 2.0 for the Seabrook Station SPU. The non-LOCA events considered herein are listed in LAR Table 6.3.1-1, along with 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 [Reference 6.3-1]) computer code that is based on the same methods and methodology used in the current non-LOCA safety analyses using the LOFTRAN [Reference 6.3-2] code. For certain applications, RETRAN was used in combination with other computer codes, such as VIPRE-01 [Reference 6.3-4] for reactor core subchannel thermal-hydraulic calculations, a neutronic code such as ANC [Reference 6.3-12], and a fuel performance code such as PAD (as described in LAR Section 1.2). RETRAN is approved for use in non-LOCA safety analysis by the Nuclear Regulatory Commission in the Safety Evaluation Report for WCAP-14882-P-A [Reference 6.2-5].

LAR Table 6.3.1-4 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 Nuclear Regulatory Commission for use on each of the non-LOCA events that were analyzed using RETRAN for the SPU Program (documented in Table 1 of the SER of WCAP-14882-P-A [Reference 6.2-5]). The RETRAN model used in the Seabrook non-LOCA SPU safety analyses simulates a Westinghouse four-loop plant design, applicable to Seabrook Station, 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 LAR Subsections 6.3.2 through 6.3.9. In performing the evaluations for reload cores, Westinghouse uses approved methodology [Reference 6.3-15], which requires conservative code input so as to bound the expected conditions for subsequent reloads.

Where applicable, the Revised Thermal Design Procedure methodology discussed in WCAP-11397-P-A [Reference 6.3-8] is used in the non-LOCA analyses. The Revised Thermal Design Procedure methodology statistically convoluted the uncertainties of the plant operating parameters (for example, power, temperature, pressure, and flow) into the design limit departure from nucleate boiling ratio value. These design limit departure from nucleate boiling ratio values are then used to determine the safety analysis limit departure from nucleate boiling ratio values that are used as an acceptance criterion in the departure from nucleate boiling ratio related non-LOCA analyses.

In conjunction with the SPU, the non-LOCA safety analyses supported several other related changes that directly affect the Seabrook Station UFSAR Chapter 15 non-LOCA safety analyses. These changes are summarized in the LAR sections that follow.

6.3.1.1 SPU FEATURES

The changes in plant conditions that are considered to be directly associated with the SPU are shown in LAR Section 2.0, and discussed below.

The analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). This corresponds to a core power of 3659 MWt, and a rod average linear power to 5.840 kW/ft.

Thermal design flow has been reduced to 374,400 gpm for the SPU. The minimum measured flow, used in conjunction with the statistical Revised Thermal Design Procedure departure from nucleate boiling methodology has been reduced to 383,800 gpm. Core bypass flow fractions of 6.8 percent (non-statistical) and 8.3 percent (statistical) are assumed.

The non-LOCA safety analyses now support a T_{avg} window. The maximum reactor vessel average coolant temperature (T_{avg}) is 589.1°F. The minimum full-power T_{avg} analyzed is 571.0°F. The non-LOCA safety analyses now support a range of main feedwater temperatures. The full-power feedwater temperature range is 390.0 to 452.4°F. The previous analyses supported a full-power T_{avg} of 588.5°F and a full-power feedwater temperature of 440.0°F. The assumed feedwater temperature at hot zero power conditions remains at 100°F. Feedwater temperatures at part-power conditions increases proportionally with power between hot zero power and full-power conditions.

The maximum assumed steam generator tube plugging levels have been increased from 8-percent uniform/30-percent peak to 10-percent uniform for the Model F steam generators. Asymmetric reactor coolant loop flow conditions consistent with a maximum 10-percent loop-to-loop steam generator tube plugging are assumed.

6.3.1.2 OVERTEMPERATURE ΔT AND OVERPOWER ΔT REACTOR TRIP SETPOINTS

The overtemperature ΔT and overpower ΔT reactor trip functions are assumed to be available in several non-LOCA transient analyses to ensure that the departure from nucleate boiling design basis and the fuel centerline melting design basis are satisfied. The overtemperature ΔT and overpower ΔT reactor trip safety analysis setpoints have been generated assuming steady-state conditions and are based on a number of inputs, including the nominal core thermal power and the core thermal safety limits. These core limits are applicable to robust fuel assembly fuel, assuming the analyzed SPU core power of 3659 MWt (3678 MWt NSSS power level) and a nominal Reactor Coolant System pressure of 2250 psia. The core thermal limits used to calculate the overtemperature ΔT / overpower ΔT setpoints are provided in LAR Figure 6.3.1-1 and in revised Technical Specification Figure 2.2-1. These figures are applicable to the robust fuel assemblies. The core thermal limits presented in LAR Figure 6.3.1-1 are significantly improved for the SPU because of the use of the WRB-2M correlation (discussed in LAR Section 7.1). The overtemperature ΔT and overpower ΔT trip

setpoints calculated for the SPU are illustrated in LAR Figure 6.3.1-2. These setpoints remain constant (with the exception of reference average temperatures (T'), which depends on the operating T_{avg} chosen) and are applicable across the entire range of Reactor Coolant System average temperatures being considered for this program (that is, T_{avg} between 571.0°F and 589.1°F).

The adequacy of these setpoints is confirmed in the analyses of those events that credit these functions for accident mitigation by showing that the departure from nucleate boiling design basis is met. The revised safety analysis setpoints are based upon the assumption that the reference average temperature (T') used in the overtemperature ΔT and overpower ΔT setpoint equations correspond to the selected operating temperature within the T_{avg} window. A temperature deviation is assumed to account for loop-to-loop average temperature variations caused, in part, by hot leg and cold leg streaming. This assumption is necessary to ensure that the actual plant conditions used to generate an overtemperature ΔT and/or overpower ΔT trip signal are bounded by the assumptions made in the safety analyses.

The boundaries of operation defined by the overtemperature ΔT and overpower ΔT trips are represented as "protection lines" in LAR Figure 6.3.1-2. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions, a trip would occur well within the area bounded by these lines. These protection lines are based upon the safety analysis limit overtemperature ΔT and overpower ΔT setpoint values, which are essentially the Technical Specification nominal values with allowances for the adverse instrumentation behavior, setpoint errors, and acceptable drift between instrument calibration. The departure from nucleate boiling lines represent the locus of conditions for which the departure from nucleate boiling ratio equals the limit value (in this case, 1.47 for both typical and thimble cells). All points below and to the left of a departure from nucleate boiling line for a given pressure have a departure from nucleate boiling ratio greater than the safety analysis limit departure from nucleate boiling ratio value.

The area of permissible operation (power, temperature, and pressure) is bounded by the combination of reactor trips: high neutron flux (fixed setpoint); high and low Reactor Coolant System pressure (fixed setpoints); overtemperature ΔT and overpower ΔT (variable setpoints), and the opening of the main steam safety valves, which limit the maximum Reactor Coolant System average temperature.

The changes associated with the overtemperature ΔT and overpower ΔT setpoints have been confirmed as being acceptable by showing that the departure from nucleate boiling design basis is met for the departure from nucleate boiling -limited transient analyses discussed herein.

6.3.1.3 NEUTRONICS / REACTIVITY MODELING

To support future reload design activities with uprated core power and to support several event-specific uprating analyses, several neutronics-related analysis input assumptions have been changed to support the uprate.

To facilitate future reload evaluations, the isothermal temperature coefficient, ejected rod worth, delayed neutron fraction, and Doppler defect values assumed in the rod ejection analysis were adjusted to offset the effect the SPU has on the end-of-life/hot zero power case. The rod ejection analysis is presented in LAR Section 6.3.5.7.

6.3.1.4 OTHER MAJOR ASSUMPTIONS

LAR Table 6.3.1-2 lists the non-LOCA initial condition assumptions used. Other major assumptions considered in the non-LOCA transient analyses are discussed below:

1. A ± 3-percent setpoint tolerance and a 5 psi accumulation have been considered in the modeling of the main steam safety valves. Justification for the use of the 5 psi accumulation instead of modeling accumulation is based on test data documented in WCAP-10105 and WCAP-12910 [References 6.3-10 and 6.3-7, respectively]. Staggered lift setpoints are modeled for the main steam safety valves (using plant-specific Technical Specification setpoints).
2. The pressurizer safety valves are modeled assuming a ± 3-percent setpoint tolerance.
3. Consistent with the Seabrook Station Technical Specifications, a + 5 pcm/°F moderator temperature coefficient is assumed up to 70-percent power (Technical Specification 3.1.1.3). A zero moderator temperature coefficient is modeled at 100% power. Between 70% power and 100% power, the moderator temperature coefficient ramps linearly from +5 pcm/°F to 0 pcm/°F.
4. The fission product contribution to decay heat assumed in the non-LOCA analyses is the American Nuclear Society (ANS)-5.1-1979 residual decay heat model discussed in Reference 6.3-11, including two standard deviations of uncertainty.
5. Since Seabrook Station is not licensed to operate at-power with a reactor coolant pump out of service (Technical Specification 3/4.4.1), the non-LOCA analyses for the SPU only address four-loop operation.
6. The assumed core bypass flow percentages are 6.8 percent for Revised Thermal Design Procedure analyses and 8.3 percent for Standard Thermal Design Procedure analyses.
7. The impact of a T_{avg} coastdown within the T_{avg} window of 589.1°F and 571.0°F was evaluated. The evaluation assumes that during the coastdown, T_{avg} will be allowed to fall and full power will be maintained by allowing the turbine valves to go wide open. At that point, both power and T_{avg} will drop with the turbine valves held wide open. When the power/T_{avg} combination gets to the minimum allowed T_{avg} program (571.0°F), the T_{avg} will drop linearly with power to 557°F at zero power. The T' and T" settings in the overtemperature ΔT and overpower ΔT reactor trip functions, respectively, will not need to be reset during the coastdown. This evaluation will conservatively bound actual plant operation during a T_{avg} coastdown.
8. Steam Generator level control bias effects described in NSAL-02-5, Revision 1 [Reference 6.3-17] have been accounted for as necessary (e.g., Loss of Normal Feedwater Flow, Feedwater System Pipe Break, Excessive Heat Removal Due to

Feedwater System Malfunctions). Note that several analyses are not sensitive to secondary side initial conditions and therefore, the steam generator level control bias effects need not be accounted for in these analyses.

6.3.1.5 REACTOR PROTECTION SYSTEM AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM FUNCTIONS ASSUMED IN ANALYSES

LAR Table 6.3.1-3 contains a list of the different Reactor Protection System and Engineered Safety Features Actuation System functions credited in the non-LOCA transient analyses. The safety analysis setpoints, as well as the time delays associated with each of these functions, are also presented in LAR Table 6.3.1-3. The overtemperature ΔT trip functions are illustrated by LAR Figure 6.3.1-2.

6.3.1.6 ROD CLUSTER CONTROL ASSEMBLIES INSERTION CHARACTERISTICS

The negative reactivity insertion following a reactor trip is a function of the acceleration of the rod cluster control assemblies and the variation in rod worth as a function of rod position. With respect to the non-LOCA transient analyses, a critical parameter is the time from beginning of rod cluster control assemblies insertion to dashpot entry, or approximately 85 percent of the rod cluster control assemblies travel, although negative reactivity addition continues to be modeled until rods are completely inserted. For the non-LOCA analyses, the assumed insertion time from fully withdrawn to dashpot entry is the Technical Specification limit of 2.4 seconds.

Three figures relating to rod cluster control assemblies drop time and reactivity worth are presented in this LAR. The rod cluster control assemblies position (percent insertion) versus the time from release is presented in LAR Figure 6.3.1-3. LAR Figure 6.3.1-4 shows the normalized reactivity versus percent of rod cluster control assemblies insertion. The normalized reactivity worth assumed in the safety analyses is shown in LAR Figure 6.3.1-5. LAR Figure 6.3.1-5 is created by combining LAR Figures 6.3.1-3 and 6.3.1-4 with the Technical Specification limit rod drop time of 2.4 seconds.

6.3.1.7 REACTIVITY COEFFICIENTS

The transient response of the Reactor Coolant System is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. Depending upon event-specific characteristics, conservatism dictates the use of either maximum or minimum reactivity coefficient values. Justification for the use of the reactivity coefficient values is treated on an event-specific basis. LAR Table 6.3.1-5 presents the core kinetics parameters and reactivity feedback coefficients assumed in the non-LOCA SPU analyses.

6.3.1.8 EVENT CLASSIFICATION

The non-LOCA accidents are classified by the American Nuclear Society as Condition I, II, III, or IV events. The American Nuclear Society 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 the 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 Reactor Coolant System or containment as fission product barriers can occur. The release of radioactive materials to unrestricted areas may exceed 10 CFR 20 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 limits of 10 CFR 50.67. 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 LAR Section 2.0.

6.3.1.9 COMPUTER CODES UTILIZED

Summary descriptions of the principal computer codes used in the non-LOCA transient analyses are provided below. LAR Table 6.3.1-4 lists the computer codes used in each of the non-LOCA analyses.

6.3.1.9.1 FACTRAN

FACTRAN [Reference 6.3-13] 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 transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel

6.3.1.9.2 RETRAN

RETRAN [Reference 6.3-1] is used for studies of transient response of a pressurized water reactor 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, reactor coolant pumps, 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 Reactor Protection System simulated in the code includes reactor trips on high neutron flux, overtemperature ΔT and overpower ΔT, low Reactor Coolant System 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 Safety Injection System, including the accumulators, may also be modeled. RETRAN approximates the transient value of departure from nucleate boiling ratio based on input from the core thermal safety limits.

6.3.1.9.3 LOFTRAN

Transient response studies of a pressurized water reactor to specified perturbations in process parameters use the LOFTRAN [Reference 6.3-2] computer code. This code simulates a multi-loop system by a model containing the reactor vessel, hot- and cold-leg piping, steam generators (tube and shell sides), the pressurizer and the pressurizer heaters, spray, relief valves, and safety valves. LOFTRAN also includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and rods. The secondary side of the steam generator uses a homogeneous, saturated mixture for the thermal transients. The code simulates the Reactor Protection System, which includes reactor trips on high neutron flux, overtemperature ΔT and overpower ΔT, high and low pressurizer pressure, low Reactor Coolant System flow, lo-lo steam generator water level, and high pressurizer level. Control systems are also simulated including rod control, steam dump, and pressurizer pressure control. The Safety Injection System, including the accumulators, may also be modeled. LOFTRAN also approximates the transient value of departure from nucleate boiling ratio based on the input from the core thermal safety limits.

6.3.1.9.4 ADVANCED NODAL CODE

Advanced Nodal Code [Reference 6.3-12] is an advanced nodal code capable of two-dimensional and three-dimensional neutronics calculations. Advanced Nodal Code is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients,

etc. In addition, three-dimensional Advanced Nodal Code validates one-dimensional and two-dimensional 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 as well.

6.3.1.9.5 TWINKLE

TWINKLE [Reference 6.3-3] is a multi-dimensional spatial neutron kinetics code. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 8,000 spatial points and performs steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. The code provides various outputs, such as channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, and fuel temperatures. It also predicts the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

6.3.1.9.6 VIPRE

The VIPRE computer program [Reference 6.3-4] performs thermal-hydraulic calculations. This code calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and departure from nucleate boiling ratio distributions along flow channels within a reactor core.

6.3.1.10 EVENTS EVALUATED OR ANALYZED

The effects of the SPU implementation on each of the Seabrook Station UFSAR transients listed in LAR Table 6.3.1-1 were evaluated or analyzed. These transient evaluations and analyses demonstrate that all applicable safety analysis acceptance criteria continue to be met for the SPU implementation at Seabrook Station. LAR Table 6.3.1-1 summarizes the results obtained for each of the non-LOCA transient analyses.

TABLE 6.3.1-1
NON-LOCA ANALYSIS LIMITS AND SELECTED ANALYSIS RESULTS

UFSAR Section	Event Description	Result Parameter	Selected Result	
			Analysis Limit	(Limiting Case)
15.1.1	Feedwater Temperature Reduction Incident	Bounded by excessive load increase		
15.1.2	Excessive Heat Removal Due to Feedwater System Malfunctions	Minimum departure from nucleate boiling ratio (Revised Thermal Design Procedure, WRB-2M) Hot zero power FWM Bounded by hot zero power steamline break	1.47	2.15
15.1.3	Excessive Load Increase Incident	Minimum departure from nucleate boiling ratio (Revised Thermal Design Procedure, WRB-2M)	1.47	>1.47
15.1.5	Steam Line Break (Core response only)	Minimum departure from nucleate boiling ratio (non- Revised Thermal Design Procedure, W-3)	1.50	1.79 - thimble 1.87 - typical
15.2.2 and 15.2.3	Loss of External Electrical Load / Turbine Trip	Minimum departure from nucleate boiling ratio (Revised Thermal Design Procedure, WRB-2M)	1.47	1.83
		Peak Reactor Coolant System pressure, psia	2748.5	2681.9
		Peak Main Steam System pressure, psia	1318.5	1302.8
15.2.6	Loss of AC Power to the Plant Auxiliaries	Maximum pressurizer water volume ft^3	1834.4	1463
15.2.7	Loss of Normal Feedwater	Maximum pressurizer water volume, ft^3	1834.4	1175
15.2.8	Feedwater System Pipe Break	Margin to hot leg saturation	0.0	0.0
15.3.1 and 15.3.2	Loss of Reactor Coolant Flow partial loss of flow (PLOF) complete loss of flow (CLOF underfrequency (UF)	Minimum departure from nucleate boiling ratio (Revised Thermal Design Procedure, WRB-2M)	1.47	2.17 (PLOF) 2.06 (CLOF) 2.00 (UF)
15.3.3 – 15.3.4	Locked Rotor	Rods-in- departure from nucleate boiling (Revised Thermal Design Procedure, WRB-2M)	See Section 6.3.4.2	
		Peak Reactor Coolant System pressure, psia	2748.5	2544
		Peak cladding temperature, °F	2700	1650
		Maximum Zirc-water reaction, %	16	0.20

TABLE 6.3.1-1 (continued)
NON-LOCA ANALYSIS LIMITS AND SELECTED ANALYSIS RESULTS

UFSAR Section	Event Description	Result Parameter	Selected Result	
			Analysis Limit	(Limiting Case)
15.4.1	Uncontrolled rod control cluster assembly withdrawal from a subcritical condition	Minimum departure from nucleate boiling ratio below first mixing vane grid (non- Revised Thermal Design Procedure, W-3 correlation and WRB-2. See LAR Subsection 7.1.4.2.7)	1.30 - typical 1.30 - thimble	1.46 - typical 1.34 - thimble
		Maximum fuel centerline temperature, °F	4800	2536
15.4.2	Uncontrolled rod control cluster assembly withdrawal at power	Minimum departure from nucleate boiling ratio (Revised Thermal Design Procedure, WRB-2M)	1.47	1.54
		Peak Reactor Coolant System pressure, psia	2748.5	< 2748.5
		Peak Main Steam System pressure, psia	1318.5	1281.0
15.4.3	Rod control cluster assembly misalignment	Minimum departure from nucleate boiling ratio (Revised Thermal Design Procedure, WRB-2M)	1.47	>1.47
15.4.4	Startup of an Inactive Reactor Coolant Loop – Precluded by Technical Specifications			
15.4.6	Chemical and Volume Control System Malfunction			
	(at power)	Minimum time to loss of shutdown margin, minutes	15	32.99 (manual) 36.99 (auto)
	(during startup)	Minimum time to loss of shutdown margin, minutes	15	38.94
	(hot standby)	Minimum time to loss of shutdown margin, minutes	15	15.78
	(hot shutdown)	Minimum time to loss of shutdown margin, minutes	15	15.32
	(cold shutdown)	Minimum time to loss of shutdown margin, minutes	15	15.69–filled loop 16.65–drained loop
	(during refueling)	Minimum time to loss of shutdown margin, minutes	30	37.14

TABLE 6.3.1-1 (continued)
NON-LOCA ANALYSIS LIMITS AND SELECTED ANALYSIS RESULTS

UFSAR Section	Event Description	Result Parameter	Selected Result	
			Analysis Limit	(Limiting Case)
15.4.8	Spectrum of Rod Cluster Control Assembly Ejection Accidents			
	(Beginning of life hot zero power)	Maximum fuel pellet average enthalpy, Btu/lb	360	253.2
		Maximum fuel melt, %	10	0.0
	(Beginning of life hot full power)	Maximum fuel pellet average enthalpy, Btu/lb	360	294.7
		Maximum fuel melt, %	10	0.31
	(End of life hot zero power)	Maximum fuel pellet average enthalpy, Btu/lb	360	268.9
		Maximum fuel melt, %	10	0.0
	(End of life hot full power)	Maximum fuel pellet average enthalpy, Btu/lb	360	294.8
		Maximum fuel melt, %	10	1.79
15.5.1 and 15.5.2	Inadvertent Operation of Emergency Core Cooling System during Power Operation	Pressurizer Filling Time	Operator action at 10 minutes to preclude filling	
	CVCS Malfunction that Increases Reactor Coolant Inventory	Pressurizer Filling Time	Operator action at 10 minutes to preclude filling	
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	Minimum departure from nucleate boiling ratio	1.47	1.87
15.8	Anticipated Transient Without Scram	Maximum ASME Boiler and Vessel Code Level C service limit stress, psia	3215	3211.89

Table 6.3.1-2
Non-LOCA Plant Initial Condition Assumptions for the SPU

Nominal Conditions	
Analyzed NSSS Power (MWt)	3678 MWt
Analyzed Reactor Core Power (MWt)	3659 MWt
NSSS Thermal Design Flow (per loop)	93,600 gpm
Minimum Measured Flow (per loop)	95,950 gpm
Core Bypass Flow Fraction (non-statistical) (statistical)	8.3% 6.8%
Programmed Full-Power Reactor Coolant System Average Temperature	589.1°F maximum 571.0°F minimum
No-Load Reactor Coolant System Temperature	557.0°F
Feedwater Temperature	390.0°F and 452.4°F
Steam Generator Design	Westinghouse Model F
Maximum steam generator tube plugging level	10% average/peak
Departure from nucleate boiling methodology (where applicable)	Revised Thermal Design Procedure
Safety Analysis Limit departure from nucleate boiling ratio	1.47 (typical & thimble cell)
Max F_{DH} (non-statistical) (statistical)	1.650 1.587
Max F_Q	2.50
Rod Average Thermal Output	5.840 kW/ft
Pressurizer Water Level (% span)	60% High T_{avg} 33.1% Low T_{avg} 25% No Load
Steam Generator Water Level (% narrow range span)	50%
Initial Condition Uncertainties[1]: Power Temperature Pressure Steam generator water level Pressurizer water level	 ± 0% Rated Thermal Power ± 3.0°F, -3.0°F bias ± 50 psi +14.5% narrow range span / -8.0% narrow range span ± 5 % span

Notes:

1. A negative uncertainty / bias means that the instrument indicates low and that the actual condition is greater than indicated.
2. A full-power Reactor Coolant System T_{avg} window between 571.0°F and 589.1°F is supported. Some analyses only use one full-power T_{avg} value either because a clear direction of conservatism exists, or because the full-power T_{avg} does not have a significant effect on the analysis results.
3. The analyses assume a programmed no-load Reactor Coolant System T_{avg} of 557°F. For the events initiated from a no-load condition [rod withdrawal from subcritical, steam line break, rod ejection, boron dilution], the use of the no-load temperature as the initial temperature bounds the case of startup operations at Seabrook being performed at a hot-zero power temperature lower than 557°F. This is because the departure from nucleate boiling ratio calculations and the boron dilution calculations would be less limiting at a lower Reactor Coolant System temperature.
4. The nominal pressurizer water level varies linearly from 25% of span at an Reactor Coolant System T_{avg} of 557°F to 33.1% of span at an Reactor Coolant System T_{avg} of 571.0°F for Reactor Coolant System full-power T_{avg} less than or equal to 571.0°F. For an Reactor Coolant System full-power T_{avg} of 589.1°F, the nominal pressurizer water level varies linearly from 25% of span at an Reactor Coolant System T_{avg} of 557°F to 60% of span at the Reactor Coolant System T_{avg} of 589.1°F.
5. The nominal steam generator water level modeled in the analyses performed in support of the SPU is a constant 50% narrow range span, regardless of the power level.

TABLE 6.3.1-3
SUMMARY OF REACTOR PROTECTION SYSTEM AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM FUNCTIONS ACTUATED

USAR Section	Event Description	Reactor Protection System Or Engineered Safety Feature Actuation System Signal(s) Actuated	Analysis Setpoint	Delay (sec)
15.1.1	Feedwater Temperature Reduction Incident	N/A	N/A	N/A
15.1.2	Excessive Heat Removal Due to Feedwater System Malfunctions (Feedwater Flow Increase)	Hi-Hi steam generator water level turbine trip with reactor trip on turbine trip	100% narrow range span	2.0 and 2.0, respectively
15.1.3	Excessive Load Increase Incident	N/A	N/A	N/A
15.1.5	Steam Line Break	Lo-Lo steam pressure Safety Injection setpoint	430 psia	2.0
		Steamline isolation delay	N/A	6.0
		Feedwater isolation delay	N/A	12.0
		Safety Injection pumps at full flow following Safety Injection signal	N/A	27.0 (w/ offsite power)
15.2.2 and 15.2.3	Loss of External Load / Turbine Trip	High pressurizer pressure reactor trip	2425 psia	2.0
		Overtemperature ΔT reactor trip	LAR Figure 6.3.3.1-2	Note 1
15.2.6	Loss of All AC Power to the Station Auxiliaries	Lo-Lo steam generator water level reactor trip	0% narrow range span	2.0
		Lo-Lo steam generator water level emergency feedwater pump start	0% narrow range span	77.0
15.2.7	Loss of Normal Feedwater	Lo-Lo steam generator water level reactor trip	0% narrow range span	2.0
		Lo-Lo steam generator water level emergency feedwater pump start	0% narrow range span	77.0
15.2.8	Feedwater System Pipe Break	Lo-Lo steam generator water level reactor trip	0% narrow range span	2.0
		Lo-Lo steam generator water level emergency feedwater pump start	0% narrow range span	100.0

TABLE 6.3.1-3 (continued)
SUMMARY OF REACTOR PROTECTION SYSTEM AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM FUNCTIONS ACTUATED

USAR Section	Event Description	Reactor Protection System Or Engineered Safety Feature Actuation System Signal(s) Actuated	Analysis Setpoint	Delay (sec)
15.3.1 and 15.3.2	Loss of Reactor Coolant Flow	Low Reactor Coolant System loop flow reactor trip	87%	1.0
15.3.3-15.3.4	Locked Rotor	Low Reactor Coolant System loop flow reactor trip	87%	1.0
15.4.1	Uncontrolled Rod Control Cluster Assembly Withdrawal from a Subcritical Condition	Power-range high neutron flux reactor trip (low setting)	35%	0.5
15.4.2	Uncontrolled Rod Control Cluster Assembly Withdrawal at Power	Power-range high neutron flux reactor trip (high setting)	118%	0.5
		Overtemperature ΔT reactor trip	LAR Figure 6.3.5.2-2	Note 1
15.4.3	Rod Control Cluster Assembly Misalignment	Low pressurizer pressure reactor trip	Note 2	2.0
15.4.4	Startup of an Inactive Reactor Coolant Loop	N/A	N/A	N/A
15.4.6	Chemical and Volume Control System Malfunction	Overtemperature ΔT reactor trip	LAR Figure 6.3.5.2-2	Note 1
15.4.8	Spectrum of Rod Cluster Control Assembly Ejection Accidents	Power-range high neutron flux reactor trip (low and high settings)	35% (low setting)	0.5
			118% (high setting)	0.5
15.5.1	Inadvertent Operation of Emergency Core Cooling Systems during Power Operation	N/A	N/A	N/A
15.5.2	Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	N/A	N/A	N/A
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	Low pressurizer pressure reactor trip	1935 psia	2.0
15.8	Anticipated Transient Without Scram	N/A	N/A	N/A

TABLE 6.3.1-3 (continued)
SUMMARY OF REACTOR PROTECTION SYSTEM AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM FUNCTIONS ACTUATED

Note 1:	The modeling of the overtemperature ΔT reactor trip includes a time constant (first order lag) of 4.0 seconds for the measurement of the vessel T_{avg} and ΔT. This lag accounts for the response of the resistance temperature detectors and the resistance temperature detector electronic filter (if any). In addition, a straight delay of 2.0 seconds is assumed which accounts for electronics delay, reactor trip breakers opening, and rod control cluster assembly gripper release.
Note 2:	The generic four-loop dropped rod control cluster assembly analysis, applicable to Seabrook Station, models the low pressurizer pressure reactor trip setpoint as a convenience trip. The cases that actuate this function assume dropped rod and control bank worth combinations that are non-limiting with respect to departure from nucleate boiling. The use of a plant-specific low pressurizer pressure setpoint that is lower than the value assumed in the generic analysis does not invalidate the generic four-loop statepoints evaluated as part of the Seabrook SPU Program. Therefore, the low pressurizer pressure reactor trip setpoint value that is used in the generic four-loop dropped rod control cluster assembly analysis (1935 psia) does not represent an analytical limit for this function for Seabrook Station.

TABLE 6.3.1-4
SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Accident	Computer Codes Used	Departure from Nucleate Boiling Correlation	Revised Thermal Design Procedure	Initial Power, %	Reactor Coolant Flow, gpm	Vessel Average Coolant Temp, °F	Reactor Coolant System Pressure, psia
Feedwater Temperature Reduction Incident	Bounded by Excessive Load Increase						
Excessive Heat Removal Due to Feedwater System Malfunctions (Feedwater Flow Increase)	RETRAN VIPRE	WRB-2M (hot full power) W-3 (hot zero power)	Yes No	100 0 (3678 MWt - NSSS power)	383,800 374,400	589.1 557.0	2,250
Excessive Load Increase Incident	N/A	WRB-2M	Yes	100 (3659 MWt - core power)	383,800	589.1	2,250
Steam Line Break	RETRAN VIPRE	W-3	No	0 (3678 MWt - NSSS power)	374,400	557.0	2,250
Loss of External Electrical Load	RETRAN	WRB-2M	No (Overpressure) Yes (Departure from nucleate boiling)	100 (pressure) 100 (DNB) (3678 MWt - NSSS power)	374,400 (pressure) 383,800 (Departure from nucleate boiling)	595.1 (pressure) 589.1 (DNB)	2,200 (pressure) 2,250 (Departure from nucleate boiling)
Loss of Normal Feedwater/Loss of AC Power to the Plant Auxiliaries	RETRAN	N/A	No	100 (3678 MWt - NSSS power)	374,400	595.1 584.1 (Note 1) 577.0 (Note 2) 566.0	2,300 2,200
Feedwater System Pipe Break	RETRAN	WRB-2M	No	100 (3678 MWt NSSS power)	374,400	595.1	2,200

TABLE 6.3.1-4 (continued)
SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Accident	Computer Codes Used	Departure from Nucleate Boiling Correlation	Revised Thermal Design Procedure	Initial Power, %	Reactor Coolant Flow, gpm	Vessel Average Coolant Temp, °F	Reactor Coolant System Pressure, psia
Loss of Reactor Coolant Flow	RETRAN VIPRE	WRB-2M	Yes	100 (3678 MWt - NSSS power)	383,800	589.1	2,250
Locked Rotor	RETRAN VIPRE	WRB-2M	No (Hot Spot) Yes (Departure from nucleate boiling)	100 (hot spot) 100 (DNB) (3678 MWt - NSSS power)	374,400 (hot spot) 383,800 (Departure from nucleate boiling)	595.1 (hot spot) 589.1 (DNB)	2,300 (hot spot) 2,250 (Departure from nucleate boiling)
Uncontrolled RCCA Withdrawal from a Subcritical Condition	TWINKLE FACTRAN VIPRE	W-3[1] WRB-2[2]	No	0 (3659 MWt – core power)	166,533	557	2,200
Uncontrolled RCCA Withdrawal at Power	RETRAN	WRB-2M	Yes (Departure from nucleate boiling)	100 (Departure from nucleate boiling) 60 (Departure from nucleate boiling) 10 (Departure from nucleate boiling)	383,800 ((Departure from nucleate boiling)	589.1 (100%) 576.3 (60%) 560.2 (10%)	2,250 (Departure from nucleate boiling)
RCCA Misalignment	LOFTRAN VIPRE	WRB-2M	Yes	100	383,800	589.1	2,250
Startup of an Inactive Reactor Coolant Loop	Seabrook Technical Specifications prevent event occurrence						
Chemical and Volume Control System Malfunction	N/A	N/A	N/A	N/A	N/A	N/A	N/A

TABLE 6.3.1-4 (continued)
SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Accident	Computer Codes Used	Departure from Nucleate Boiling Correlation	Revised Thermal Design Procedure	Initial Power, %	Reactor Coolant Flow, gpm	Vessel Average Coolant Temp, °F	Reactor Coolant System Pressure, psia
Rupture of a Control Rod Drive Mechanism Housing – Rod Control Cluster Assembly Ejection	TWINKLE FACTRAN	N/A	No	100 (hot full power) 0 (hot zero power) (3659 MWt - core power)	374,400 (hot full power) 166,533 (hot zero power)	595.1 (hot full power) 557.0 (hot zero power)	2,200
Inadvertent Operation of Emergency Core Cooling System during Power Operation	RETRAN	WRB-2M	No	100 (3678 MWt NSSS power)	374,400	584.1(Note 1)	2,200
Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	RETRAN	WRB-2M	No	100 (3678 MWt NSSS power)	374,400	584.1(Note 1)	2,200
Inadvertent Opening of a Pressurizer Safety or Relief Valve	RETRAN	WRB-2M	Yes	100 (3678 MWt NSSS power)	383,800	589.1	2,250
ATWS	LOFTRAN	WRB-2M	Yes	100 (3678 MWt NSSS power)	374,400	589.1	2,250

NOTES:

1. T_{avg} = 584.1°F provides the most conservative results based on sensitivities performed with the analysis.
2. T_{avg} = 577.0°F provides the most conservative results based on sensitivities performed with the analysis.

TABLE 6.3.1-5
CORE KINETICS PARAMETERS AND REACTIVITY FEEDBACK COEFFICIENTS

Parameter	Beginning of Life (Min. Feedback)	End of Life (Max. Feedback)
Moderator Temperature Coefficient, pcm/°F	5.0 (below 70% Rated Thermal Power)	N/A
	0.0 (at 100% Rated Thermal Power, linear ramp from 100% to 70%)	N/A
Moderator Density Coefficient, Δk/(g/cc)	N/A	0.54
Doppler Temperature Coefficient, pcm/°F	-0.90	-3.20
Doppler-Only Power Coefficient, pcm/% power (Q = power in %)	-9.55 + 0.035Q	-19.40 + 0.068Q
Delayed Neutron Fraction	0.0075 (maximum)	0.0044 (minimum)
Minimum Shutdown Margin, %Δk	1.30	1.30
Minimum Doppler Power Defect, pcm		
Rod Ejection	900	900
Rod Withdrawal from Subcritical	900	NA

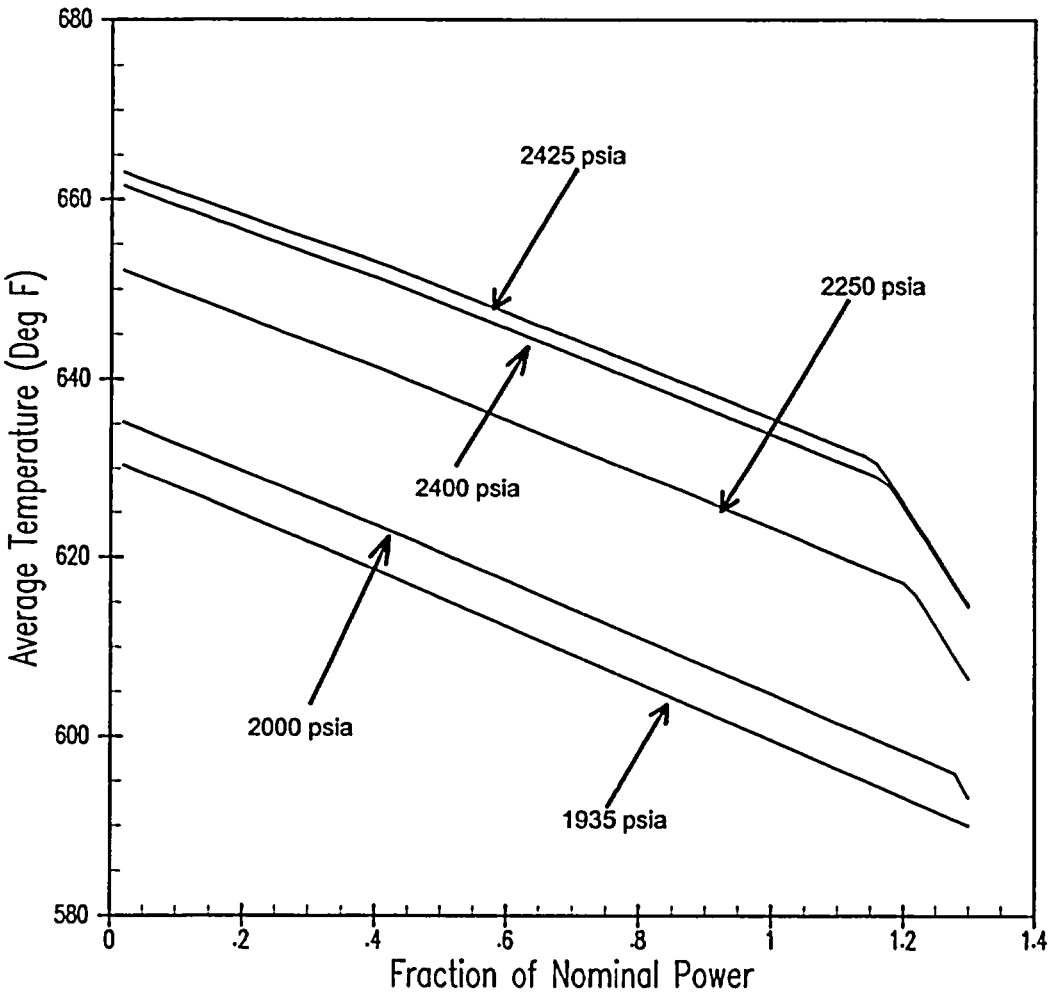


Figure 6.3.1-1
Reactor Core Safety Limit

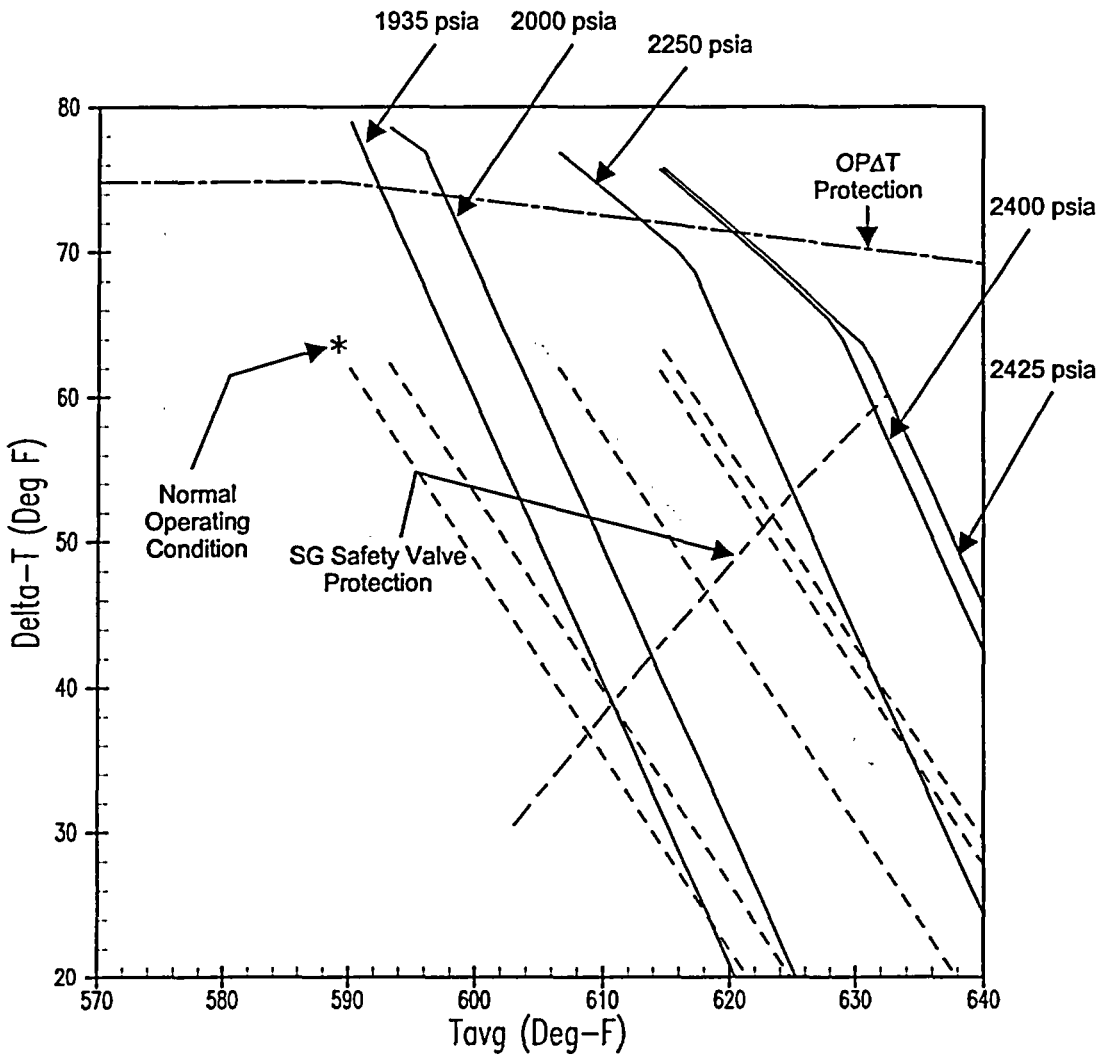


Figure 6.3.1-2
Illustration of Overtemperature and Overpower ΔT Protection

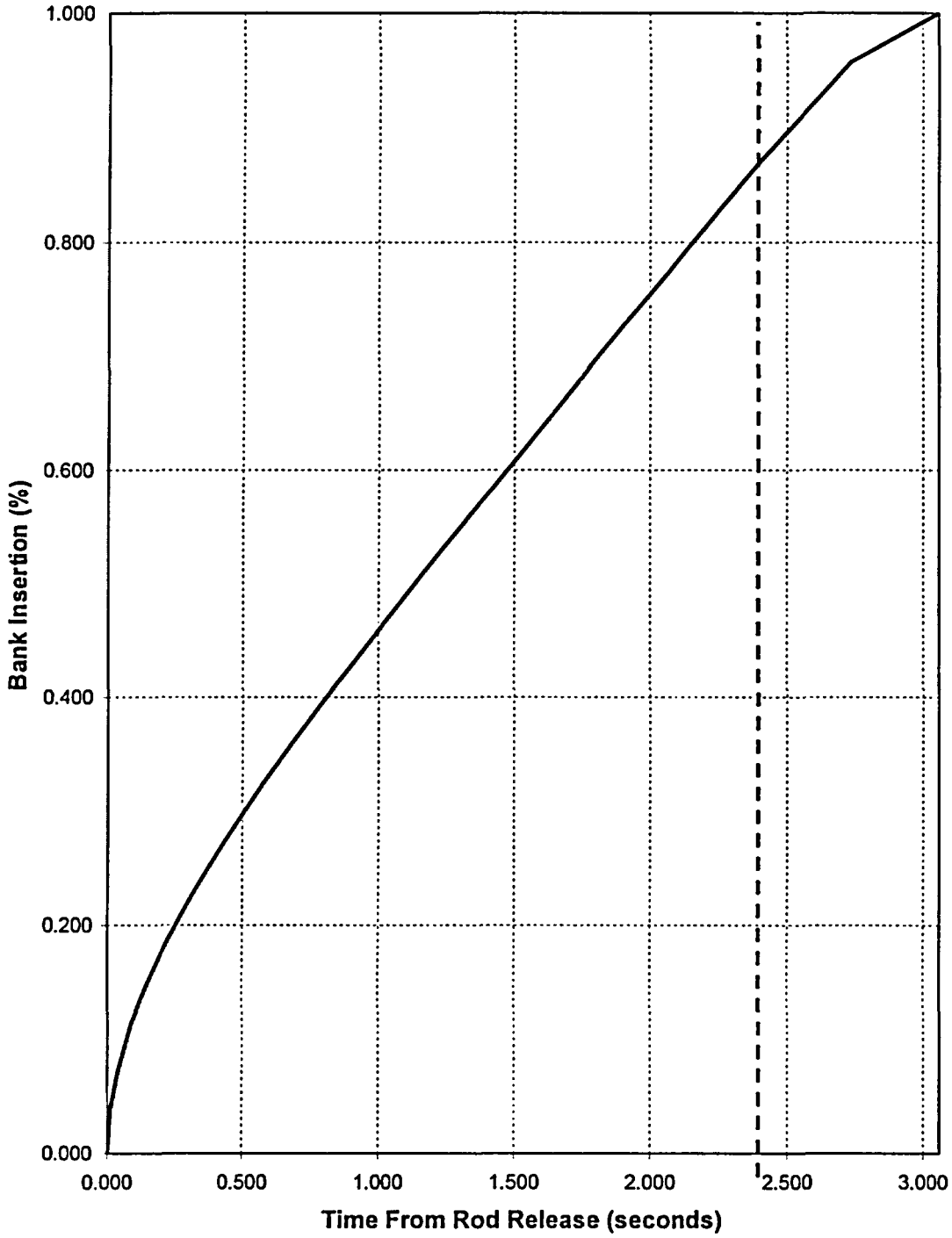


Figure 6.3.1-3
Rod Control Cluster Assembly Position (Insertion) versus Time From Release

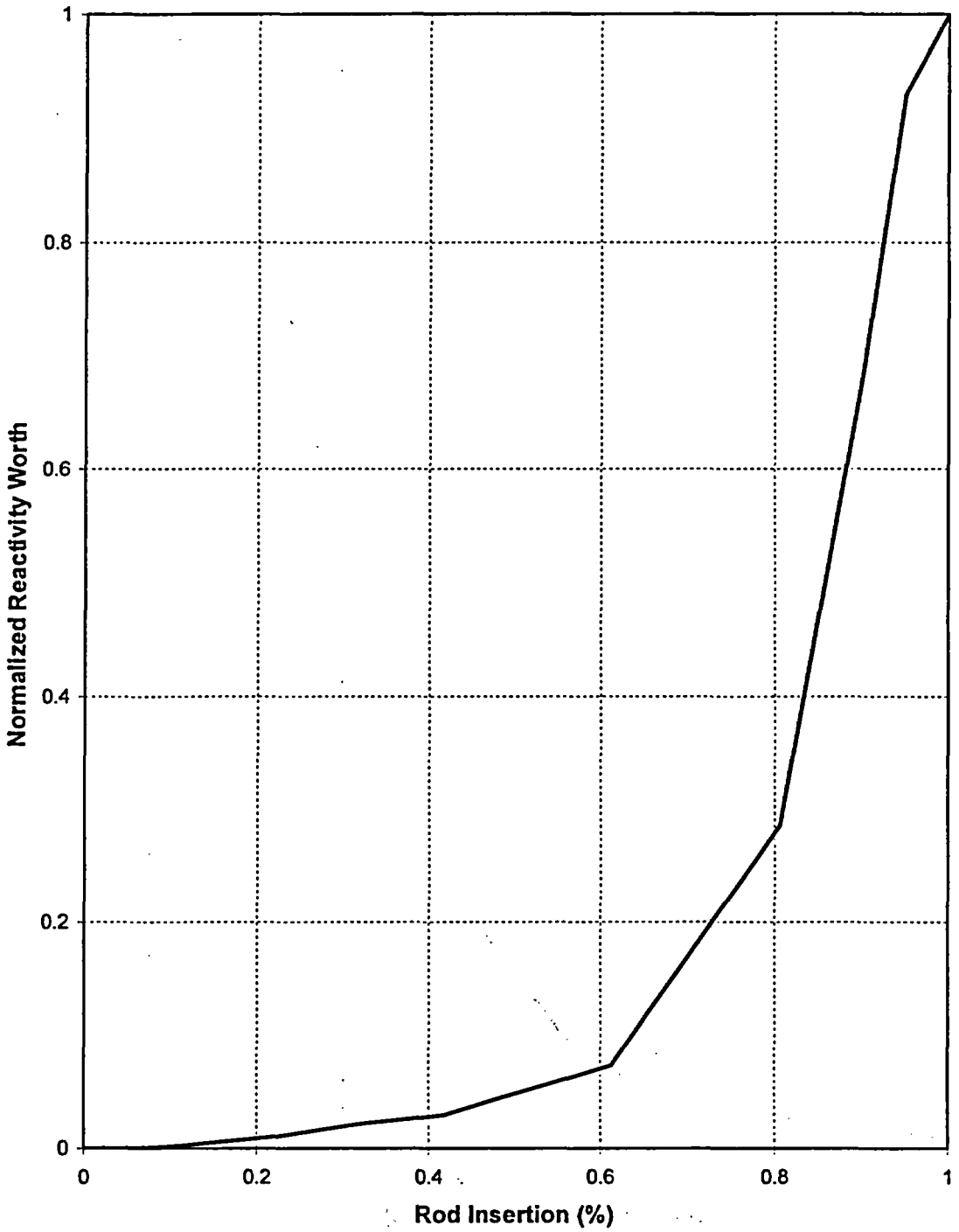


Figure 6.3.1-4
Normalized Rod Control Cluster Assembly Reactivity Worth versus Percent Insertion

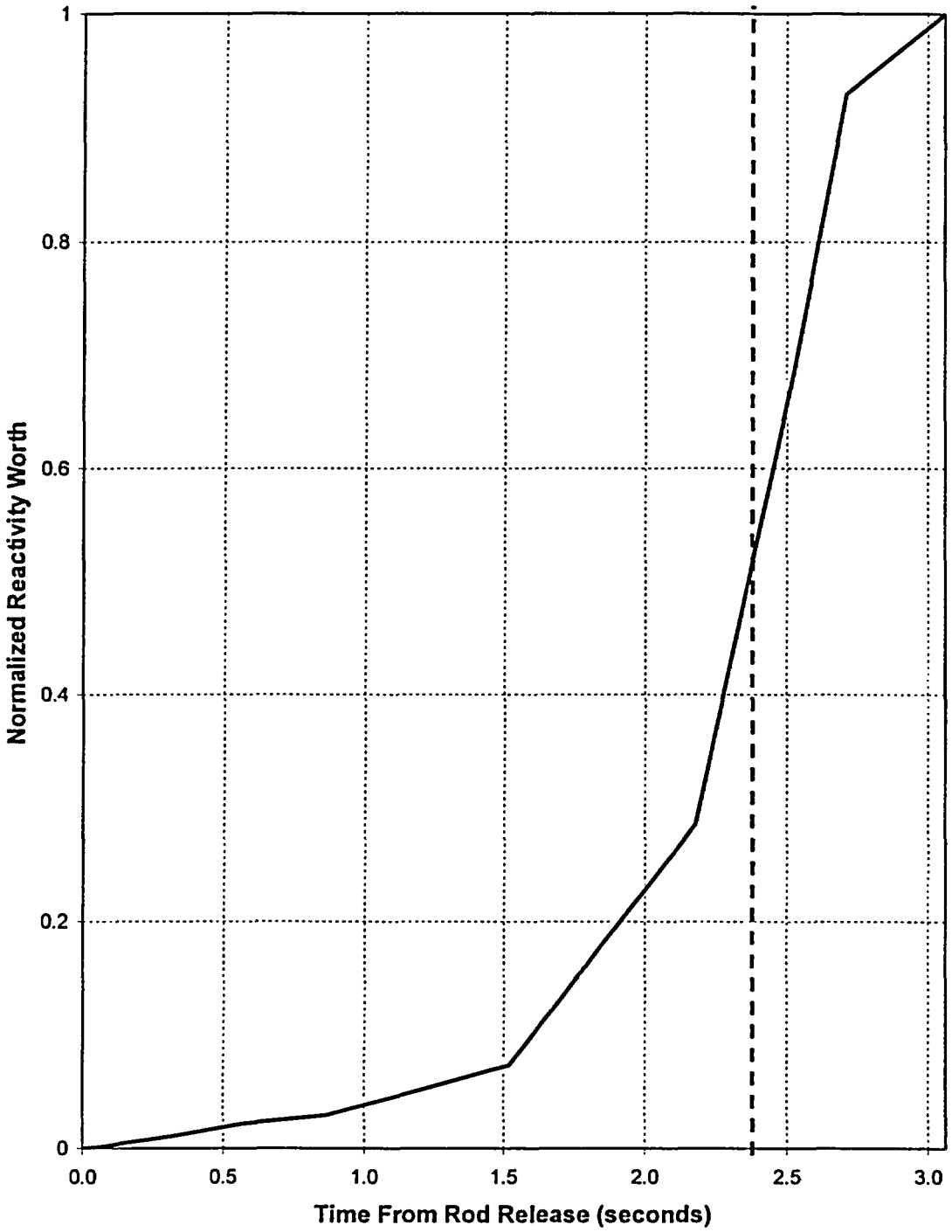


Figure 6.3.1-5
Normalized Rod Control Cluster Assembly Bank Reactivity Worth versus Time

6.3.2 INCREASE IN HEAT REMOVAL

6.3.2.1 EXCESSIVE HEAT REMOVAL DUE TO FEEDWATER SYSTEM MALFUNCTIONS (SEABROOK STATION UFSAR SECTIONS 15.1.1 AND 15.1.2)

A change in steam generator feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the Reactor Coolant System. Such changes in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve or feedwater bypass valve, failure in the feedwater control system, or operator error.

The occurrence of these failures that result in excessive heat removal from the Reactor Coolant System cause the primary-side temperature and pressure to decrease significantly. The existence of a negative moderator and fuel temperature reactivity coefficients, and the actions initiated by the reactor rod control system can cause core reactivity to rise, as the primary-side temperature decreases. In the absence of the Reactor Protection System reactor trip or other protective action, this increase in core power, coupled with the decrease in primary-side pressure, can challenge the core thermal limits.

6.3.2.1.1 ACCIDENT DESCRIPTION

Feedwater Temperature Reduction

Reductions in feedwater temperature will cause an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the Reactor Coolant System. The overpower - overtemperature protection (neutron overpower, overtemperature ΔT and overpower ΔT trips) prevents a power increase which could lead to a Departure from Nucleate Boiling Ratio less than the safety analysis limit value. A reduction in feedwater temperature may be caused by the accidental opening of a feedwater bypass valve which diverts flow around a portion of the feedwater heaters. In the event of an accidental opening of a bypass valve, there is a sudden reduction in feedwater inlet temperature to the steam generators. At power, this increased subcooling will create a greater load demand on the Reactor Coolant System.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in Reactor Coolant System temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flow decrease, so the no-load transient is less severe than the full power case. The net effect on the Reactor Coolant System due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow, i.e., the reactor will reach a new equilibrium condition at a power level corresponding to the new steam generator ΔT. A decrease in normal feedwater temperature is classified as an American Nuclear Society Condition II event, a fault of moderate frequency.

Feedwater Flow Increase

Additions of excessive feedwater will cause an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the Reactor Coolant System. The overpower-overtemperature protection (neutron overpower, overtemperature ΔT and overpower ΔT trips) prevent a power increase which could lead to a Departure from Nucleate Boiling Ratio less than the safety analysis limit value. An example of excessive feedwater flow would be a full opening of a 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 Reactor Coolant System due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of an excess of feedwater may cause a decrease in Reactor Coolant System temperature and thus a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. Continuous addition of excessive feedwater is prevented by the steam generator high-high level trip, which activates the feedwater isolation. Pre-trip alarm of high steam generator level is available in the control room. An increase in normal feedwater flow is classified as an American Nuclear Society Condition II event, a fault of moderate frequency.

6.3.2.1.2 METHOD OF ANALYSIS

Feedwater Temperature Reduction

This transient is analyzed by computing conditions at the feedwater pump inlet following opening of the heater bypass valve. These feedwater conditions are used to recalculate a heat balance through the high pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet. The following assumptions are made:

1. Plant initial power level corresponding to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).
2. Low pressure heater bypass valve opens, resulting in condensate flow splitting between the bypass line and the low pressure heaters; the flow through each path is proportional to the pressure drops.
3. Heater drain pumps trip; this increases the effect of the cold bypass flow.

An evaluation method was applied that demonstrates the decreased enthalpy caused by the feedwater temperature reduction is bounded by an equivalent enthalpy reduction that results from a steam system piping failure initiated from full power conditions (Seabrook Station UFSAR Section 15.1.5). No explicit analysis is performed. The steam system piping failure is a American Nuclear Society Condition IV event, however, it is analyzed to American Nuclear Society Condition II acceptance criteria.

Feedwater Flow Increase

The feedwater system malfunction transient is analyzed using the RETRAN code. The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code, which has been reviewed and approved by the Nuclear Regulatory Commission for

pressurized water reactor licensing applications [Reference 6.3-1]. The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, and two-phase natural convection heat transfer correlations. The results from the RETRAN computer code are used to determine whether the departure from nucleate boiling safety analysis limits for the excessive heat removal due to feedwater malfunction event are met.

Three cases are analyzed as follows:

1. Accidental opening of one feedwater control valve with the reactor in automatic control at full power.
2. Accidental opening of one feedwater control valve with the reactor in manual control at full power.
3. Accidental opening of one feedwater control valve with the reactor at zero load, with the reactor just critical.

This accident is analyzed with the Revised Thermal Design Procedure as described in WCAP-11397 [Reference 6.3-8]. The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

1. For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 187 percent of nominal feedwater flow to one steam generator.
2. For the feedwater control valve accident at zero load condition, a feedwater control valve malfunction occurs which results in an increase in flow to one steam generator from zero to 200 percent of the nominal full load value for one steam generator.
3. For the full load condition, the feedwater temperature is at 390°F. For the zero load condition, the feedwater temperature is at a conservatively low value of 100°F.
4. No credit is taken for the heat capacity of the Reactor Coolant System and steam generator thick metal in attenuating the resulting plant cooldown.
5. The feedwater flow resulting from a fully-open control valve is terminated by a steam generator high-high level trip signal which closes all feedwater control and isolation valves, trips the main feedwater pumps, and trips the turbine.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system may function to trip the reactor due to overpower or high-high steam generator water level conditions. No single active failure will prevent operation of the reactor protection system.

6.3.2.1.3 RESULTS

Feedwater Temperature Reduction

The opening of a low-pressure heater bypass valve causes a reduction in feedwater temperature which increases the thermal load on the primary system. The reduction in feedwater temperature is less than 35°F, resulting in an increase in heat load on the

primary system of less than 10 percent of full power. The reduction in feedwater temperature due to a 10-percent step load increase is greater than 35°F. The increased thermal load, due to the opening of the low-pressure heater bypass valve, thus results in a transient very similar, but of reduced magnitude, to the steam system piping failure initiated from full power conditions described in LAR Section 6.3.2.4. No transient results are presented, as no explicit analysis is performed.

Feedwater Flow Increase

The calculated sequences of events for the full power and zero power cases are shown in LAR Tables 6.3.2.1-1 and 6.3.2.1-2, respectively. The full power cases with maximum reactivity feedback coefficients give the largest reactivity feedback and result in the highest peak power. The manual and automatic rod control cases give similar results (although the manual control case has a slightly higher peak power and a slightly lower minimum departure from nucleate boiling ratio value). The rod control system is not required to function for an excessive feedwater flow event. When the steam generator water level in the faulted loop reaches the high-high level setpoint, all feedwater control valves and feedwater isolation valves are automatically closed and the main feedwater pumps are tripped. In addition, a turbine trip is initiated.

Transient results for the full power and zero power cases are provided in LAR Figures 6.3.2.1-1 through 6.3.2.1-4. The departure from nucleate boiling ratio does not fall below the limit value. Following reactor trip (full power cases), the plant approaches a stabilized condition. Since the power level rises during the excessive feedwater flow incident, the fuel temperatures will also rise until after reactor trip occurs. The core heat flux lags behind the neutron flux response due to the fuel rod thermal time constant, hence the peak value does not exceed 118 percent of its nominal value (i.e., the assumed high neutron flux trip setpoint). The peak fuel temperature will thus remain well below the fuel melting temperature.

6.3.2.1.4 CONCLUSIONS

Feedwater system malfunction transients involving a reduction in feedwater temperature or an increase in feedwater flow rate have been analyzed or evaluated. These transients show an increase in reactor power due to the excessive heat removal in the steam generators. With respect to the feedwater temperature reduction transient (accidental opening of the feedwater bypass valve), it was determined to be less severe than the steam system piping failure initiated at full power conditions (see Seabrook Station UFSAR Section 15.1.5); no explicit analysis is performed. Based on the summary of results presented in LAR Section 6.3.2.1.3, the applicable acceptance criteria for the feedwater temperature reduction transient have been met. Analyses of the accidental opening of the feedwater regulating valve were performed from a full-power initial condition with and without automatic rod control, and from a zero-power initial condition. It has been demonstrated that considerable margin to the safety analysis acceptance criteria exists throughout the transient. Therefore, the departure from nucleate boiling design basis is satisfied. Hence, no fuel damage is predicted.

6.3.2.2 EXCESSIVE INCREASE IN SECONDARY STEAM FLOW (SEABROOK STATION UFSAR SECTION 15.1.3)

6.3.2.2.1 ACCIDENT DESCRIPTION

An excessive load increase incident is defined as an event resulting in a rapid increase in the steam generator steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10-percent step load increase or a 5-percent per minute ramp load increase (without a reactor trip) in the range of 15 to 100 percent of full power. A loading rate in excess of these values may cause a reactor trip actuated by the Reactor Protection System.

This incident 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.

During power operation, steam dump to the condenser is controlled by comparing the reactor coolant system temperature (median T_{avg}) to a reference temperature based on turbine power, where a high difference in conjunction with a loss of load or a turbine trip indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided that blocks the opening of the valves unless a large turbine load decrease or turbine trip has occurred. In addition, the reference temperature and loss of load signals are developed by independent sensors.

Protection against an excessive load increase incident is provided by the following Reactor Protection System signals:

- Overpower ΔT
- Overtemperature ΔT
- Power range high neutron flux
- Low pressurizer pressure

6.3.2.2.2 METHOD OF ANALYSIS

Four cases are considered to demonstrate that the fuel cladding integrity will not be adversely impacted following a 10-percent step-load increase from rated load. This is shown by demonstrating that the minimum departure from nucleate boiling ratio will not go below the safety analysis limit value.

- Manually-controlled reactor with beginning of life (minimum moderator) reactivity feedback
- Manually-controlled reactor with end of life (maximum moderator) reactivity feedback
- Automatically-controlled reactor with beginning of life (minimum moderator) reactivity feedback

- Automatically-controlled reactor with end of life (maximum moderator) reactivity feedback

At beginning of life minimum moderator feedback conditions, the core has the least-negative moderator temperature coefficient of reactivity and the least-negative Doppler only power coefficient curve, and therefore, the least-inherent transient response capability. Since a positive moderator temperature coefficient would provide a transient benefit, a zero moderator temperature coefficient was evaluated for the minimum feedback conditions. For the end of life maximum moderator feedback conditions, the moderator temperature coefficient of reactivity has its most-negative value and the most-negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

The effect of this transient on the minimum departure from nucleate boiling ratio is 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 in order to generate a limiting set of statepoints. These deviations bound the variations which could occur as a result of an excessive load increase incident and are only applied in the direction that has the most adverse impact on the departure from nucleate boiling ratio; namely increased power, increased coolant temperature, and decreased pressure. No credit is taken for the decrease in coolant temperature and no reactor trip is assumed.

The reactor condition statepoints (temperature, pressure, and power) are compared to the conditions corresponding to operation at the safety analysis departure from nucleate boiling limit.

Normal reactor control systems and engineered safety systems are not required to function. A conservative limit on the turbine valve opening is assumed. The analysis does not take credit for pressurizer heaters.

The Reactor Protection System is assumed to be operable. However, reactor trip is not encountered for most cases. No single active failure in a system or component required for mitigation will adversely affect the consequences of this incident.

This incident is evaluated with the Revised Thermal Design Procedure as described in WCAP-11397-P-A [Reference 6.3-8]. Initial reactor power, Reactor Coolant System pressure, and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit departure from nucleate boiling ratio as described in Reference 6.3-8.

6.3.2.2.3 RESULTS

An excessive load increase incident 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 departure from nucleate boiling limit indicate that the minimum departure from nucleate boiling ratio remains above the limit value for each of the cases.

6.3.2.2.4 CONCLUSIONS

It has been demonstrated that for an excessive load increase incident, the minimum departure from nucleate boiling ratio during the transient will remain above the safety analysis limit value and thus will neither affect fuel cladding integrity nor result in the release of fission products to the Reactor Coolant System.

6.3.2.3 INADVERTENT OPENING OF A STEAM GENERATOR DUMP, RELIEF, OR SAFETY VALVE (SEABROOK STATION UFSAR SECTION 15.1.4)

6.3.2.3.1 ACCIDENT DESCRIPTION

The most severe core conditions resulting from an accidental depressurization of the Main Steam System are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses performed assuming a rupture of a main steam line are given in LAR Section 6.3.2.4.

The steam release as a consequence of this accident results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the Reactor Coolant System causes a reduction in coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity and a reduction of core shutdown margin.

The analysis is performed to demonstrate that the following criterion is satisfied:

Assuming a stuck Rod Cluster Control Assembly, with offsite power available and assuming a single failure in the Engineered Safety Features System, there will be no consequential damage to the core or Reactor Coolant System after reactor trip for a steam release equivalent to the spurious opening, with failure to close of the largest single steam dump, relief, or safety valve.

Accidental depressurization of the secondary system is classified as an American Nuclear Society Condition II event. See LAR Section 6.3.1.8 for a discussion of Condition II events.

The following systems provide the necessary protection against an accidental depressurization of the Main Steam System.

- Safety injection system actuation from any of the following:
  - Two-out-of-four low pressurizer pressure signals
  - Two-out-of-three high-1 containment pressure signals
  - Two-out-of-three low steam line pressure signals in any one loop.
- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

- Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main feedwater valves following reactor trip, a safety injection signal will rapidly close all feedwater control valves and backup feedwater isolation valves and trip the main feedwater pumps.
- Trip of the fast-acting steam line stop valves (designed to close in less than 5 seconds) on:
  - High-2 containment pressure
  - Safety injection system actuation derived from two out of three low steam line pressure signals in any one loop (above Permissive P-11)
  - Two out of three high negative steam line pressure rate in any one loop (below Permissive P-11).

6.3.2.3.2 METHOD OF ANALYSIS

The consequences of an inadvertent opening of a steam generator dump, relief, or safety valve are bounded by the zero power steam line rupture discussed in LAR Section 6.3.2.4. The opening of a steam generator dump, relief, or safety valve causes a slower steam generator blowdown and Reactor Coolant System cooldown than the steam line rupture event. This would result in a lower power level if a return to power were to occur as predicted for the zero power steam line rupture. The minimum departure from nucleate boiling ratio for the zero power steam line rupture, which remains above the safety analysis limit, would be lower than that for the opening of a steam generator dump, relief, or safety valve.

6.3.2.3.3 RESULTS

Since the minimum departure from nucleate boiling ratio for the zero power steam line rupture (LAR Section 6.3.2.4) remains above the safety analysis limit, there would be no fuel failure predicted for an inadvertent opening of a steam generator dump, relief, or safety valve.

6.3.2.3.4 CONCLUSIONS

The analysis shows that the criteria stated earlier in this section are satisfied. The departure from nucleate boiling ratio in maintained above the safety analysis limit value.

6.3.2.4 STEAM SYSTEM PIPING FAILURE (SEABROOK STATION UFSAR SECTION 15.1.5)

6.3.2.4.1 ACCIDENT DESCRIPTION

A steam line break transient would result in an uncontrolled increase in steam flow release from the steam generators, with the flow decreasing as the steam pressure drops. This steam flow release increases the heat removal from the Reactor Coolant System, which decreases the Reactor Coolant System temperature and pressure. With the existence of a negative Moderator Temperature Coefficient, the Reactor Coolant System cooldown results in a positive reactivity insertion, and consequently a reduction

of the core shutdown margin. If the most reactive rod cluster control assembly is assumed stuck in its fully withdrawn position after reactor trip, the possibility is increased that the core will become critical and return to power. A return to power following a steam line break is a concern with the high-power peaking factors that may exist when the most reactive rod cluster control assembly is stuck in its fully withdrawn position. Following a steam line break, the core is ultimately shut down by the boric acid injected into the Reactor Coolant System by the Safety Injection System.

The steam line break analysis discussed herein was performed to demonstrate that there is no consequential damage to the primary system and that the core remains in place and intact. This analysis is known as the steam line break core response analysis. Although departure from nucleate boiling and fuel cladding damage are not necessarily unacceptable consequences of a steam line break transient, the analysis described herein demonstrates that there is no consequential damage to the primary system, and that the core remains in place and intact, by showing that the departure from nucleate boiling design basis is satisfied following a steam line break.

The systems and components that provide the necessary protection against a steam line break are listed as follows.

- Safety Injection System actuation by any of the following:
  - Two-out-of-four low pressurizer pressure signals
  - Two-out-of-three high-1 containment pressure signals
  - Two-out-of-three low steam line pressure signals in any one loop
- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring from the receipt of the safety injection signal.
- Redundant isolation of the main feedwater lines; sustained high feedwater flow would cause additional cooldown. In addition to normal control action that isolates main feedwater following a reactor trip, a safety injection signal will rapidly close all feedwater control valves and trip the main feedwater pumps.
- Closure of the main steam isolation valves. These valves are designed to close within five seconds after receipt of any of the following:
  - High-2 containment pressure
  - Safety Injection System actuation derived from two-out-of-three low steam line pressure signals in any one loop (above Permissive P-11)
  - Two-out-of-three high negative steam pressure rate signals in any one loop (below Permissive P-11)

For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For a 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.

Flow restrictors are installed in the steam generator outlet nozzle, an integral part of the steam generator. The effective throat area of the nozzles is 1.4 square feet, which is considerably less than the main steam pipe area; thus, the nozzles also serve to limit the maximum steam flow for a break at any location. Also, the main steam isolation valve seat area limits the reverse blowdown from the intact steam generators.

6.3.2.4.2 METHOD OF ANALYSIS

The steam line break transient is classified as an American Nuclear Society Condition IV event, but the analysis of the steam line break transient has been conservatively performed to demonstrate that the departure from nucleate boiling design basis is satisfied. This is accomplished by showing that the calculated minimum departure from nucleate boiling ratio is greater than the safety analysis limit departure from nucleate boiling ratio of 1.50 (W-3 low pressure departure from nucleate boiling correlation limit). The overall analysis process is described as follows.

Using the RETRAN code [Reference 6.3-1], transient values of key plant parameters identified as statepoints (core average heat flux, core pressure, core inlet temperature, Reactor Coolant System flow rate, and core boron concentration) were calculated first. Next, the Advanced Nodal Code core design code [Reference 6.3-12] was used to:

- Evaluate the nuclear response to the Reactor Coolant System cooldown so as to justify the RETRAN transient prediction of the average core power/reactivity
- Determine the peaking factors associated with the return to power in the region of the stuck rod control cluster assembly

Finally, using the RETRAN-calculated statepoints and the advanced nodal code calculated peaking factors, the detailed thermal and hydraulic computer code VIPRE [Reference 6.3-4] was used to calculate the minimum departure from nucleate boiling ratio based on the W-3 departure from nucleate boiling correlation.

The following assumptions were made in the analysis of the main steam line break:

1. A hypothetical double-ended rupture of a main steam line was postulated at hot zero power/hot shutdown conditions. The maximum break size is effectively limited to the flow area of the steam generator outlet nozzle flow restrictors (1.4 ft^2 per steam generator). The assumed conditions correspond to a subcritical reactor, an initial vessel average temperature at the no-load value of 557°F, and no core decay heat. These conditions are conservative for a steam line break transient because the resultant Reactor Coolant System cooldown does not have to remove latent heat. Also, the steam generator water inventory is greatest at no-load conditions, which increases the capability for cooling the Reactor Coolant System.
2. Perfect moisture separation within the steam generators was conservatively assumed.
3. An end-of-life shutdown reactivity margin of 1.3-percent $\Delta k/k$ corresponding to no-load, equilibrium xenon conditions, with the most reactive rod control cluster assembly stuck in its fully withdrawn position was assumed. The stuck rod control cluster assembly was assumed to be in the core location exposed to the greatest

cooldown; that is, related to the faulted loop. The reactivity feedback model included a positive moderator density coefficient corresponding to an end-of-life rodded core with the most reactive rod control cluster assembly in its fully withdrawn position.

The power predicted by RETRAN was compared to that predicted by the advanced nodal code core design code. The advanced nodal code core analysis considered the following:

- Doppler reactivity feedback from the high fuel temperature near the stuck rod control cluster assembly
- Moderator feedback from the high water enthalpy near the stuck rod control cluster assembly
- Power redistribution effects
- Non-uniform core inlet temperature effects

The advanced nodal code core analysis confirmed that the RETRAN-predicted power is acceptable.

4. Assuming no frictional losses, the Moody critical flow curve was applied to conservatively maximize the break flow rate.
5. The closure of the main steam isolation valves were conservatively modeled to be complete at 6.0 seconds after receipt of a safety injection signal due to a low steam line pressure (435 psia) signal.
6. The safety injection pumps were assumed to provide flow to the Reactor Coolant System at 27 seconds after receipt of a safety injection signal. This delay accounts for signal processing and pump startup delays, and, as applicable, diesel generator startup time.
7. The minimum capability for the injection of highly concentrated boric acid solution, corresponding to the most restrictive single active failure in the Safety Injection System, was assumed. The assumed safety injection flow solution from the refueling water storage tank, with a minimum concentration of 2400 ppm and a minimum temperature of 50°F, was the assumed source of the safety injection flow. The safety injection lines downstream of the refueling water storage tank were assumed to initially contain unborated water to conservatively maximize the time it takes to deliver the highly concentrated refueling water storage tank boric acid solution to the reactor coolant loops.
8. The safety injection accumulator tanks (one per loop) provide a passive injection of borated water into the Reactor Coolant System. The accumulators were assumed to have a minimum boron concentration of 2300 ppm, a minimum temperature of 37°F, and an initial gas pressure of 600 psia.
9. Main feedwater flow equal to the nominal (100-percent power) value was assumed to initiate coincident with the postulated break, and was maintained until feedwater isolation occurs. The feedwater isolation was conservatively assumed to be

complete at 12.0 seconds after the steam line pressure in the faulted loop reaches the low setpoint value that generates the safety injection signal.

10. A minimum steam generator tube plugging level of 0 percent was assumed to maximize the cooldown of the Reactor Coolant System.

11. Maximum (2295 gpm, 319.12 lbm/second) emergency feedwater to the faulted steam generator at a minimum temperature of 50°F was assumed to initiate coincident with the postulated break to maximize the cooldown of the Reactor Coolant System.

The following cases have been considered in determining the core power and Reactor Coolant System transients:

1. Complete severance of a pipe, with the plant initially at no-load conditions, full reactor coolant flow with offsite power available

2. Case 1 with a loss of offsite power resulting in a reactor coolant pump coastdown.

The limiting steam line break with return to power corresponds to the case with offsite power available. The offsite power available case results in the greatest challenge to departure from nucleate boiling.

6.3.2.4.3 RESULTS

The results of the statepoint evaluation demonstrate that the applicable departure from nucleate boiling ratio acceptance criterion is met. The time sequence of events and a summary of the departure from nucleate boiling ratio results are presented in LAR Table 6.3.2.4-1. LAR Figures 6.3.2.4-1 through 6.3.2.4-11 show the transient results following a double-ended rupture of a main steam line at initial no-load conditions with offsite power available (full reactor coolant flow). The effective break size was limited to 1.4 ft^2 per steam generator by the flow area of the steam generator outlet nozzles, and all steam generators were assumed to discharge through the break until steam line isolation had occurred.

6.3.2.4.4 CONCLUSIONS

The main steam line break transient was conservatively analyzed with respect to the reactor core response. Key analysis assumptions were made to conservatively maximize the cooldown of the Reactor Coolant System, so as to maximize the positive reactivity insertion, and thus maximize the peak return to power. Other key assumptions include: end-of-life shutdown margin with the most-reactive rod control cluster assembly stuck in its fully withdrawn position, maximum delays in actuating engineered safeguard features such as safety injection, main steam isolation and feedwater isolation, and minimum safety injection flow with a minimum boron concentration.

A departure from nucleate boiling ratio statepoint analysis was performed. The minimum departure from nucleate boiling ratio for each case was determined to be greater than the departure from nucleate boiling ratio safety analysis limit, and thus the departure from nucleate boiling design basis is met.

TABLE 6.3.2.1-1
SEQUENCE OF EVENTS FOR
FEEDWATER SYSTEM MALFUNCTION EVENT AT FULL POWER

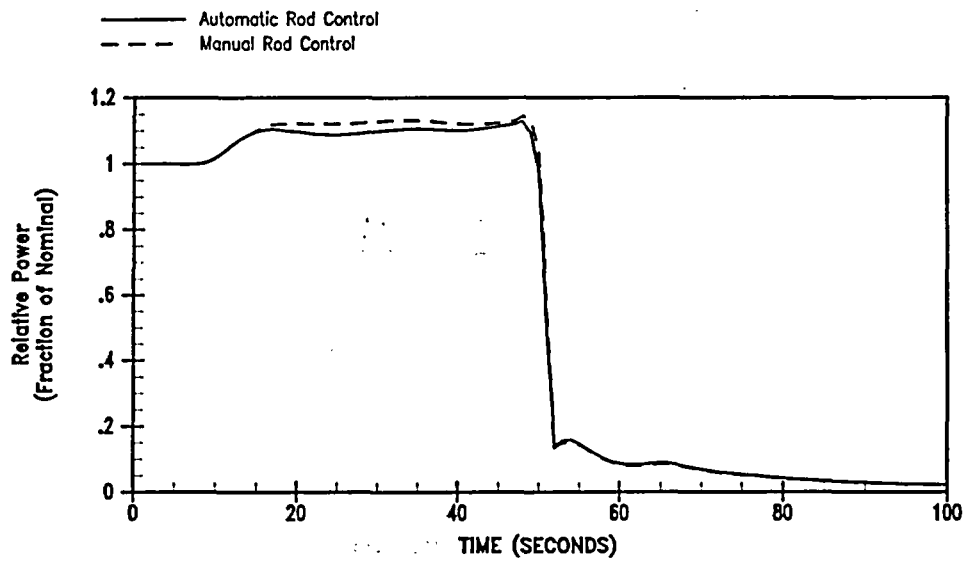
Event	Time (Seconds)	
	With Automatic Rod Control	Without Automatic Rod Control
Main feedwater control valve fail full open	0.1	0.1
Hi-Hi steam generator water level trip setpoint is reached	44.9	45.1
Turbine trip occurs due to Hi-Hi steam generator level	46.9	47.1
Minimum departure from nucleate boiling ratio occurs	48.0	48.0
Rod motion occurs	48.9	49.1
Feedwater isolation valves fully closed	56.9	57.1
Results		
Peak nuclear power, fraction of initial	1.128	1.143
Minimum departure from nucleate boiling ratio	2.185	2.153
Safety analysis limit departure from nucleate boiling ratio	1.47	1.47

TABLE 6.3.2.1-2
SEQUENCE OF EVENTS FOR
FEEDWATER SYSTEM MALFUNCTION EVENT AT ZERO POWER

Event	Time (Seconds)
Main feedwater control valves fail full open	0.0
Hi-Hi steam generator water level trip setpoint is reached	23.3
Turbine trip occurs due to Hi-Hi steam generator level	25.3
Feedwater isolation valves fully closed	35.3
Results	
Peak nuclear power, fraction of initial	0.120

TABLE 6.3.2.4-1
STEAM LINE BREAK ANALYSIS ASSUMPTIONS AND SEQUENCE OF EVENTS

	Double-Ended Rupture with Offsite Power
Time of main steam line rupture, seconds	0.01
Time maximum Auxiliary Feedwater (2395 gpm) Initiated, seconds	0.01
Time steam pressure reaches Lo-Lo setpoint (435 psia)	
-Faulted loop, seconds	0.54
-Unfaulted loops, seconds	1.00
Time of Safety Injection signal actuation due low steam pressure, seconds	2.54
Time of steam line isolation (main steam isolation valve closure) due to Safety Injection signal actuation, seconds	6.54
Time of feedwater isolation (main feedwater isolation valve closure) due to Safety Injection signal actuation, seconds	12.54
Time core returns to criticality, seconds	16.54
Time Safety Injection pump reaches full speed, seconds	27.55
Time of peak heat flux, seconds	138.47
Time of minimum departure from nucleate boiling ratio, seconds	158.20
Time accumulator tanks begin injecting into Reactor Coolant System, seconds	425.25
Peak heat flux, fraction of nominal	0.154
Minimum departure from nucleate boiling ratio	1.79



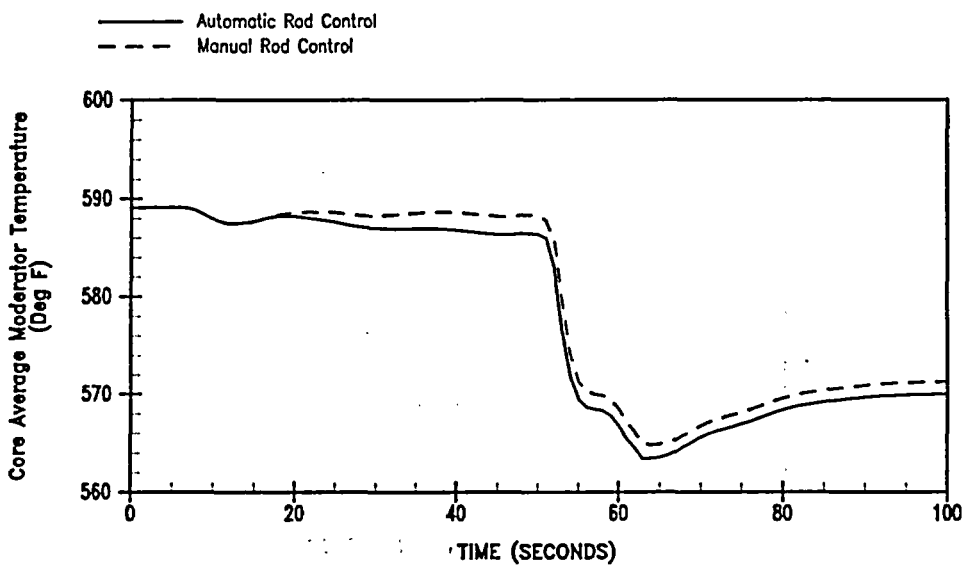


Figure 6.3.2.1-1
Relative Power and Core Average Moderator Temperature Transients for a Feedwater Control Valve Malfunction at Full Power

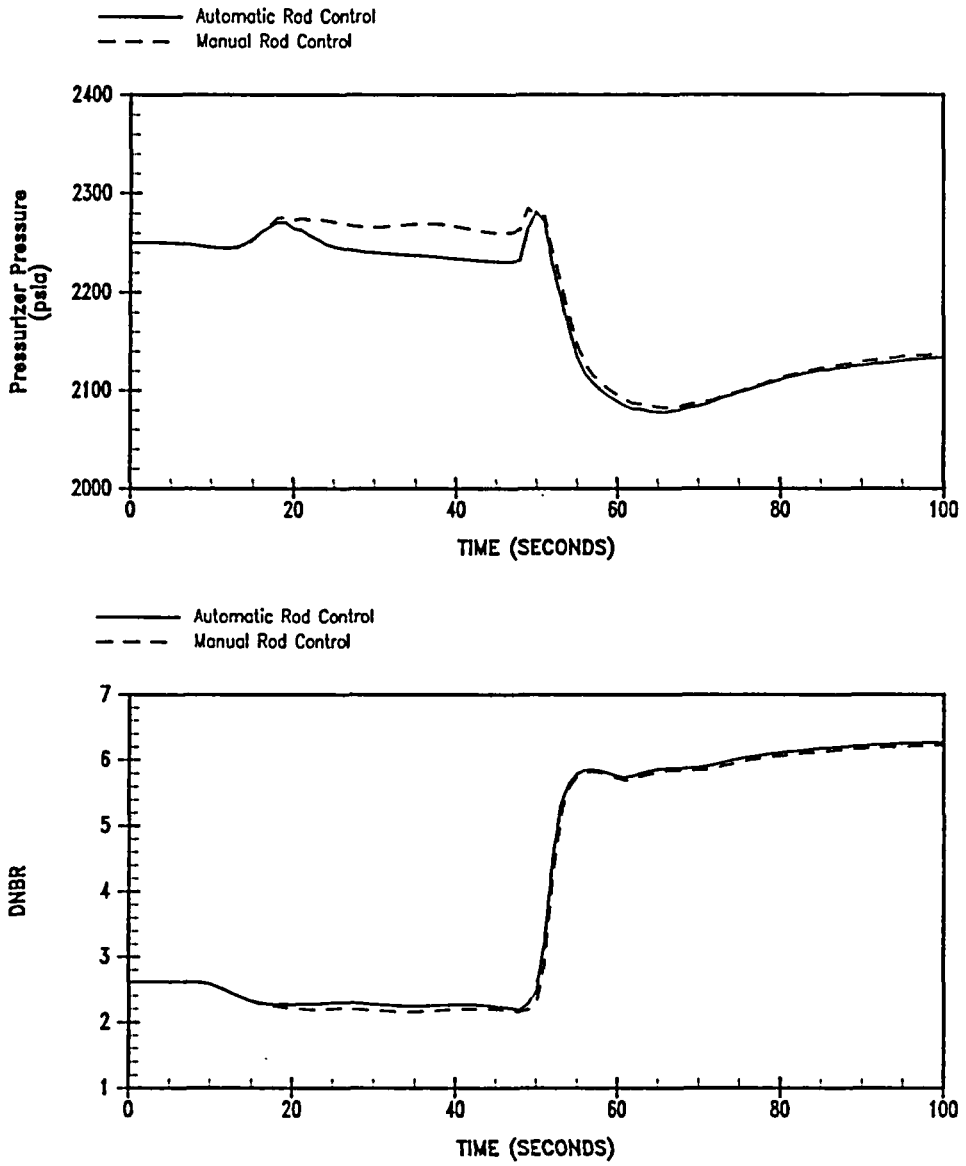


Figure 6.3.2.1-2
Pressurizer Pressure and Departure From Nucleate Boiling Ratio Transients for a Feedwater Control Valve Malfunction at Full Power

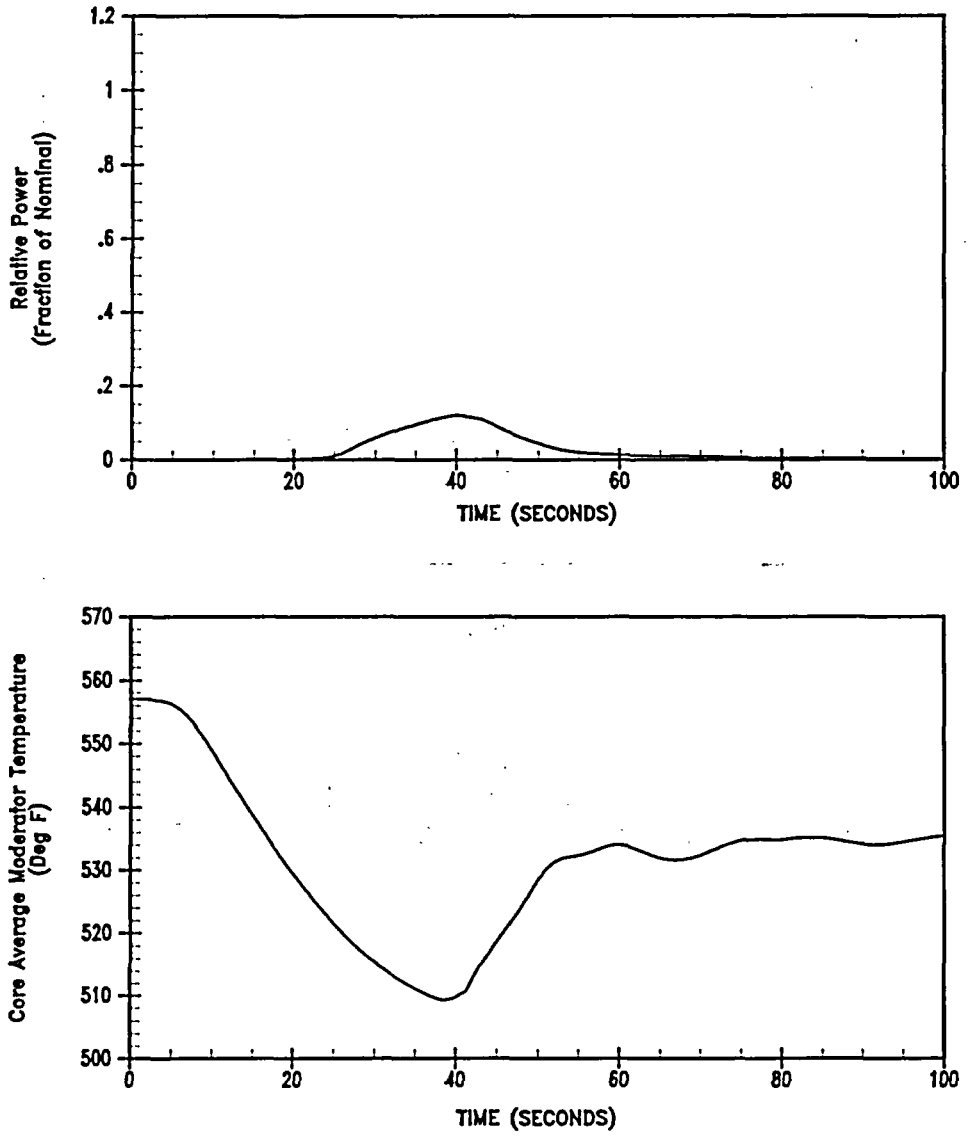


Figure 6.3.2.1-3
Relative Power and Core Average Moderator Temperature Transients for a Feedwater Control Valve Malfunction at Zero Power

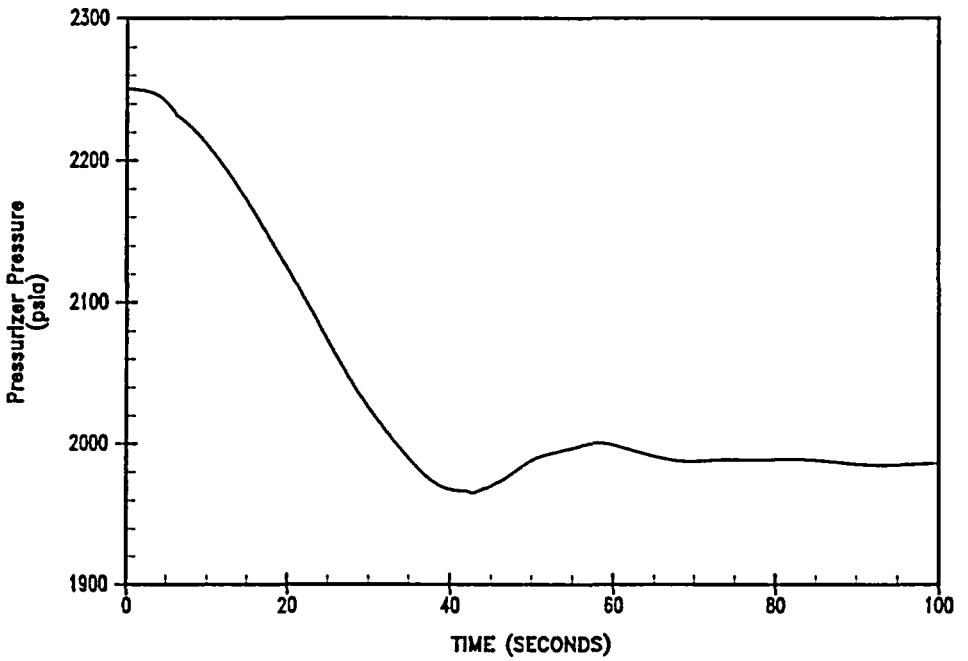


Figure 6.3.2.1-4
Pressurizer Pressure Transient
for a Feedwater Control Valve Malfunction at Zero Power

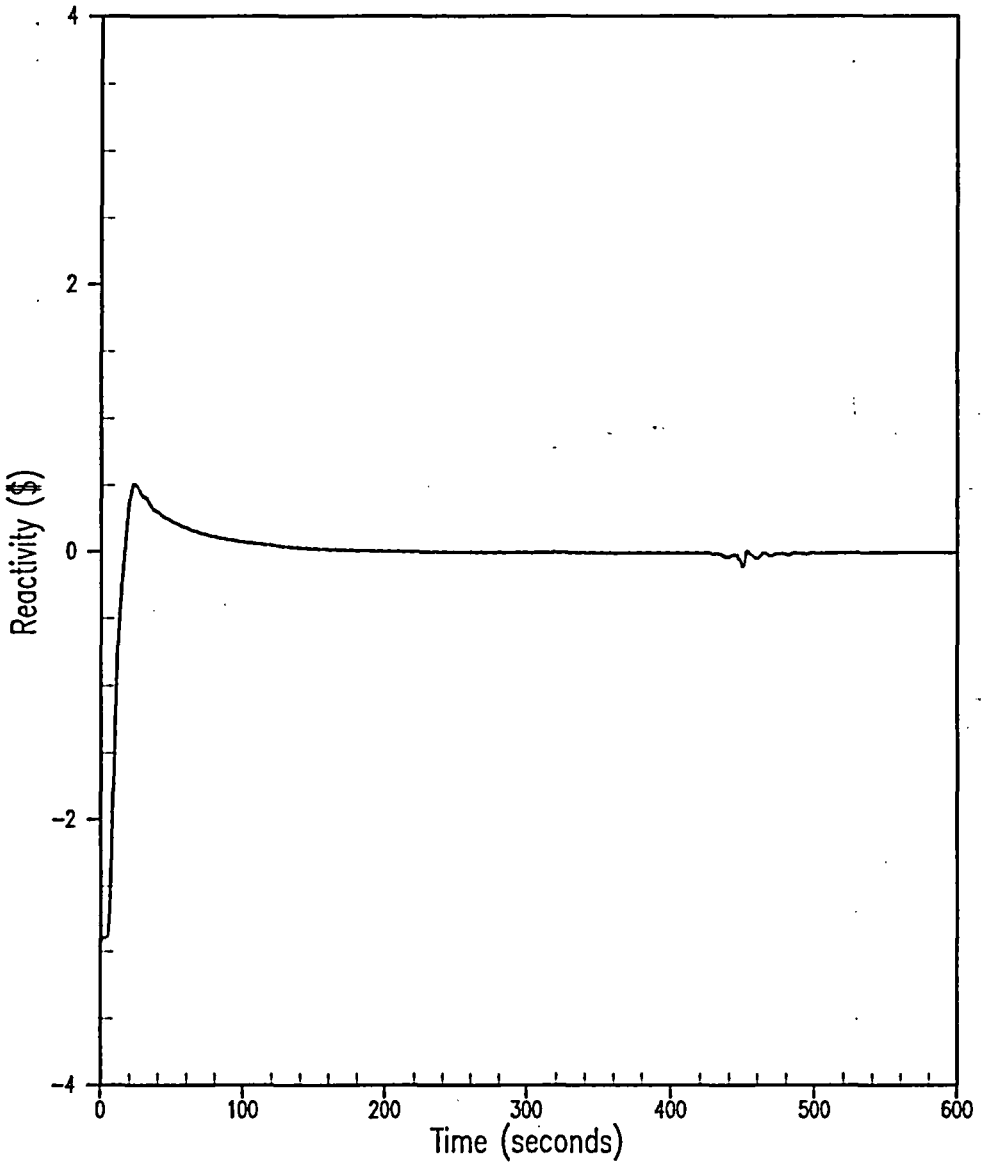


Figure 6.3.2.4-1
Main Steam Line Break with Offsite Power
Reactivity versus Time

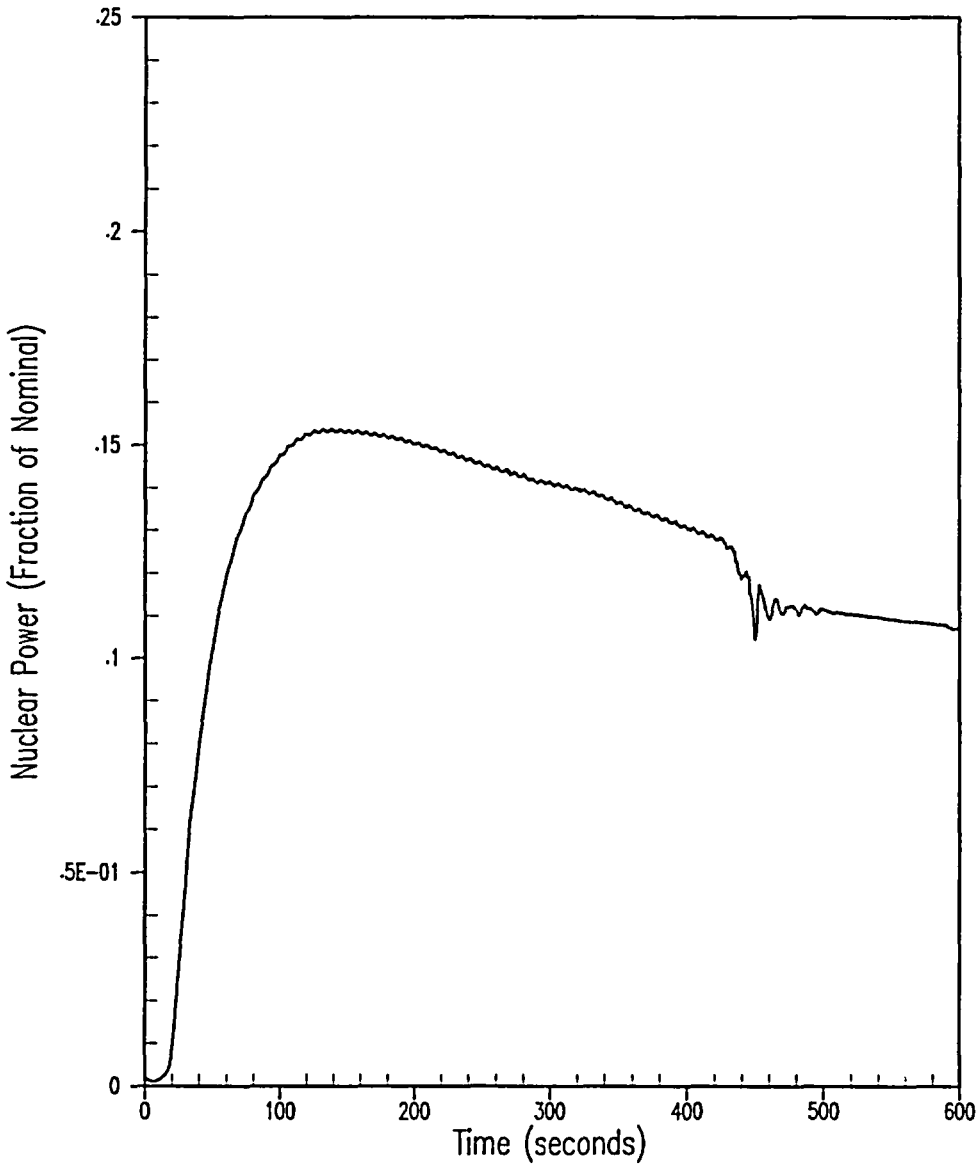


Figure 6.3.2.4-2
Main Steam Line Break with Offsite Power
Nuclear Power versus Time

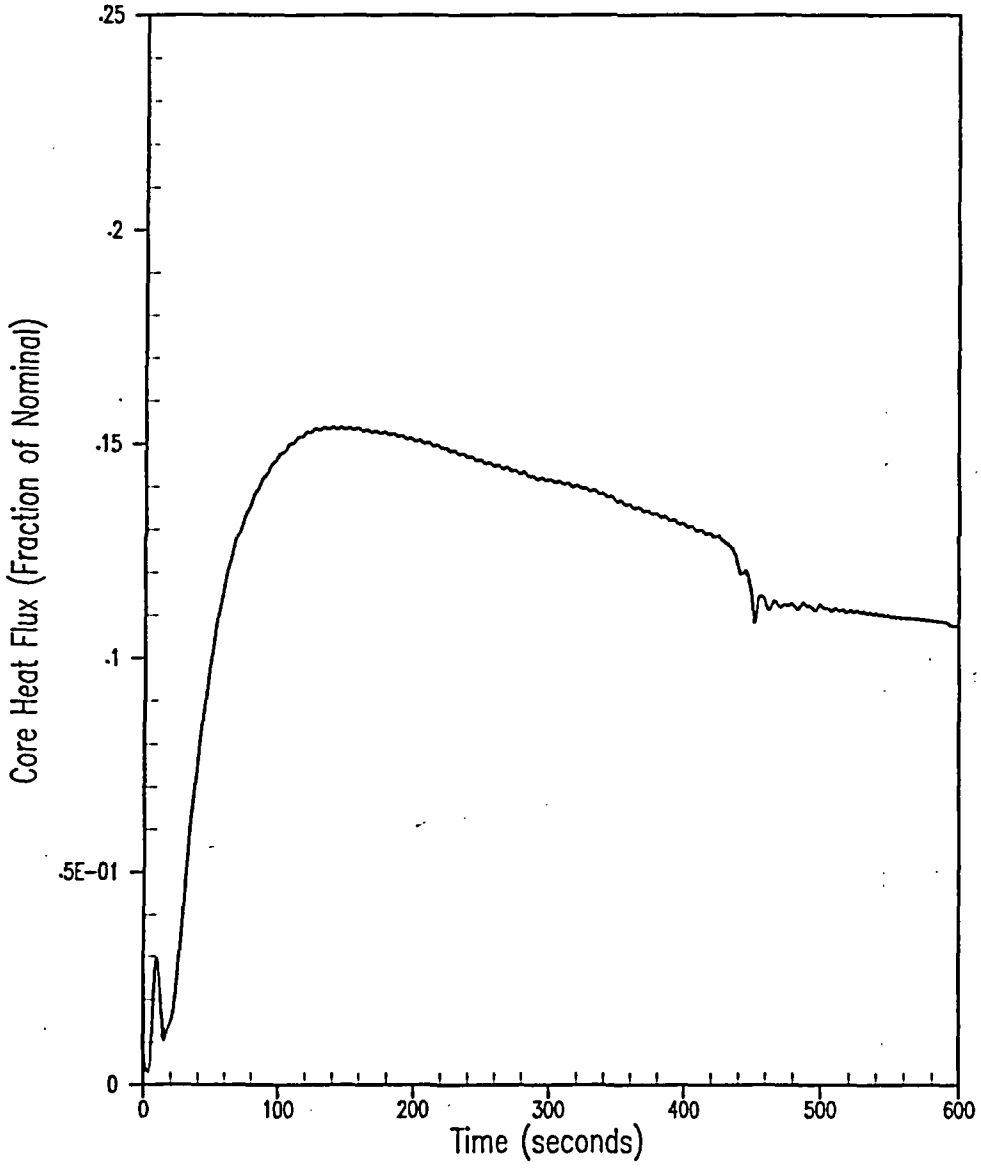


Figure 6.3.2.4-3
Main Steam Line Break with Offsite Power
Core Heat Flux versus Time

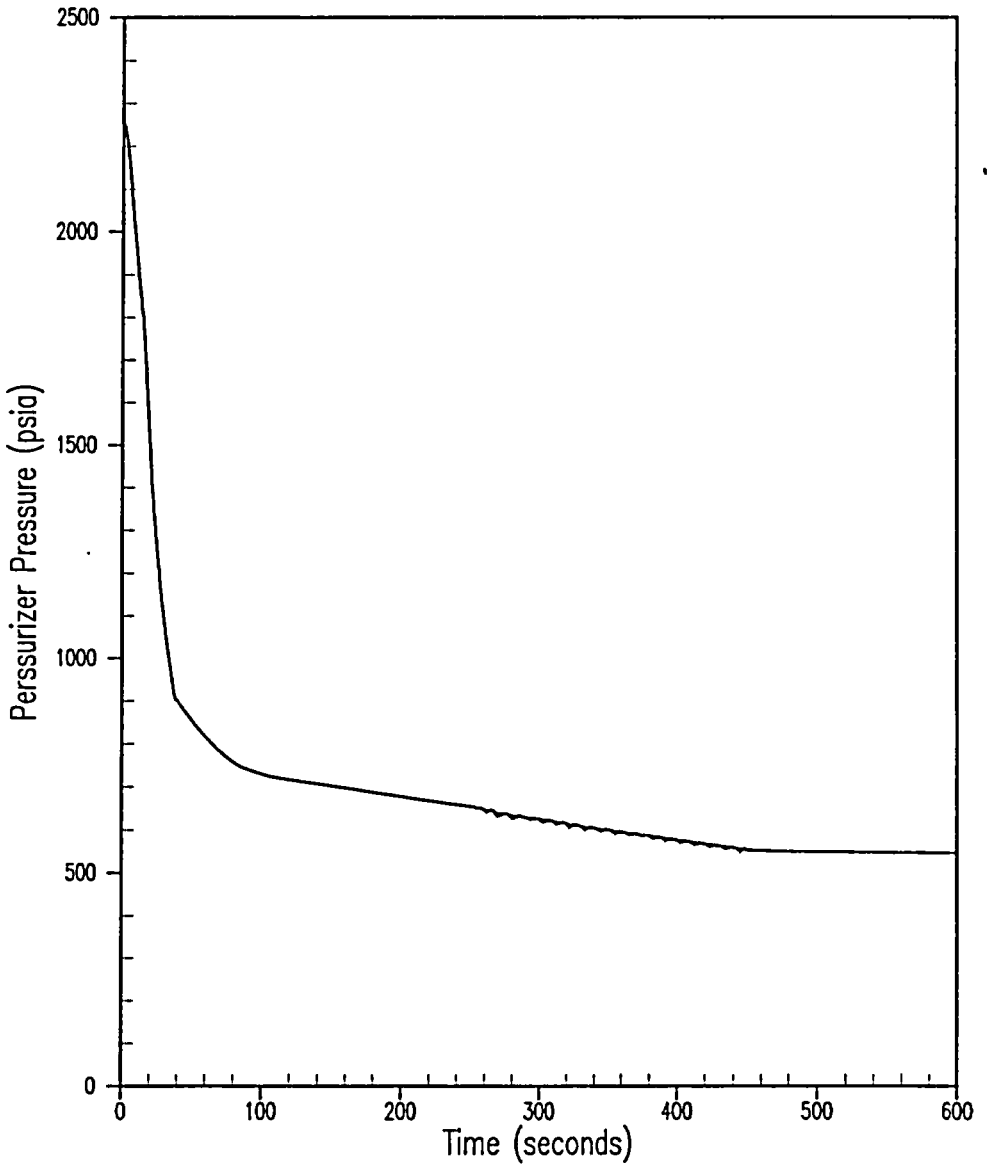


Figure 6.3.2.4-4
Main Steam Line Break with Offsite Power
Pressurizer Pressure versus Time

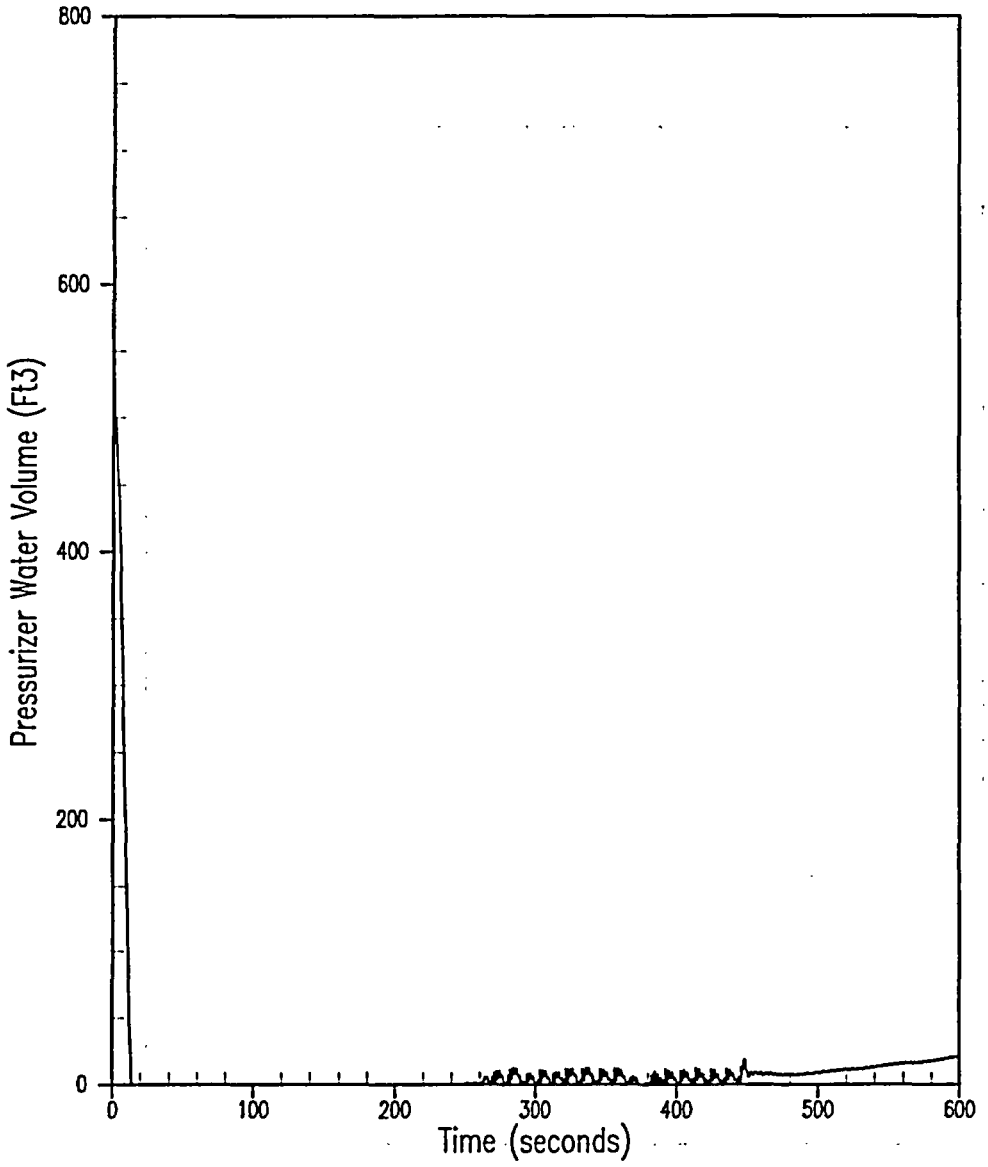


Figure 6.3.2.4-5
Main Steam Line Break with Offsite Power
Pressurizer Water Volume versus Time

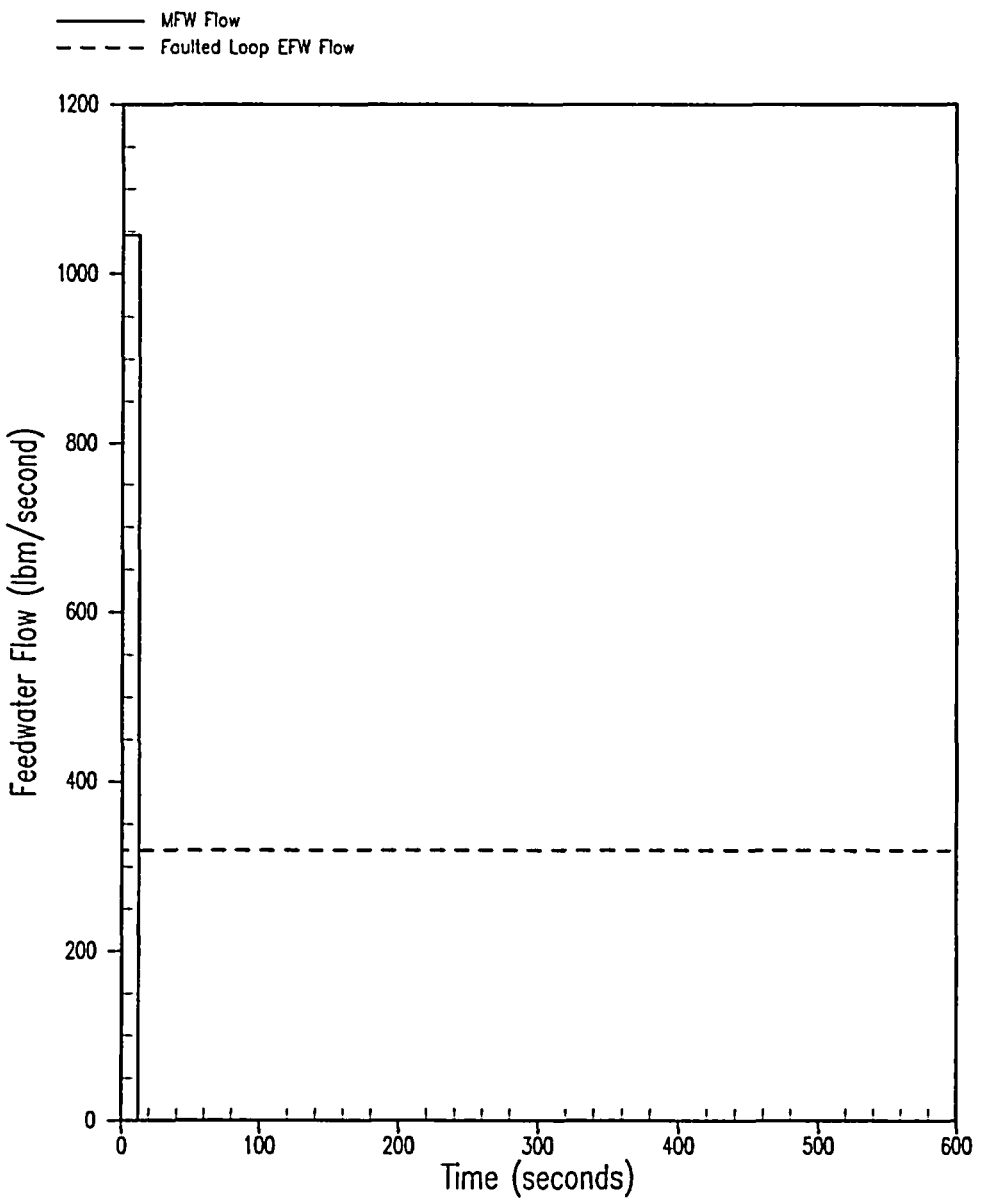


Figure 6.3.2.4-6
Main Steam Line Break with Offsite Power
Feedwater Flow versus Time

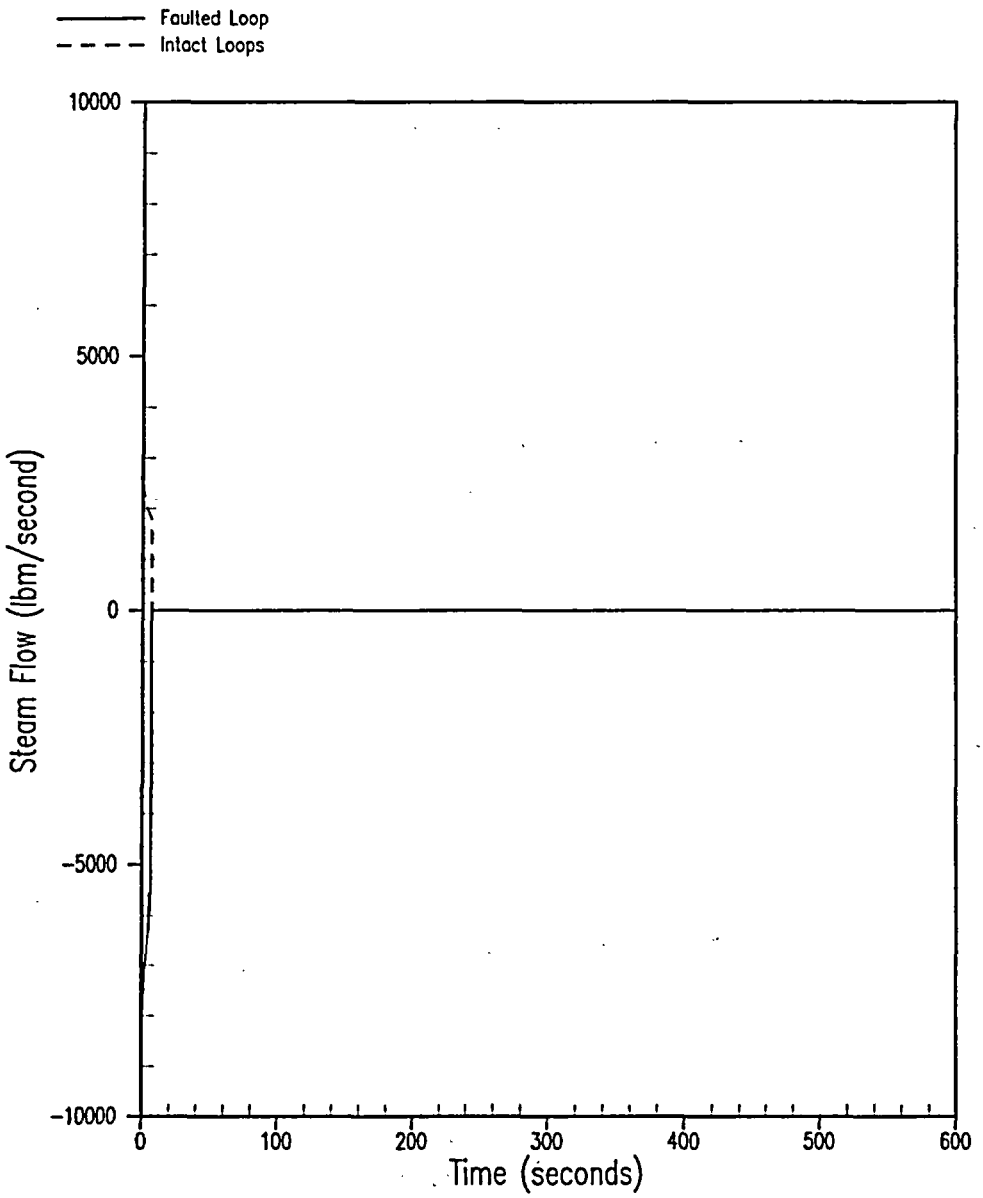


Figure 6.3.2.4-7
Main Steam Line Break with Offsite Power
Steam Flow versus Time

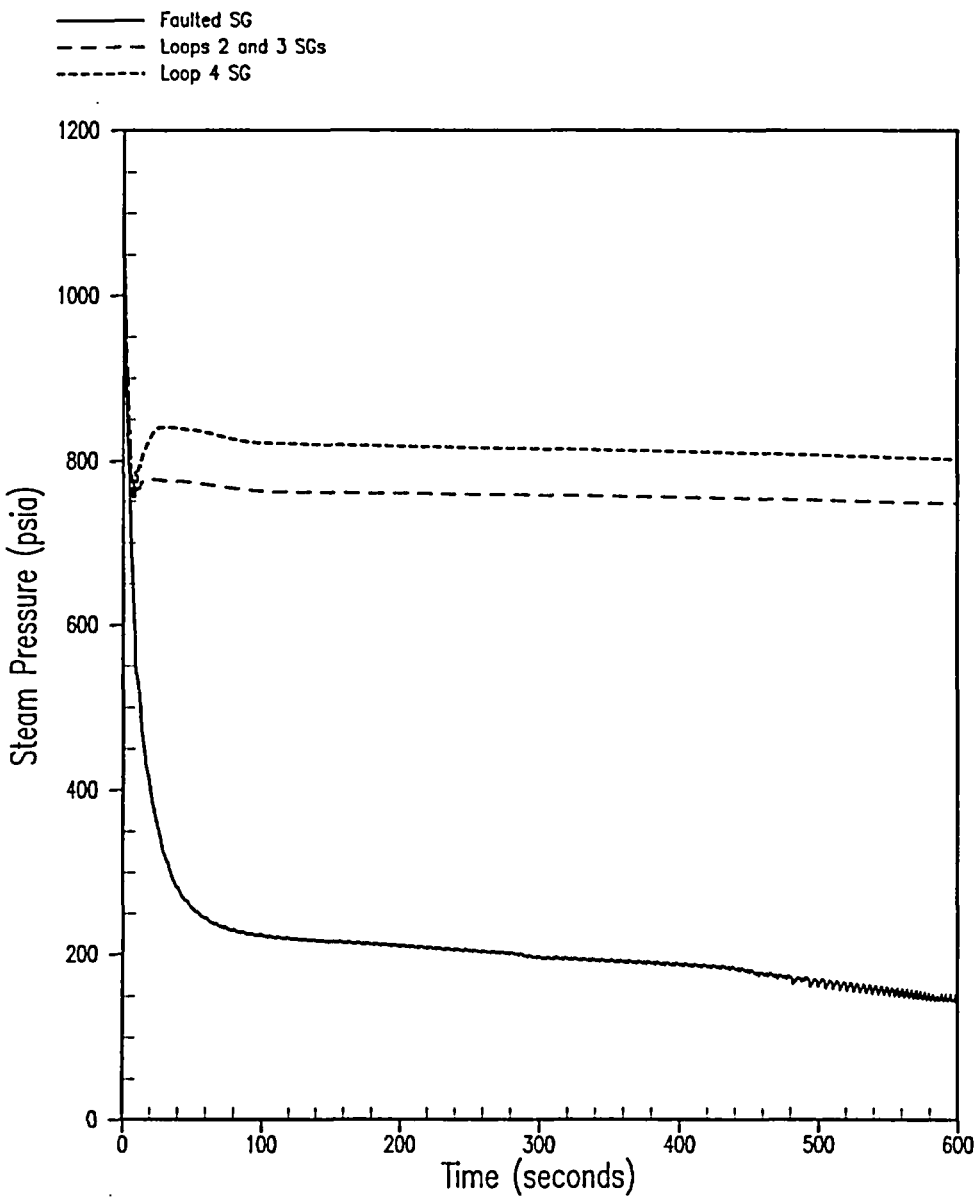


Figure 6.3.2.4-8
Main Steam Line Break with Offsite Power
Steam Pressure versus Time

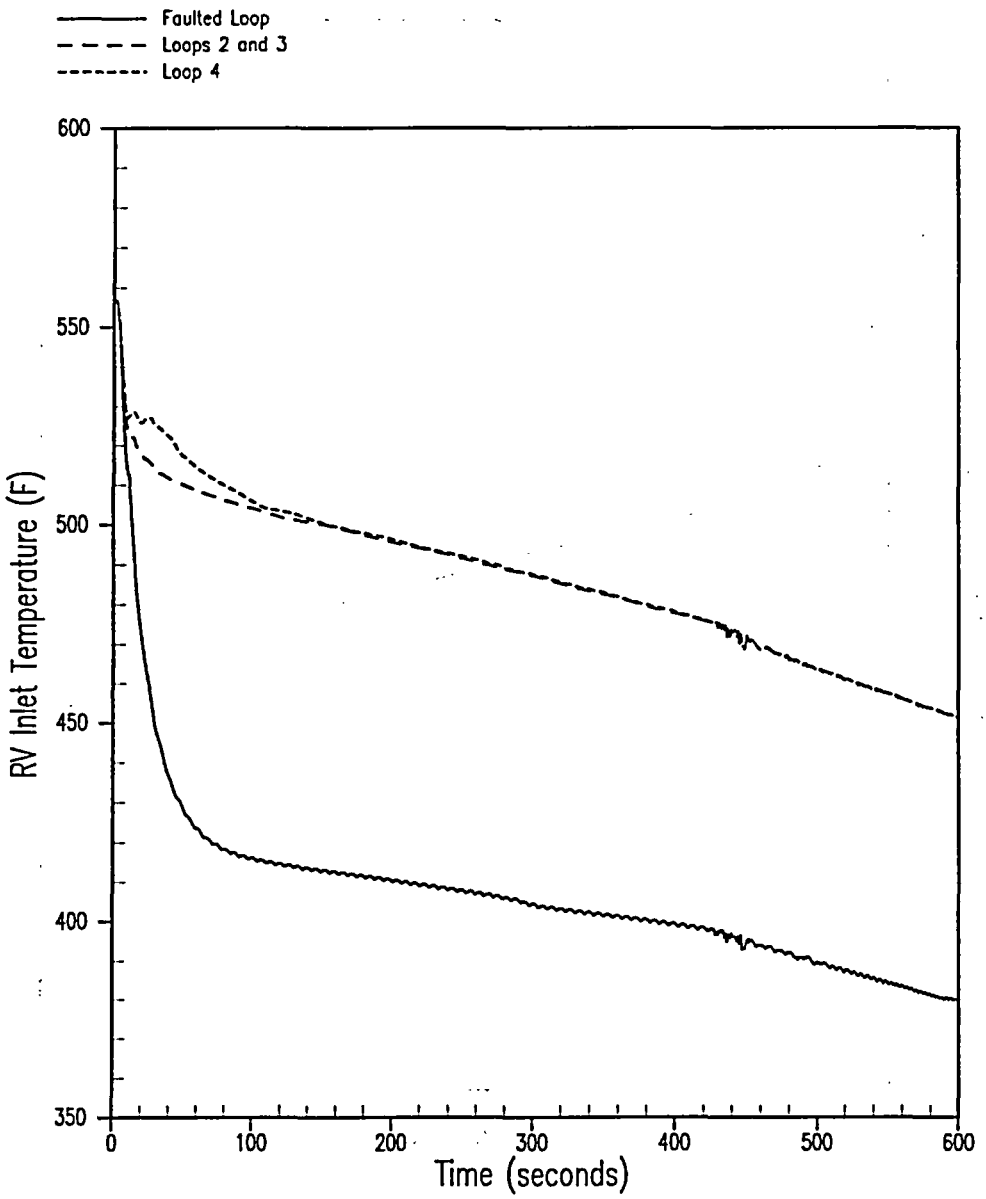
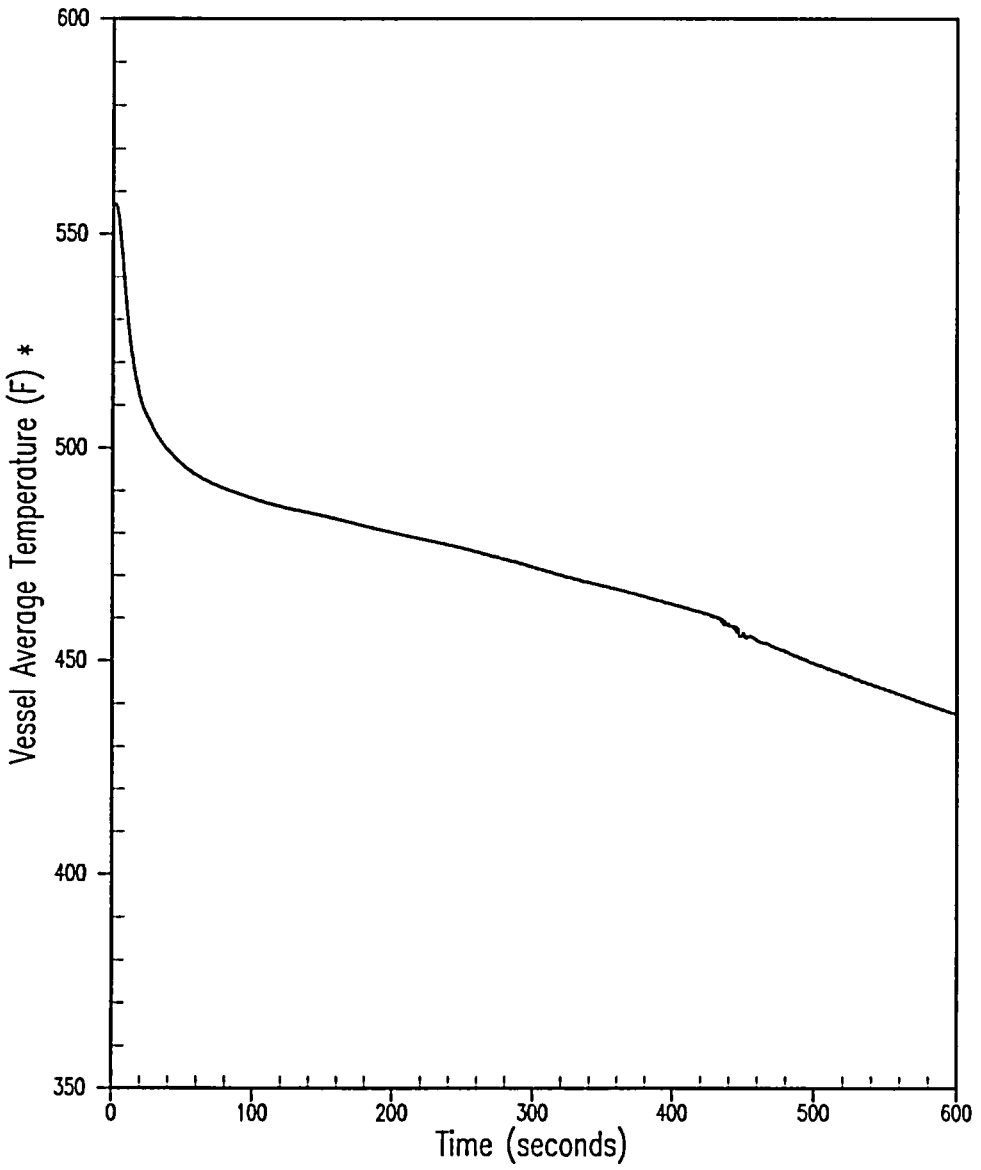


Figure 6.3.2.4-9
Main Steam Line Break with Offsite Power
Reactor Vessel Inlet Temperature versus Time



* Average of loop average temperatures

Figure 6.3.2.4-10
Main Steam Line Break with Offsite Power
Loop Average Temperature versus Time

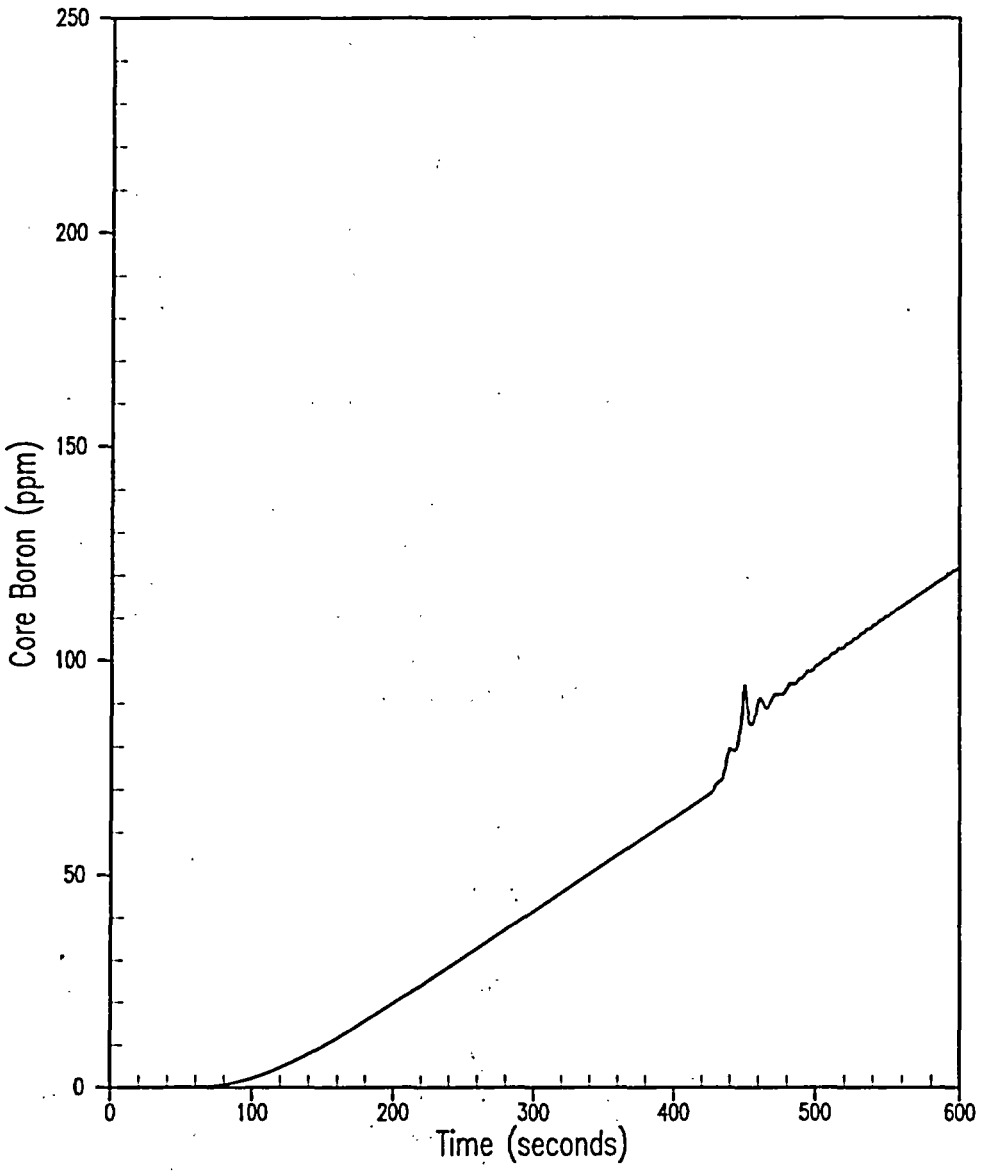


Figure 6.3.2.4-11
Main Steam Line Break with Offsite Power
Core Boron versus Time

6.3.3 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

6.3.3.1 LOSS OF EXTERNAL LOAD / TURBINE TRIP (SEABROOK STATION UFSAR SECTIONS 15.2.2 AND 15.2.3)

6.3.3.1.1 ACCIDENT DESCRIPTION

The loss-of-external-electrical-load event is defined as a complete loss of steam load or a turbine trip from full power without a direct reactor trip. This anticipated transient is analyzed as a turbine trip from full power because it bounds both events—the loss of external electrical load and turbine trip. The turbine-trip event is more severe than the total loss-of-external-electrical-load event since it results in a more rapid reduction in steam flow.

For a turbine trip, the reactor would be automatically tripped directly (unless below approximately 20-percent power) from a signal derived from either the turbine auto-stop oil pressure or a closure of the turbine stop valves. The automatic steam dump system accommodates the excess steam generation. Reactor coolant temperatures and pressures do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the turbine condenser were not available. For this situation, steam generator level would be maintained by the Emergency Feedwater System.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. The plant would be expected to trip from the Reactor Protection System. A continued steam load of approximately 5 percent would exist after a total loss of external electrical load because of the steam demand of plant auxiliaries.

In the event of a large loss of load in which the steam dump valves fail to open or a complete loss of load with the steam dump operating, the main steam safety valves may lift and the reactor may be tripped by any of the following signals: high pressurizer pressure, high pressurizer water level, overtemperature ΔT and overpower ΔT, or lo-lo steam generator water level. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves and main steam safety valves are sized to protect the Reactor Coolant System and steam generators against overpressure for all load losses without assuming the operation of the steam dump system. The steam dump valves will not be opened for load reductions of 10 percent or less, but may open for larger load reductions. The Reactor Coolant System and Main Steam System steam relieving capacities were designed to ensure safety of the unit without requiring automatic rod control, pressurizer pressure control, steam bypass control, or a reactor trip on turbine trip.

6.3.3.1.2 METHOD OF ANALYSIS

The loss-of-load transients are analyzed using the RETRAN computer code [Reference 6.3-1]. The code simulates the neutron kinetics, Reactor Coolant System,

pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power levels.

The loss-of-load accident is analyzed for the following:

- To confirm that the pressurizer safety valves and main steam safety valves are adequately sized to prevent overpressurization of the Reactor Coolant System and Main Steam System, respectively
- To ensure that the increase in Reactor Coolant System temperature does not result in a departure from nucleate boiling in the core

The Reactor Protection System is designed to automatically terminate a transient before the departure from nucleate boiling ratio falls below the limit value.

In this analysis, the behavior of the unit is evaluated for a complete loss-of-steam load from full power with no credit taken for a direct reactor trip on turbine trip. This assumption will delay reactor trip until conditions in the Reactor Coolant System cause a trip on some other signal. Therefore, the analysis assumes a worst-case transient and demonstrates the adequacy of the pressure-relieving devices and plant-specific Reactor Protection System setpoints assumed in the analysis for this event.

Of the three cases analyzed, one is performed to address departure from nucleate boiling concerns, one ensures that the peak Reactor Coolant System pressure remains below the design limit (2748.5 psia), and the final case confirms that the peak Main Steam System pressure remains below 110 percent of the steam generator shell design pressure (1318.5 psia). Of these three cases, only the first two have historically been presented in nuclear plant UFSARs. The major assumptions for these cases are summarized as follows:

1. For the case analyzed to demonstrate that the core thermal limits are adequately protected (beginning of cycle reactivity feedback conditions with automatic pressurizer pressure control), the loss-of-load accident is analyzed using the Revised Thermal Design Procedure [Reference 6.3-8]. For this case, initial core power, reactor coolant temperature, and reactor coolant pressure are assumed to be at the nominal values consistent with steady-state full-power operation. Uncertainties in initial conditions are included in determining the departure from nucleate boiling ratio limit value [Reference 6.3-8]. For the case analyzed to demonstrate the adequacy of the primary pressure-relieving devices (beginning of cycle reactivity feedback conditions without automatic pressurizer pressure control), the loss-of-load accident is analyzed using the Standard Thermal Design Procedure. For this case, initial core power, pressurizer pressure and reactor coolant temperature are assumed at their most limiting conditions, consistent with steady-state full-power operation, including allowances for calibration and instrument errors, where appropriate. For example, initial pressurizer pressure is assumed at the minimum value for this case, since it delays reactor trip on high pressurizer pressure and results in more severe primary-side temperature and pressure transients. Sensitivities to determine the most limiting initial Reactor Coolant System T_{avg} were

performed, consistent with NSAL-03-1 [Reference 6.3-24]. These initial conditions result in the maximum power difference for the loss of load. Similar to the Reactor Coolant System overpressurization case, the Main Steam System overpressurization case is analyzed assuming the Standard Thermal Design Procedure assumptions modeling the initial condition uncertainties in the most limiting direction. However, the Main Steam System overpressurization case differs from the Reactor Coolant System overpressurization case in that automatic pressurizer pressure control is assumed in order to delay reactor trip on overtemperature ΔT.

2. The loss-of-load event results in a primary-system heatup and, therefore, is conservatively analyzed assuming minimum reactivity feedback consistent with beginning of cycle conditions. This includes assuming a moderator temperature coefficient value consistent with beginning of cycle hot full power conditions (that is, zero moderator temperature coefficient) and a least negative Doppler power coefficient. Maximum feedback (end of life) cases that were previously considered in the Seabrook Station UFSAR are no longer analyzed since they have been determined to be non-limiting with respect to the minimum departure from nucleate boiling ratio, peak Reactor Coolant System pressure, and peak Main Steam System pressure.

3. It is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

4. No credit is taken for the operation of the steam dump system or steam generator power-operated relief valve. The steam generator pressure rises to the safety valve setpoints, where steam release through the main steam safety valve limits the secondary-side steam pressure to the setpoint values. The main steam safety valves are explicitly modeled in the loss-of-load licensing basis analysis assuming a +3.0-percent tolerance with a 5 psi pop to full open. The main steam safety valve model also assumes a 13 psi pressure drop from the steam generator exit to the main steam safety valve inlet in determining the opening setpoints and an additional 35 psi pressure drop at full-open and full-flow conditions. Justification for the use of the 5 psi pop instead of modeling accumulation is based on test data documented in WCAP-10105 [Reference 6.3-10] and WCAP-12910 [Reference 6.3-7]. Note that by maximizing the pressure transient in the Main Steam System, the saturation temperature in the steam generators is maximized, resulting in limiting pressure and temperature conditions in the Reactor Coolant System.

5. The modeling of the pressurizer pressure control is as follows for the three cases analyzed:

   - For the case analyzed for departure from nucleate boiling, automatic pressurizer pressure control is assumed. Therefore, full credit is taken for the effect of the pressurizer spray and power operated relief valves in reducing or limiting the primary coolant pressure. Safety valves are also available and are modeled assuming a –3 percent setpoint tolerance.

- For the case analyzed for Reactor Coolant System overpressure concerns, it is assumed that automatic pressurizer pressure control is not available. Therefore, no credit is taken for the effect of the pressurizer spray or power operated relief valves in reducing or limiting the primary coolant pressure. Safety valves are assumed operable, but are modeled assuming a +3 percent setpoint tolerance.
- For the case analyzed for Main Steam System overpressure concerns, automatic pressurizer pressure control is assumed to be available. Credit is taken for the effect of the pressurizer spray and power operated relief valves in reducing or limiting the primary coolant pressure, therefore conservatively delaying the actuation of the Reactor Protection System until an overtemperature ΔT reactor trip signal is generated. Delaying the reactor trip ensures that the energy input to the secondary system, and subsequently the Main Steam System pressure, is maximized.

6. Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for Emergency Feedwater System flow since a stabilized plant condition will be reached before Emergency Feedwater System initiation is normally assumed to occur for full-power cases. However, the Emergency Feedwater System pumps would be expected to actuate following a loss of normal feedwater. The Emergency Feedwater System flow would remove core decay heat following plant stabilization.
7. The analysis is performed for operation with robust fuel assembly fuel and a maximum steam generator tube plugging level (uniform) of 10 percent.
8. Reactor trip is actuated by overtemperature ΔT or high pressurizer pressure.

6.3.3.1.3 RESULTS

The transient responses for a total loss of load from full-power operation are shown in LAR Figures 6.3.3.1-1 through 6.3.3.1-16 for the 3 cases assuming beginning of cycle reactivity feedback conditions with and without automatic pressurizer pressure control (pressurizer spray and power operated relief valves).

LAR Figures 6.3.3.1-1 through 6.3.3.1-6 show the transient responses for the total loss of steam load at beginning of cycle (minimum feedback reactivity coefficients) assuming full credit for the pressurizer spray and power operated relief valves to calculate the transient departure from nucleate boiling ratio response. Following event initiation, the pressurizer pressure and average Reactor Coolant System temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure and water volume and Reactor Coolant System average temperature are reached shortly after the reactor is tripped by the overtemperature ΔT trip function. The departure from nucleate boiling ratio initially increases slightly, then decreases until the reactor trip occurs. Finally, following reactor trip, it increases rapidly. The minimum departure from nucleate boiling ratio remains well above the safety analysis limit value. The main steam safety valves actuate to limit the Main Steam System pressure below 110 percent of the steam generator shell design

pressure. LAR Table 6.3.3.1-1 summarizes the sequence of events and limiting conditions for this case.

The total loss-of-load event was also analyzed assuming the plant to be initially operating at full power at beginning of cycle with no credit taken for the pressurizer spray or power operated relief valves to maximize the Reactor Coolant System pressure response. LAR Figures 6.3.3.1-7 through 6.3.3.1-11 show the transients for this case. The nuclear power remains relatively constant prior to reactor trip, while pressurizer pressure, pressurizer water volume, and Reactor Coolant System average temperature increase due to the sudden reduction in primary to secondary heat transfer. The reactor is tripped on the high pressurizer pressure trip signal. In this case, the pressurizer safety valves are actuated and maintain the primary-side pressure below 110 percent of the design value. The main steam safety valves actuate to limit the Main Steam System pressure below 110 percent of the steam generator shell design pressure. LAR Table 6.3.3.1-2 summarizes the sequence of events and limiting conditions for this case.

LAR Figures 6.3.3.1-12 through 6.3.3.1-16 show the transient responses for the total loss of steam load at beginning of cycle (minimum feedback reactivity coefficients) assuming full credit for the pressurizer spray and power operated relief valves to maximize the Main Steam System pressure response. Following event initiation, the pressurizer pressure and average Reactor Coolant System temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure and water volume and Reactor Coolant System average temperature are reached shortly after the reactor is tripped by the overtemperature ΔT trip function. The Main Steam System pressure increases, resulting in the actuation of the first four main steam safety valves, and then decreases rapidly following reactor trip. The main steam safety valves actuate to limit the Main Steam System pressure below 110 percent of the steam generator shell design pressure. LAR Table 6.3.3.1-3 summarizes the sequence of events and limiting conditions for this case.

6.3.3.1.4 CONCLUSIONS

The results of the analyses show that the plant design is such that a total loss of external electrical load without a direct or immediate reactor trip presents no hazard to the integrity of the Reactor Coolant System or Main Steam System. Pressure-relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits; that is, 2748.5 psia for the Reactor Coolant System and 1318.5 psia for the Main Steam System.

The integrity of the core is maintained by operation of the Reactor Protection System; that is, the minimum departure from nucleate boiling ratio is maintained above the safety analysis limit value of 1.47. Therefore, no core safety limit will be violated as a result of implementing the SPU.

6.3.3.2 LOSS OF NORMAL FEEDWATER FLOW (SEABROOK STATION UFSAR SECTION 15.2.7)

6.3.3.2.1 ACCIDENT DESCRIPTION

A loss of normal feedwater (from a pipe break, pump failure, or valve malfunction) results in a reduction of the ability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, core damage could possibly occur from a sudden loss of heat sink. If an alternate supply of feedwater were not supplied to the steam generators, residual heat following reactor trip and reactor coolant pump heat would heat the primary system water to the point where water relief from the pressurizer would occur, resulting in a substantial loss of water from the Reactor Coolant System. A significant loss of water from the Reactor Coolant System could conceivably lead to core damage. Since the reactor is tripped well before the steam generator heat transfer capability is reduced, the Reactor Coolant System never approaches a condition where the departure from nucleate boiling ratio limit may be violated.

The following features provide protection against a loss of normal feedwater:

- Reactor trip on low-low water level in any steam generator
- Automatic start of one emergency feedwater pump on low-low water level in any steam generator

The analysis is performed to show that following a loss of normal feedwater, the Emergency Feedwater System is capable of removing the stored energy, residual decay heat and reactor coolant pump heat. This is shown by demonstrating that the pressurizer is prevented from becoming water-solid, which could lead to overpressurization of the Reactor Coolant System and a subsequent loss of water from the Reactor Coolant System via a pressurizer relief or safety valve.

With respect to system overpressure concerns, the Loss of Normal Feedwater event is bounded by the Loss of Load / Turbine Trip event analysis (minimum reactivity feedback, without pressure control). For the Loss of Normal Feedwater event, turbine trip occurs after reactor trip, whereas for Loss of Load / Turbine Trip the turbine trip is the initiating fault. Therefore, the primary / secondary power mismatch and resultant Reactor Coolant System and main steam system heatup and pressurization transients are always more severe for Loss of Load / Turbine Trip than for Loss of Normal Feedwater.

Likewise, the departure from nucleate boiling ratio consequences of the Loss of Normal Feedwater event are bounded by the Loss of Load / Turbine Trip event. Both of these events represent a reduction in the heat removal capability of the secondary system. For the Loss of Normal Feedwater event, the Reactor Coolant System 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 Loss of Load / Turbine Trip event, the turbine trip is the initiating event, and the loss of heat sink is much more severe. Therefore, the initial Reactor Coolant System heatup will be much more severe for the Loss of Load / Turbine Trip event than for the Loss of Normal Feedwater event,

and the Loss of Load / Turbine Trip event will always be more severe with respect to the minimum departure from nucleate boiling ratio criterion.

Therefore, the single acceptance criterion for the Loss of Normal Feedwater analysis is that the pressurizer does not become water solid.

6.3.3.2.2 METHOD OF ANALYSIS

The loss of normal feedwater transient is analyzed using the RETRAN computer code. The RETRAN model simulates the Reactor Coolant System, neutron kinetics, pressurizer, pressurizer relief and safety valves, pressurizer heaters, pressurizer spray, steam generators, feedwater system, and main steam safety valves. The code computes pertinent plant variables including steam generator mass, pressurizer water volume, and reactor coolant average temperature.

The major assumptions are summarized below.

1. The plant is initially operating at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The reactor coolant pumps run throughout the transient.
2. The initial reactor coolant vessel average temperature is assumed to be 584.1 °F. Sensitivity analyses demonstrated that this initial coolant temperature is conservative.
3. The initial pressurizer pressure is assumed to be 2300 psia (the nominal value of 2250 psia plus 50 psi uncertainty). Sensitivity analyses demonstrated that a high initial pressurizer pressure is conservative.
4. The initial pressurizer water level is assumed to be 65 percent level. A high initial pressurizer water level is conservative because it minimizes the initial margin to filling the pressurizer water-solid.
5. The initial steam generator water level is assumed to be 58 percent of narrow range span (the programmed full-power value of 50 percent plus 8 percent narrow range span uncertainty). A high initial steam generator water level is conservative because it maximizes the time to reach the steam generator low-low water level, thus increasing the primary system heat input.
6. The transient is simulated by terminating main feedwater flow at 20 seconds.
7. Reactor trip occurs on steam generator low-low water level at 0 percent narrow range span. Turbine trip occurs as a result of reactor trip.
8. Seventy-seven seconds after the low-low steam generator water level setpoint is reached, a minimum constant Emergency Feedwater flow of 650 gpm is initiated from one emergency feedwater pump, with flow split equally between the four steam generators. This assumption considers the limiting single failure of one emergency feedwater pump. The emergency feedwater enthalpy is assumed to be 71.16 BTU/lbm (100°F at 1200 psia).

9. Secondary system steam relief is achieved through the main steam safety valves. The main steam safety valves opening pressures are the nominal settings plus a 3 percent tolerance.
10. Normal reactor control systems are not assumed to be operable if their operation leads to less limiting analysis results. However, the pressurizer power-operated relief valves, pressurizer heaters, and pressurizer sprays are assumed to operate normally, since this results in a conservative transient with respect to the peak pressurizer water volume. If these control systems did not operate, the pressurizer safety valves would maintain peak Reactor Coolant System pressure below 110 percent of the design value.
11. A conservative core residual heat generation is assumed based on the American Nuclear Society 5.1-1979 decay heat model plus 2 sigma [Reference 6.3-11].
12. The initial normal feedwater temperature is assumed to be 390°F. Sensitivity analyses demonstrated that this initial feedwater temperature is slightly more conservative than the higher value (452.4°F).
13. The steam generator tube plugging level is assumed to be 10%. Sensitivity analyses demonstrated that this is slightly more conservative than 0%.
14. The limiting case assumes minimum reactivity feedback conditions and a maximum Doppler power coefficient.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the Reactor Protection System to trip the reactor and Emergency Feedwater System to remove long-term decay heat, stored energy, and reactor coolant pump heat. This prevents excessive heatup or overpressurization of the Reactor Coolant System. As such, the assumptions used in the analysis are designed to maximize the time to reactor trip and to minimize the energy removal capability of the Emergency Feedwater System. These assumptions maximize the possibility of water relief from the Reactor Coolant System by maximizing the expansion of the Reactor Coolant System inventory, as noted in the assumptions listed above.

6.3.3.2.3 RESULTS

LAR Figures 6.3.3.2-1 through 6.3.3.2-6 show the significant plant responses following a loss of normal feedwater. The calculated sequence of events and results are listed in LAR Table 6.3.3.2-1.

Following the reactor and turbine trip from full load, the water level in each steam generator falls due to the reduction of the steam generator void fraction, and because steam flow through the main steam safety valves continues to dissipate the stored and generated heat. Seventy-seven seconds after the initiation of the low-low level trip, flow from the available emergency feedwater pump begins, thus reducing the rate of water level decrease in the steam generators.

The capacity of one emergency feedwater pump is sufficient to dissipate core residual heat, stored energy, and reactor coolant pump heat such that the pressurizer does not fill water-solid. LAR Figure 6.3.3.2-4 shows the pressurizer water volume transient.

Note that while an initial peak is reached around the time of reactor trip, this peak is quickly reduced due to the trip and has no bearing on the demonstration of the ability of the Emergency Feedwater System to remove the stored energy, residual decay heat and reactor coolant pump heat. The calculated long term peak pressurizer water volume is 1175 ft^3 (at 1055 seconds) compared to the total pressurizer volume limit of 1834.4 ft^3. Plant procedures may be followed to further cool down the plant.

As noted previously, the maximum Reactor Coolant System and Main Steam System pressures for this event are bounded by the loss of external electrical load analysis, which demonstrates that the peak pressures remain below 110 percent of the respective design limit values. The departure from nucleate boiling ratio is not evaluated for this analysis since it is bounded by the loss of external electrical load analysis, for which the initial reactor coolant heatup is more severe.

6.3.3.2.4 CONCLUSIONS

The results of the loss of normal feedwater analysis show that the single applicable acceptance criterion of not filling the pressurizer is satisfied. The Emergency Feedwater System capacity is sufficient to dissipate core residual heat, stored energy, and reactor coolant pump heat such that reactor coolant is not relieved through the pressurizer relief or safety valves.

6.3.3.3 LOSS OF NONEMERGENCY AC POWER TO THE PLANT AUXILIARIES (LOSS OF OFFSITE POWER) (SEABROOK STATION UFSAR SECTION 15.2.6)

6.3.3.3.1 ACCIDENT DESCRIPTION

A complete loss of nonemergency AC power results in the loss of all power to the plant auxiliaries; such as the reactor coolant pumps, main feedwater and condensate pumps, etc. 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 distribution system.

The events following a loss of AC power are described in Seabrook Station UFSAR Section 15.2.6. The Emergency Feedwater System is started automatically, as discussed for the loss of normal feedwater analysis (LAR Section 6.3.3.2).

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops. Following the reactor coolant pump coastdown caused by the loss of AC power, the natural circulation capability of the Reactor Coolant System removes residual and decay heat from the core, aided by the emergency feedwater in the secondary system.

6.3.3.3.2 METHOD OF ANALYSIS

The loss of nonemergency AC power to the plant auxiliaries transient is analyzed using the RETRAN computer code. The code simulates the neutron kinetics, Reactor Coolant System including natural circulation, pressurizer, pressurizer relief and safety valves,

pressurizer heaters, pressurizer spray, steam generators, feedwater system, and main steam safety valves. The code computes pertinent plant variables including steam generator mass, pressurizer water volume, and reactor coolant average temperature.

The analysis does not assume that power is lost as the initiating event. Rather, the analysis conservatively models a loss of normal feedwater with a subsequent loss of offsite power following the reactor trip on low-low steam generator water level. This bounds the case of an immediate loss of nonemergency AC power as the initiating event, which would result in an immediate reactor trip.

Major assumptions made in the loss of nonemergency AC power analysis are the same as those made in the loss of normal feedwater analysis (LAR Section 6.3.3.2), with the following exceptions.

1. The reactor coolant pumps are assumed to lose power and begin coasting down 2 seconds following the reactor trip on low-low steam generator water level. Following the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and removal of residual heat is maintained by natural circulation flow in the coolant loops. Heat addition from the reactor coolant pumps to the primary coolant ceases.
2. Pressurizer sprays are lost when forced reactor coolant flow ceases as a result of reactor coolant pump coastdown.
3. The steam generator tube plugging level is assumed to be 0%. Sensitivity analyses demonstrated that this is slightly more conservative than 10%.

6.3.3.3.3 RESULTS

LAR Figures 6.3.3.3-1 through 6.3.3.3-6 show the significant plant responses following a loss of nonemergency AC power to the plant auxiliaries. The calculated sequence of events and results are listed in LAR Table 6.3.3.3-1.

Following the reactor and turbine trip from full load, the water level in each steam generator falls due to the reduction of the steam generator void fraction, and because steam flow through the steam generator main steam safety valves continues to dissipate the stored and generated heat. Seventy-seven seconds after the initiation of the low-low level trip, flow from the available emergency feed pump begins, thus reducing the rate of water level decrease in the steam generators.

The capacity of one emergency feedwater pump is sufficient to dissipate core residual heat and stored energy such that the pressurizer does not fill water-solid, with natural circulation flow conditions in the Reactor Coolant System. LAR Figure 6.3.3.3-4 shows the pressurizer water volume transients. Note that while an initial peak is reached around the time of reactor trip, this peak is quickly reduced due to the trip and has no bearing on the demonstration of the ability of the Emergency Feedwater System to remove the stored energy and residual decay heat. The calculated long term peak pressurizer water volume is 1463 ft^3 (at 1300 seconds) compared to the total pressurizer volume limit of 1834.4 ft^3. Plant procedures may be followed to further cool down the plant.

The maximum Reactor Coolant System and main steam system pressures for this event are bounded by the loss of external electrical load analysis, which demonstrates that the peak pressures remain below 110 percent of the respective design limit values. For the loss of nonemergency AC power event, turbine trip occurs after reactor trip, whereas for loss of external electrical load analysis the turbine trip is the initiating fault. Therefore, the primary / secondary power mismatch and resultant Reactor Coolant System and Main Steam System heatup and pressurization transients are always more severe for loss of external electrical load than for loss of nonemergency AC power.

In addition, when a loss of nonemergency AC power is the initiating event, the first few seconds of the transient will closely resemble the simulation of the complete loss of reactor coolant flow event (Seabrook Station UFSAR Section 15.3.2), where departure from nucleate boiling and core damage due to rapidly increasing core temperature is prevented by promptly tripping the reactor. For the loss of nonemergency AC power scenario analyzed, the departure from nucleate boiling ratio results are less limiting since the reactor is already tripped when reactor coolant pump coastdown begins. Thus, the departure from nucleate boiling ratio is not evaluated for this event since it would be bounded by the loss of reactor coolant flow analysis.

6.3.3.3.4 CONCLUSIONS

The results of the loss of nonemergency AC power to the plant auxiliaries analysis show that the single applicable acceptance criterion is satisfied. The Emergency Feedwater System capacity is sufficient to dissipate core residual heat and stored energy such that reactor coolant is not relieved through the pressurizer relief or safety valves.

6.3.3.4 FEEDWATER SYSTEM PIPE BREAK (SEABROOK STATION UFSAR SECTION 15.2.8)

6.3.3.4.1 ACCIDENT DESCRIPTION

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory. If the break is postulated in a feedwater line between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. A break in this location could preclude the subsequent addition of emergency feedwater to the affected steam generator. Also, all emergency feedwater flow is assumed to be lost through the break prior to isolation of emergency feedwater flow to the faulted steam generator. A break upstream of the feedwater line check valve would affect the NSSS only as a loss of feedwater, which is covered by the analyses of the loss of normal feedwater and loss of AC power to the plant auxiliaries events.

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a Reactor Coolant System cooldown (by excessive discharge through the break) or a Reactor Coolant System heatup. Potential Reactor Coolant System cooldown resulting from a secondary pipe rupture is bounded by the analysis of the steamline break event. Therefore, only the Reactor Coolant System heatup effects are evaluated for a feedwater line rupture.

This event is analyzed in order to evaluate the capacity of the Emergency Feedwater System to remove core decay heat and to ensure that the core remains in a coolable geometry. In order to demonstrate this, a more limiting criterion is imposed such that the hot and cold leg temperatures must remain below the saturation temperature until the emergency feedwater heat removal capability exceeds the Reactor Coolant System heat generation, which demonstrates that the core remains covered with water. The analysis also demonstrates that the primary and secondary pressures remain within 110% of their design pressure.

The following features provide reactor protection and ensure that a coolable core geometry is maintained in the event of a main feedwater line rupture:

- A reactor trip on any of the following conditions:
  - High pressurizer pressure
  - Overtemperature ΔT
  - Low-low steam generator water level in any steam generator
  - Safety injection signals from any of the following:

    (a) Two out of three low steam line pressure in any one loop,

    (b) Two out of three high containment pressure (hi-1), or

    (c) Low pressurizer pressure.
- An Emergency Feedwater System to provide an assured source of feedwater to the steam generators for decay heat removal.

Receipt of a low-low steam generator water level signal in at least one steam generator starts both the motor-driven emergency feedwater pump and turbine-driven emergency feedwater pump, which in turn initiates emergency feedwater flow to the steam generators. Similarly, receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal which closes all main steam line isolation valves. This signal also generates a safety injection signal which initiates flow of cold borated water into the Reactor Coolant System. The amount of safety injection flow is a function of Reactor Coolant System pressure.

Two Emergency Feedwater System configurations were considered. In the first configuration, both emergency feedwater pumps were assumed to operate; however, the emergency feedwater flow control valve to one intact steam generator was assumed to fail closed (single failure). As a result, only two intact steam generators receive emergency feedwater following the break. The flow restrictor and control valves on the faulted loop limit the flow spilling out the break to 750 gpm prior to control valve closure. The flow through the open control valves to the remaining two intact loops is at least 235 gpm each, ensuring the minimum required flow of 470 gpm. The second configuration considered operation of only one of the two emergency feedwater pumps (single failure), providing flow to all three intact steam generators. Flow from the operating emergency feedwater pump spills out of the break in the faulted loop prior to automatic closure of one of the redundant flow control valves. With the control valve

closed, the intact steam generators in combination will receive the minimum required emergency feedwater flow of 470 gpm. The analysis presented was performed using the second configuration. This configuration is slightly more conservative because it maximizes the time elapsed prior to cold emergency feedwater reaching the intact steam generators.

The analysis shows that following a feedwater line rupture, the Emergency Feedwater System is capable of removing the stored energy, residual decay and reactor coolant pump heat, thus ensuring that the core remains covered with water.

6.3.3.4.2 METHOD OF ANALYSIS

The feedwater line rupture event is classified as a Condition IV event, a limiting fault, as defined by the American Nuclear Society. Condition IV events are limiting faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material. Specifically, the feedwater line rupture analysis is performed to demonstrate the adequacy of the Reactor Protection System and engineered safeguards features (such as the Emergency Feedwater System) to remove long-term decay heat, stored energy, and reactor coolant pump heat, to prevent overpressurization of the Reactor Coolant System, and to prevent reactor core uncovery (ensures that a coolable geometry is maintained). As such, the assumptions used in the analysis are designed to minimize the energy removal capability of the system.

For the feedline water rupture event, the RETRAN computer code is used to generate the power transient associated with the event. Based on that power transient, the code calculates the temperature of the Reactor Coolant System at various points, which is then compared to the saturation temperature of the Reactor Coolant System. By demonstrating that the hot and cold leg temperatures remain below the saturation temperature, the core remains covered throughout the transient.

The major assumptions are summarized below. The assumptions are made to conservatively maximize the Reactor Coolant System fluid temperatures and minimize the saturation temperature.

1. The plant is initially operating at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), which includes calorimetric uncertainties.
2. The initial reactor coolant average temperature is 595.1 °F, which corresponds to the high nominal full-power coolant average temperature value of 589.1°F plus uncertainty (6°F).
3. The initial pressurizer pressure is assumed to be 2200 psia, which corresponds to the nominal value of 2250 psia minus uncertainty (50 psi).
4. The initial Reactor Coolant System flow is assumed to be symmetric in each loop; however a 2°F penalty is applied to the analysis results to conservatively address asymmetric Reactor Coolant System flow associated with steam generator tube plugging asymmetry.

5. Normal reactor control systems are not assumed to function unless their function results in more severe consequences. Therefore, the pressurizer power operated relief valves are assumed to operate normally in order to minimize the Reactor Coolant System pressure, which results in a lower saturation temperature.
6. The initial pressurizer water level is assumed to be at the nominal value plus uncertainty (5% narrow range span).
7. The initial steam generator water level is assumed to be 8% narrow range span above the nominal programmed value for the faulted steam generator, and 14.5% narrow range span below the nominal programmed value for the intact steam generators.
8. The worst case assumes minimum reactivity feedback - zero moderator density coefficients, least negative Doppler temperature coefficients, least negative Doppler-only power coefficients and maximum delayed neutron beta-effective values.
9. Main feedwater to all steam generators is assumed to stop at the time the break occurs (all main feedwater spills out through the break).
10. The worst possible break area, a double-ended guillotine rupture downstream of the emergency feedwater connection, is assumed. This maximizes the blowdown discharge rate following the time of trip, which maximizes the resultant heatup of the reactor coolant.
11. Choked flow is assumed at the break with a high blowdown quality prior to reactor trip, resulting in an increase in the time required to obtain reactor trip. The blowdown quality after reactor trip corresponds to saturated water until the point at which all liquid inventory in the faulted steam generator is lost, resulting in a decrease in the heat removal capability of the faulted steam generator. After the liquid mass is depleted, the blowdown becomes saturated steam.
12. The analysis assumes a conservatively low value of 0% narrow range span for the steam generator low-low level setpoint, which provides the reactor trip and actuates the Emergency Feedwater System.
13. Turbine trip is assumed to occur 0.5 seconds after break initiation and no credit is taken for the atmospheric steam dump valves.
14. Emergency feedwater pump performance is based on the loss of one train (single failure) and minimum flow versus steam generator back pressure injected to the three intact steam generators by one operational emergency feedwater pump. Cold emergency feedwater is assumed to not reach the steam generators until the three feedwater branch lines have been swept clear of hot feedwater.
15. One of the redundant emergency feedwater flow control valves leading to the faulted steam generator is assumed to close on a high flow rate signal with a bounding stroke time of 23 seconds to terminate emergency feedwater flow to the faulted steam generator. This stroke time is conservatively modeled as an additional delay over and above the emergency feedwater signal delay (2 seconds) and the delay for emergency feedwater pump start (77 seconds).

16. Emergency feedwater is assumed to be at a conservatively high temperature of 100°F.
17. Safety injection actuation is credited on low pressurizer pressure.
18. Minimum high head Emergency Core Cooling System pump performance and maximum Emergency Core Cooling System temperature (98°F) are assumed. The flow rates assumed conservatively account for flow from only one centrifugal charging pump with 10% head degradation.
19. No credit is taken for heat transfer to the Reactor Coolant System piping metal during the event.
20. Steam generator heat transfer area is assumed to decrease as the shell side liquid inventory decreases.
21. A conservative core residual heat generation is assumed based on the American Nuclear Society Standard 5.1-1979 decay heat standard, including 2 sigma uncertainty.
22. No credit is taken for the following potential protection logic signals to mitigate the consequences of the accident:
    - High pressurizer pressure
    - Overtemperature ΔT
    - High pressurizer level.

The feedwater line rupture analysis considered four cases, 2 maximum reactivity feedback cases, with and without offsite power available and 2 minimum reactivity feedback cases, with and without offsite power available.

The maximum reactivity feedback cases assumed most positive moderator density coefficients, most negative Doppler temperature coefficients, most negative Doppler-only power coefficients and minimum delayed neutron beta-effective values.

The minimum reactivity feedback cases assumed zero moderator density coefficients, least negative Doppler temperature coefficients, least negative Doppler-only power coefficients and maximum delayed neutron beta-effective values.

The minimum reactivity feedback case with offsite power available was determined to be the most limiting case; as such the results presented herein correspond to this case.

6.3.3.4.3 RESULTS

Calculated plant parameters following a major feedwater line rupture are shown in LAR Figures 6.3.3.4-1 through 6.3.3.4-5. The calculated sequence of events is listed in LAR Table 6.3.3.4-1.

The Reactor Coolant System heatup prior to reactor trip is due to loss of the secondary system heat sink as a result of main feedwater spillage through the break and the increased secondary system temperature and pressure following the turbine trip. Reactor power increases slightly prior to the trip due to the Reactor Coolant System

heatup. The primary and secondary systems were calculated to remain below 110 percent of their respective design pressures.

Following the reactor trip, steam flow out the break cools the Reactor Coolant System and eventually causes Reactor Coolant System pressure to decrease and the pressurizer to empty resulting in Safety Injection initiation on a low pressurizer pressure signal. The core remains covered with water as demonstrated by the fact that the coolant loops do not reach a saturated condition. Low main steam line pressure causes closure of the main steam isolation valves and ends the cooldown period. Addition of safety injection flow aids in cooling down the primary and ensures that sufficient fluid exists to keep the core covered with water.

The main steam isolation valve closure and resulting increase in steam generator pressure and temperature causes a second Reactor Coolant System heatup. As a result, the rising primary system pressure exceeds the shutoff head of the Emergency Core Cooling System pumps and then increases to the pressurizer power operated relief valve setpoint. The heatup continues until the intact steam generators reach their main steam safety valve setpoint. Once the heat removal due to the capacity of the combination of steam relief through the main steam safety valves and emergency feedwater injection exceeds the core decay heat plus reactor coolant pump heat, the adequacy of the Emergency Feedwater System is demonstrated and the event is terminated.

The maximum hot and cold leg temperatures remain below the saturation temperature throughout the transient. Therefore, it is demonstrated that the core remains covered with water throughout the event and that no fuel damage occurs. This event is bounded by the loss of external electrical load event with respect to peak Reactor Coolant System and Main Steam System pressure concerns. With respect to departure from nucleate boiling concerns, the steamline break event bounds the event.

6.3.3.4.4 CONCLUSIONS

Results of the analyses show that for the postulated feedwater line rupture, the Emergency Feedwater System capacity is adequate to remove decay and reactor coolant pump heat. Subsequently, the Emergency Feedwater System provides sufficient primary-to-secondary heat transfer to prevent uncovery of the reactor core, as demonstrated by the fact that the hot and cold leg temperatures remain below the saturation temperature throughout the transient. Therefore, it is demonstrated that the core remains in a coolable geometry in the event that a feedwater line rupture occurs.

TABLE 6.3.3.1-1
SEQUENCE OF EVENTS AND TRANSIENT RESULTS
LOSS OF EXTERNAL ELECTRICAL LOAD
WITH PRESSURIZER PRESSURE CONTROL
(FOR MINIMUM DEPARTURE FROM NUCLEATE BOILING)

Event	Time (seconds)
Turbine trip	0.0
Reactor trip on overtemperature ΔT	10.6
Rod motion begins	12.6
Time of minimum departure from nucleate boiling ratio	13.0
Time of peak Main Steam System pressure	17.0
Minimum departure from nucleate boiling ratio value	1.83
Departure from nucleate boiling ratio limit	1.47
Peak Main Steam System pressure	1296.7 psia
Main Steam System pressure limit	1318.5 psia

TABLE 6.3.3.1-2
SEQUENCE OF EVENTS AND TRANSIENT RESULTS
LOSS OF EXTERNAL ELECTRICAL LOAD
WITHOUT PRESSURIZER PRESSURE CONTROL
(FOR REACTOR COOLANT SYSTEM OVERPRESSURE)

Event	Time (seconds)
Turbine trip	0.0
Reactor trip on high pressurizer pressure	5.9
Rod motion begins	7.9
Time of peak Reactor Coolant System pressure	8.5
Time of peak Main Steam System pressure	13.5
Peak Reactor Coolant System pressure	2681.9 psia
Reactor Coolant System pressure limit	2748.5 psia
Peak Main Steam System pressure	1279.0 psia
Main Steam System pressure limit	1318.5 psia

TABLE 6.3.3.1-3

SEQUENCE OF EVENTS AND TRANSIENT RESULTS LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURIZER PRESSURE CONTROL (FOR MAIN STEAM SYSTEM OVERPRESSURE)

Event	Time (seconds)
Turbine trip	0.0
Reactor trip on overtemperature ΔT	8.4
Rod motion begins	9.5
Time of peak Reactor Coolant System pressure	10.4
Time of peak Main Steam System pressure	15.5
Peak Reactor Coolant System pressure	2305.7 psia
Reactor Coolant System pressure limit	2748.5 psia
Peak Main Steam System pressure	1302.8 psia
Main Steam System pressure limit	1318.5 psia

TABLE 6.3.3.2-1
SEQUENCE OF EVENTS
LOSS OF NORMAL FEEDWATER

Event	Time (seconds)
Main Feedwater flow stops	20.0
Low-low steam generator water level trip setpoint reached	58.7
Rods begin to drop	60.7
Emergency Feedwater flow is initiated from one pump	135.7
Core decay heat (plus reactor coolant pump heat) decreases to Emergency Feedwater System heat removal capacity	~1000
Long term peak water volume in the pressurizer occurs*	1055
* Long term peak pressurizer water volume	1175 ft^3
Pressurizer water volume limit	1834.4 ft^3

TABLE 6.3.3.3-1
SEQUENCE OF EVENTS
LOSS OF NONEMERGENCY AC POWER TO THE PLANT AUXILIARIES

Event	Time seconds)
Main Feedwater flow stops	20.0
Low-low steam generator water level trip setpoint reached	58.7
Rods begin to drop	60.7
Reactor coolant pumps begin to coast down	62.7
Emergency Feedwater Flow is Initiated from one pump	135.7
Core decay heat decreases to Emergency Feedwater System heat removal capacity	300
Long term peak water volume in the pressurizer occurs*	1300
* Long term peak pressurizer water volume	1463 ft^3
Pressurizer water volume limit	1834.4 ft^3

TABLE 6.3.3.4-1
SEQUENCE OF EVENTS
FEEDWATER LINE RUPTURE

Event	Time (seconds)
Main Feedwater line rupture occurs and Main Feedwater flow is terminated to all intact loops	0.0
Low-low steam generator water level reactor trip setpoint reached in broken loop	5.0
Rods begin to drop	7.0
Low pressurizer pressure reached for Safety Injection System injection	76.3
Safety Injection flow is started	103.3
Emergency Feedwater flow of 470 gpm (total) to three intact steam generator is started	105.0
Low steamline isolation setpoint is reached	114.5
All main steamline isolation valves are closed	118.5
Minimum margin to hot-leg saturation (15.3°F) occurs*	121.0
Steam generator safety valves open in steam generators of intact loops	810.1
Heat transfer capability of the intact steam generator exceeds the NSSS heat generation (i.e., transient turnaround)	~4000

* A 2°F penalty has been applied to the analysis results to address Reactor Coolant System flow asymmetry due to the potential for a loop-to-loop plugging imbalance of up to 10%.

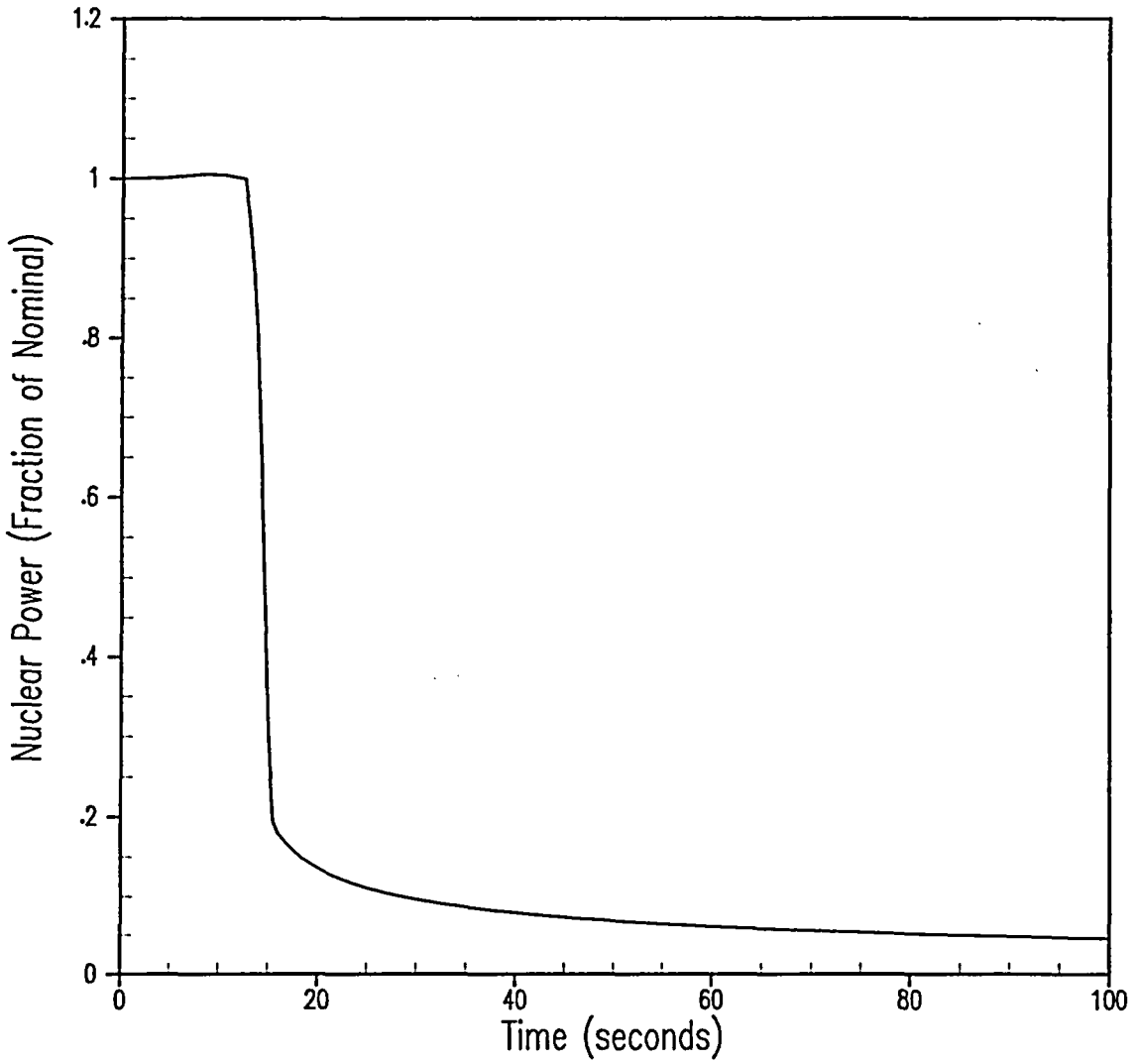


Figure 6.3.3.1-1
Loss of External Electrical Load with Automatic Pressure Control
(Departure from Nucleate Boiling Case)
Nuclear Power versus Time

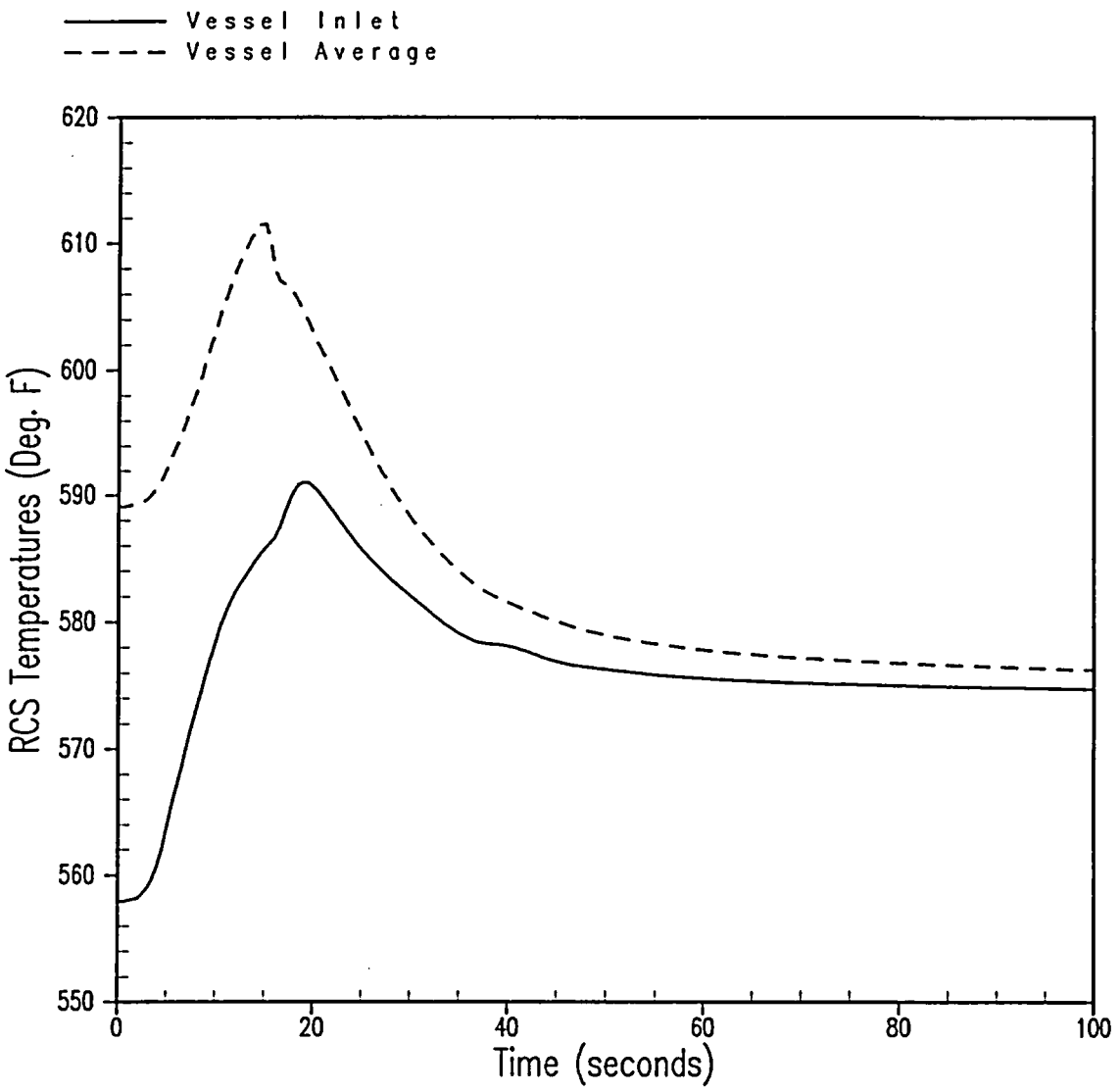


Figure 6.3.3.1-2
Loss of External Electrical Load with Automatic Pressure Control
(Departure from Nucleate Boiling Case)
Vessel Average and Inlet Temperatures versus Time

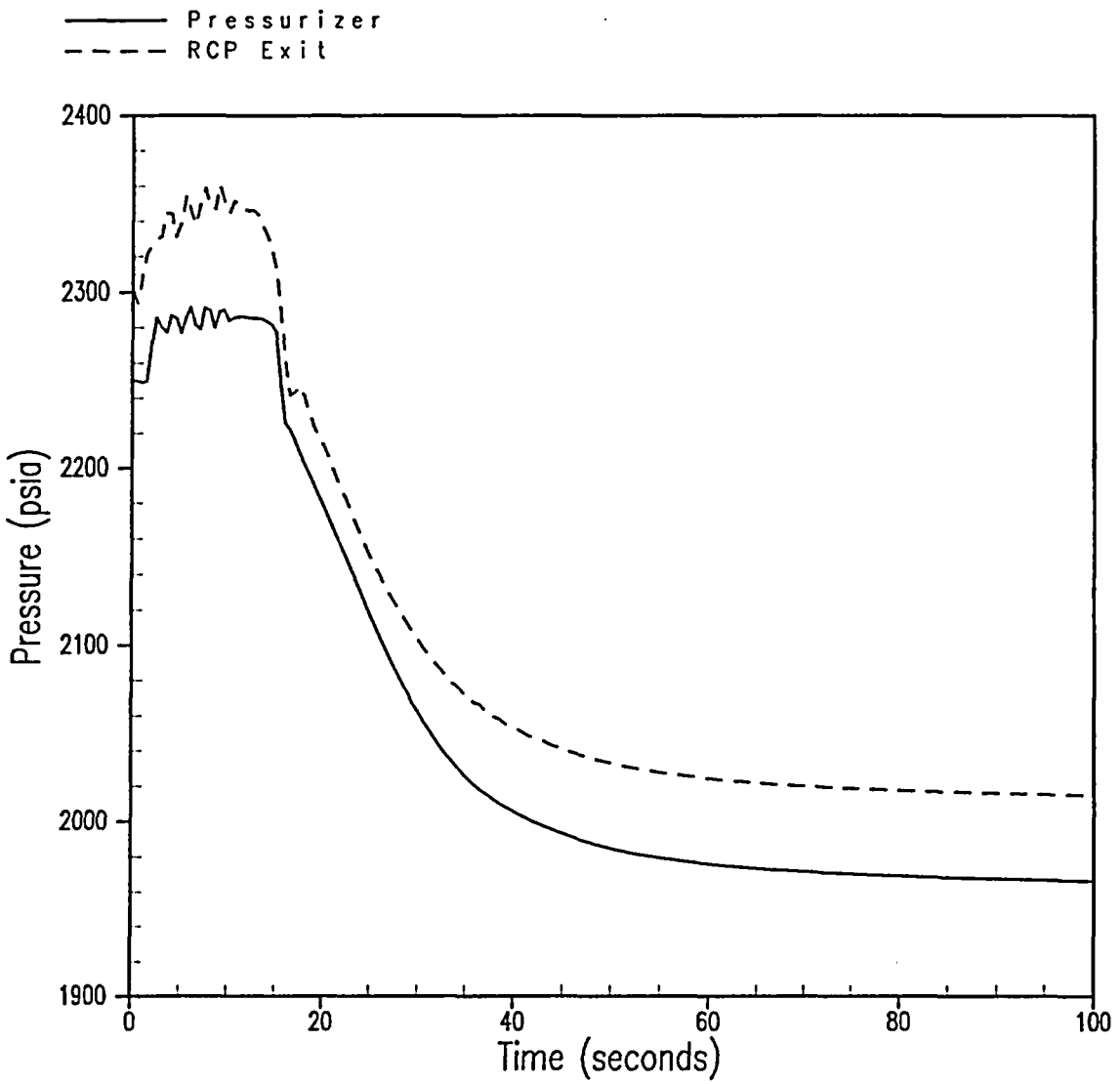


Figure 6.3.3.1-3
Loss of External Electrical Load with Automatic Pressure Control
(Departure from Nucleate Boiling Case)
Pressurizer and Reactor Coolant Pump Exit Pressures versus Time

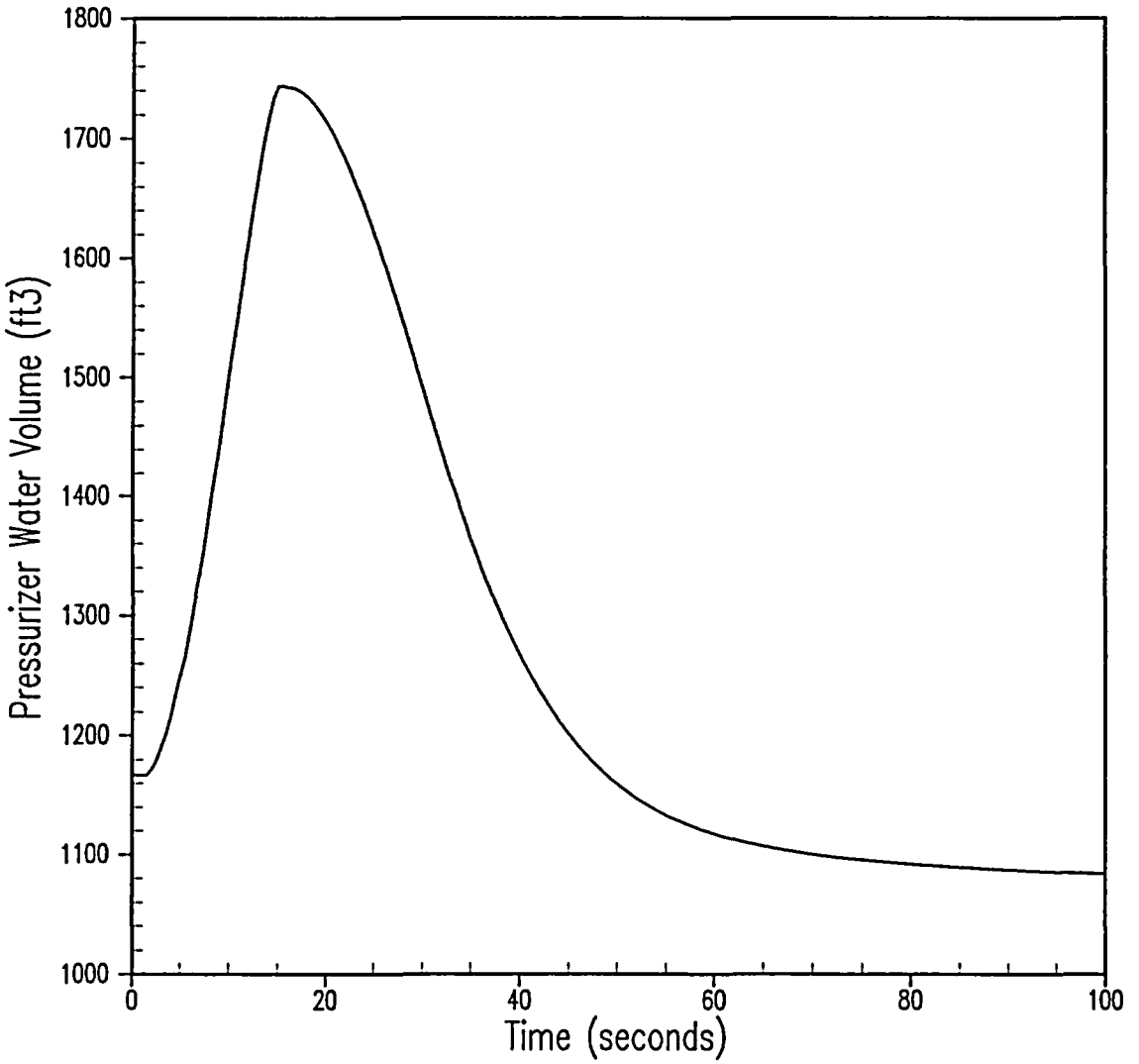


Figure 6.3.3.1-4
Loss of External Electrical Load with Automatic Pressure Control
(Departure from Nucleate Boiling Case)
Pressurizer Water Volume versus Time

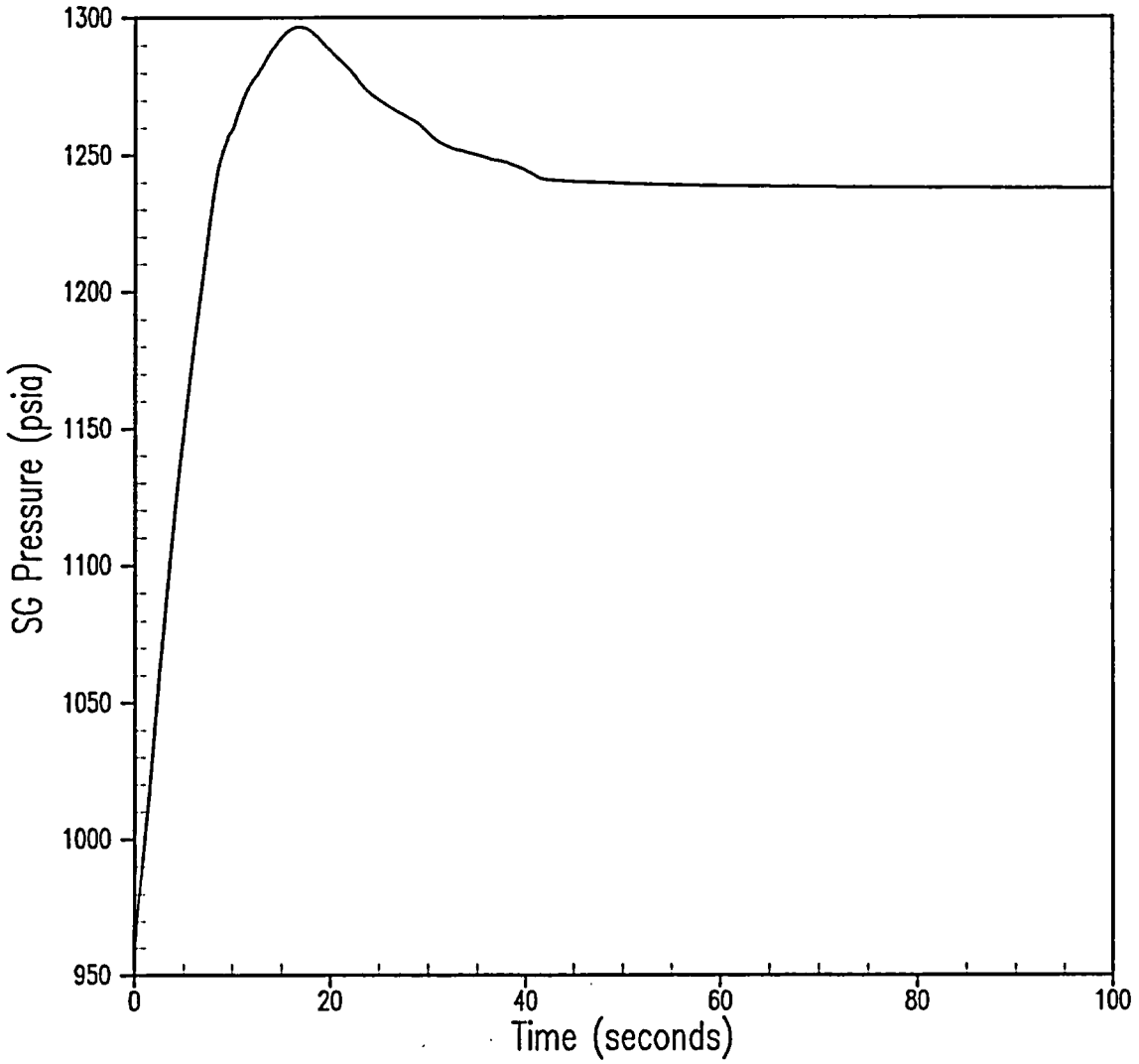


Figure 6.3.3.1-5
Loss of External Electrical Load with Automatic Pressure Control
(Departure from Nucleate Boiling Case)
Steam Generator Pressure versus Time

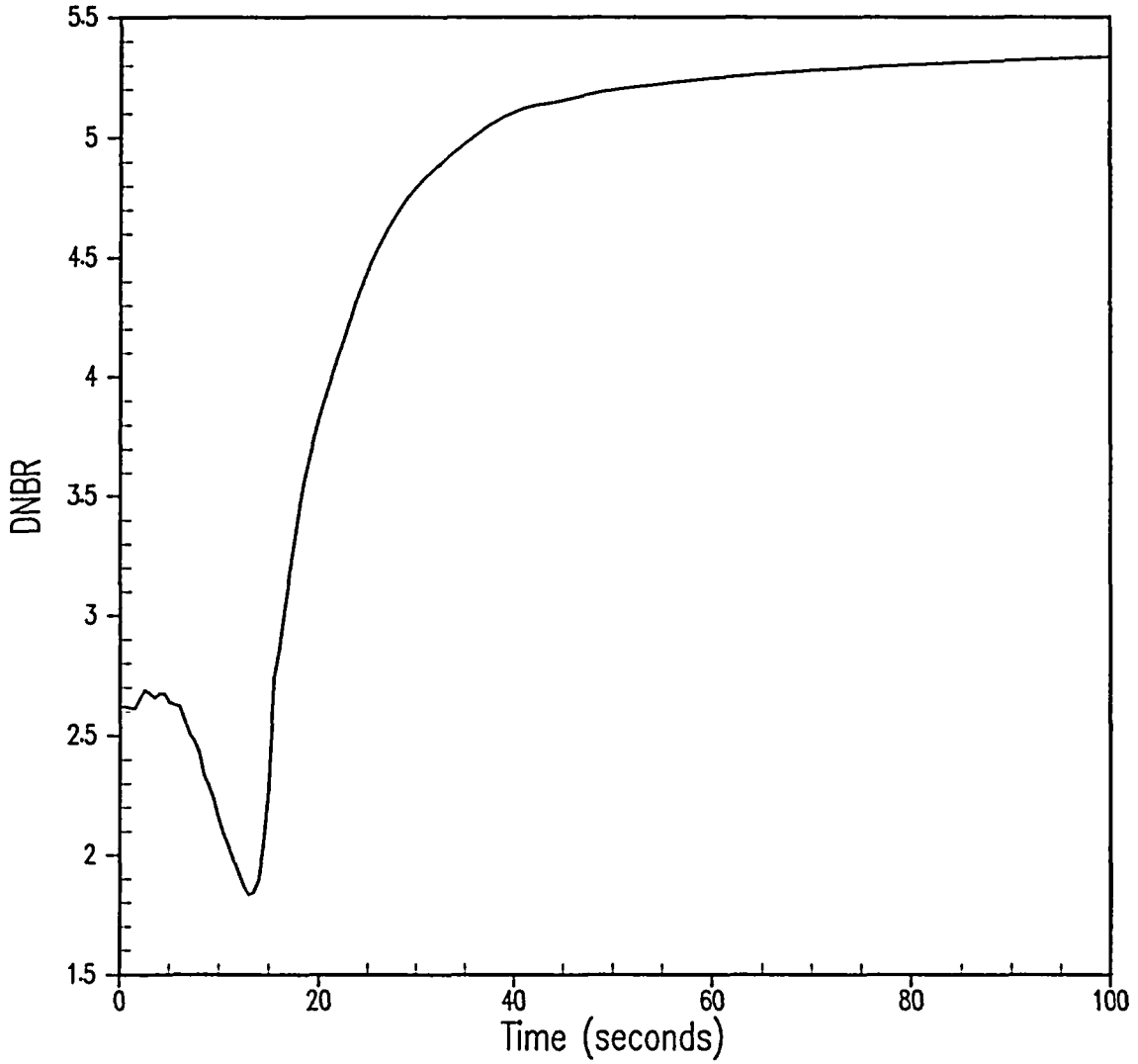


Figure 6.3.3.1-6
Loss of External Electrical Load with Automatic Pressure Control
(Departure from Nucleate Boiling Case)
Departure from Nucleate Boiling Ratio versus Time

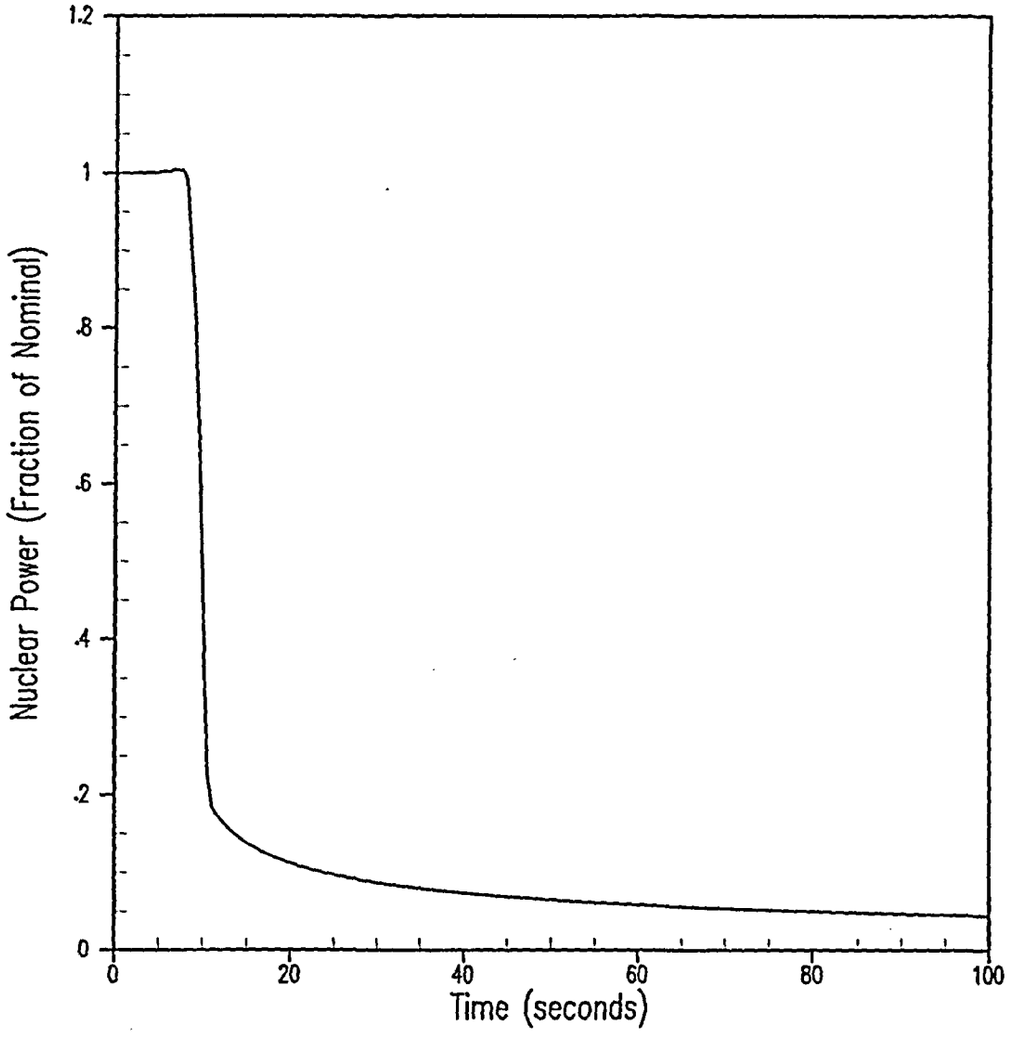


Figure 6.3.3.1-7
Loss of External Electrical Load Without Automatic Pressure Control
(Reactor Coolant System Overpressure Case)
Nuclear Power versus Time

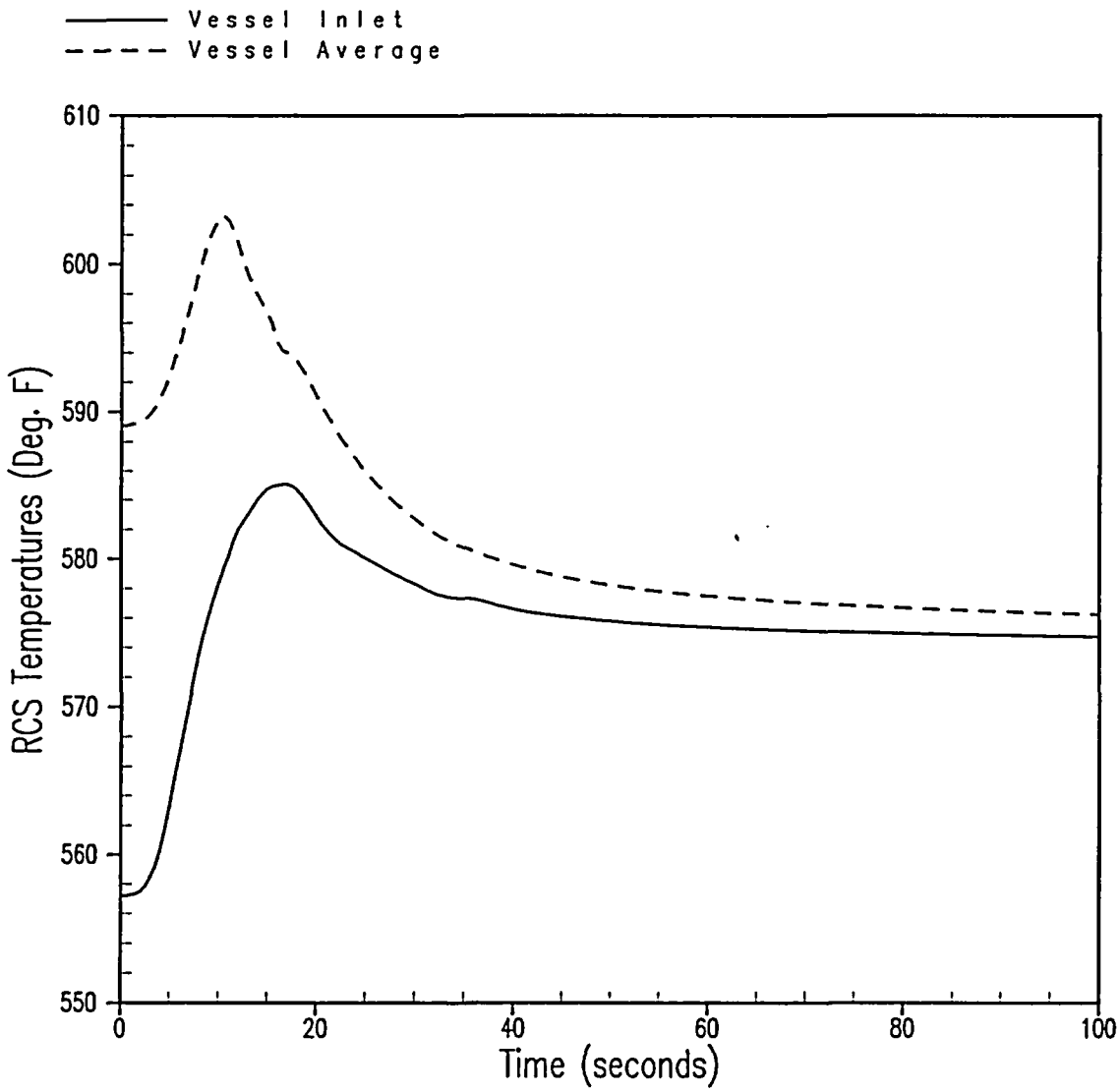


Figure 6.3.3.1-8
Loss of External Electrical Load Without Automatic Pressure Control
(Reactor Coolant System Overpressure Case)
Vessel Average and Inlet Temperatures versus Time

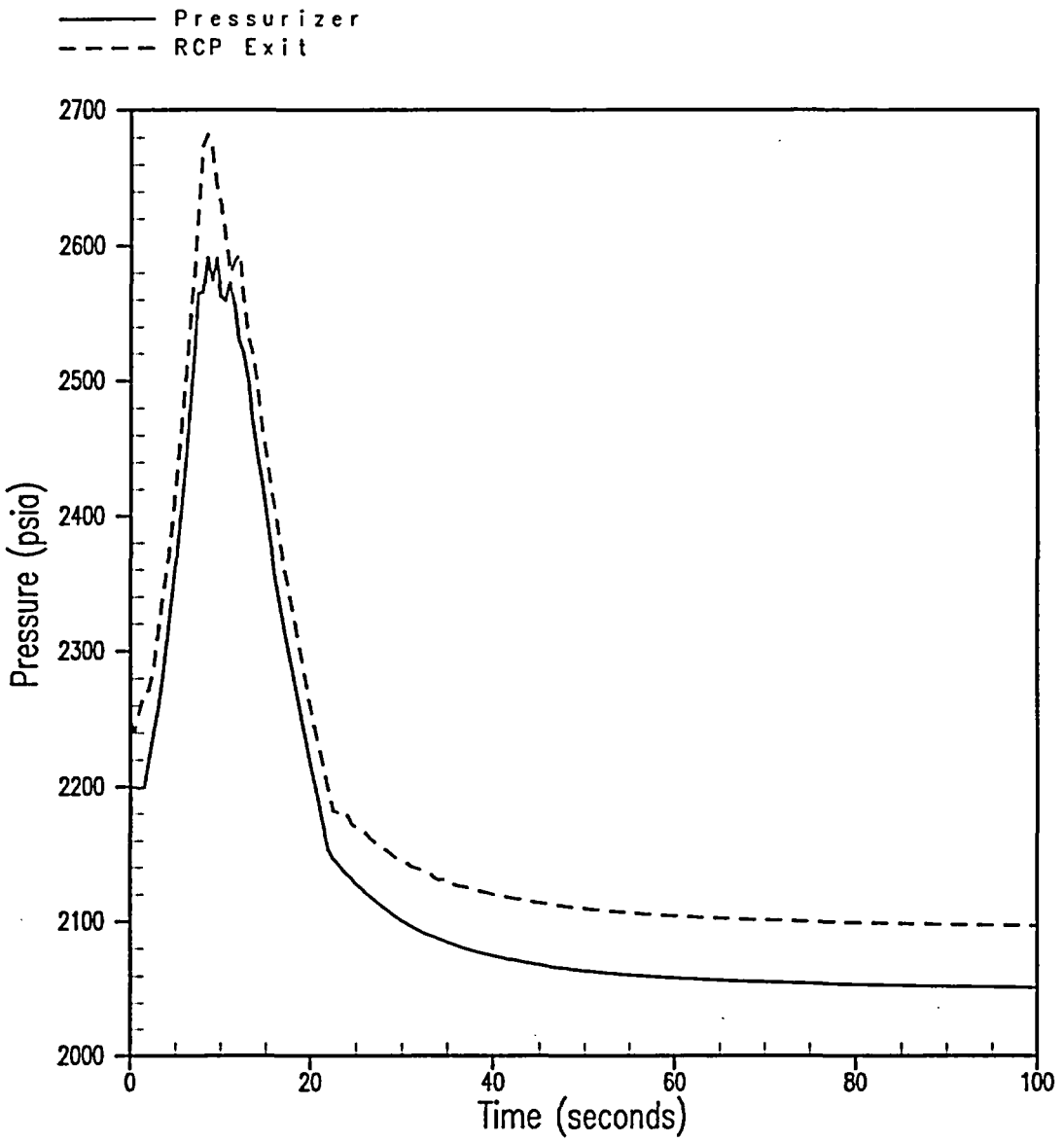


Figure 6.3.3.1-9
Loss of External Electrical Load Without Automatic Pressure Control
(Reactor Coolant System Overpressure Case)
Pressurizer and Reactor Coolant Pump Exit Pressures versus Time

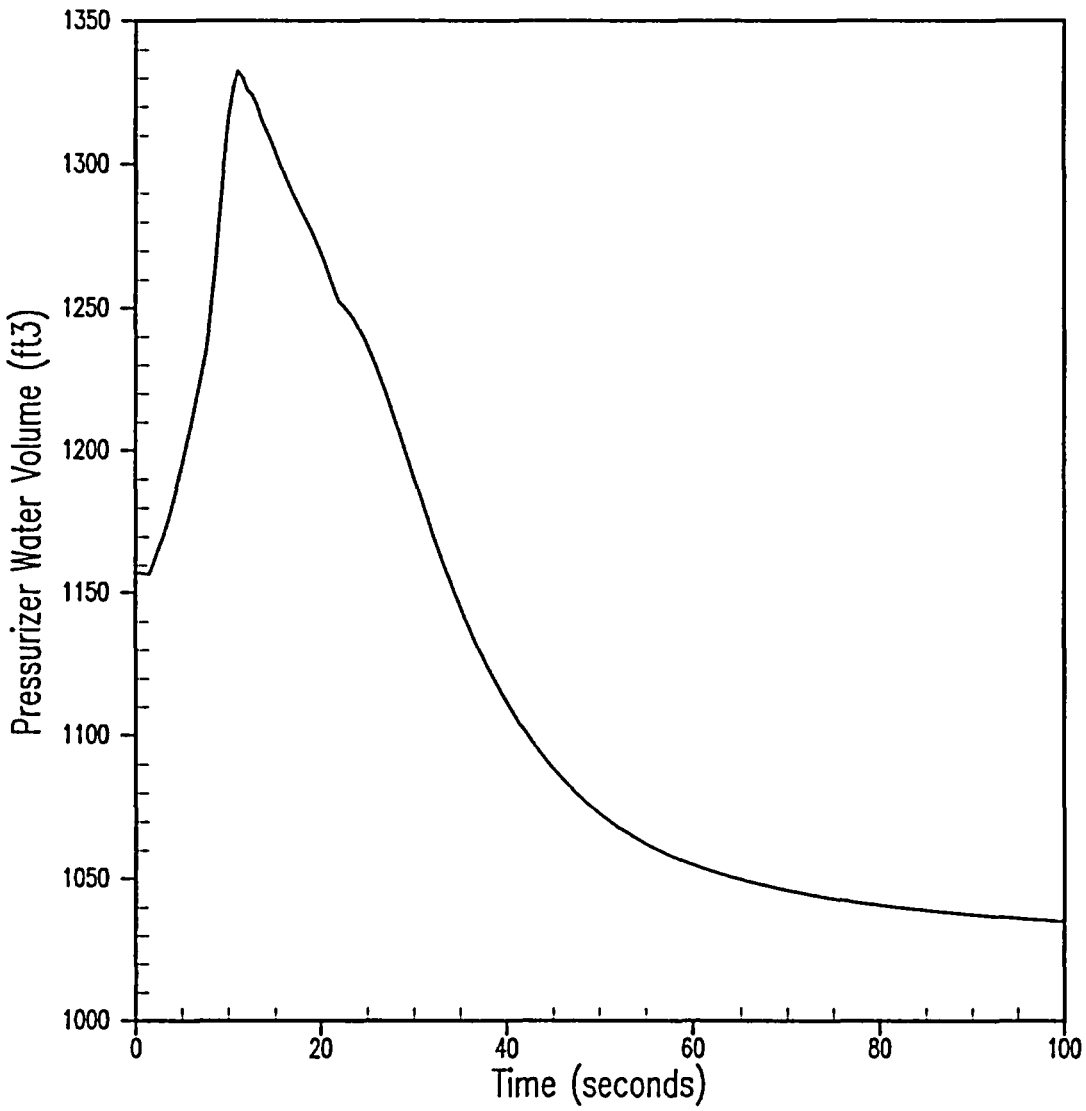


Figure 6.3.3.1-10
Loss of External Electrical Load Without Automatic Pressure Control
(Reactor Coolant System Overpressure Case)
Pressurizer Water Volume versus Time

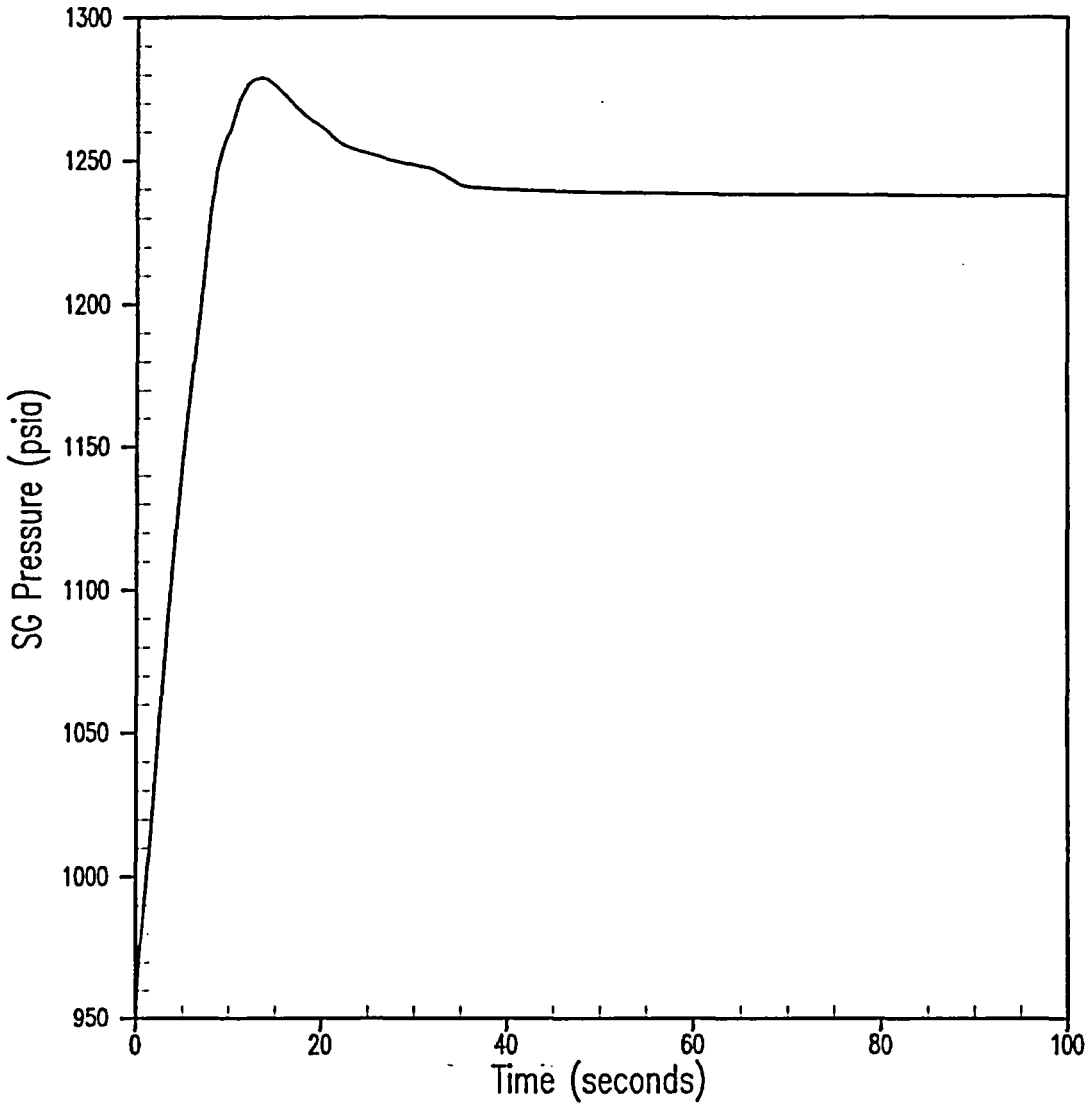


Figure 6.3.3.1-11
Loss of External Electrical Load Without Automatic Pressure Control
(Reactor Coolant System Overpressure Case)
Steam Generator Pressure versus Time

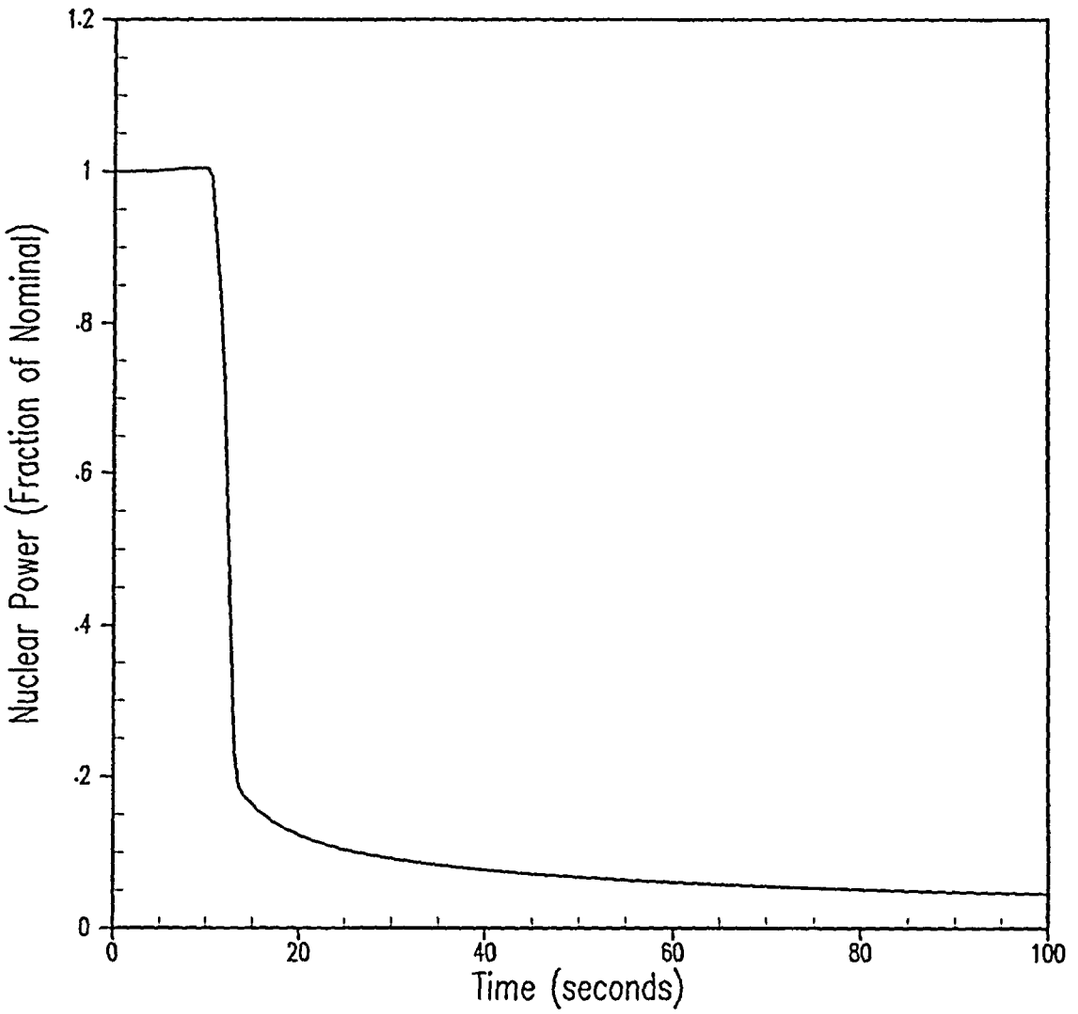


Figure 6.3.3.1-12
Loss of External Electrical Load with Automatic Pressure Control
(Main Steam System Overpressure Case)
Nuclear Power versus Time

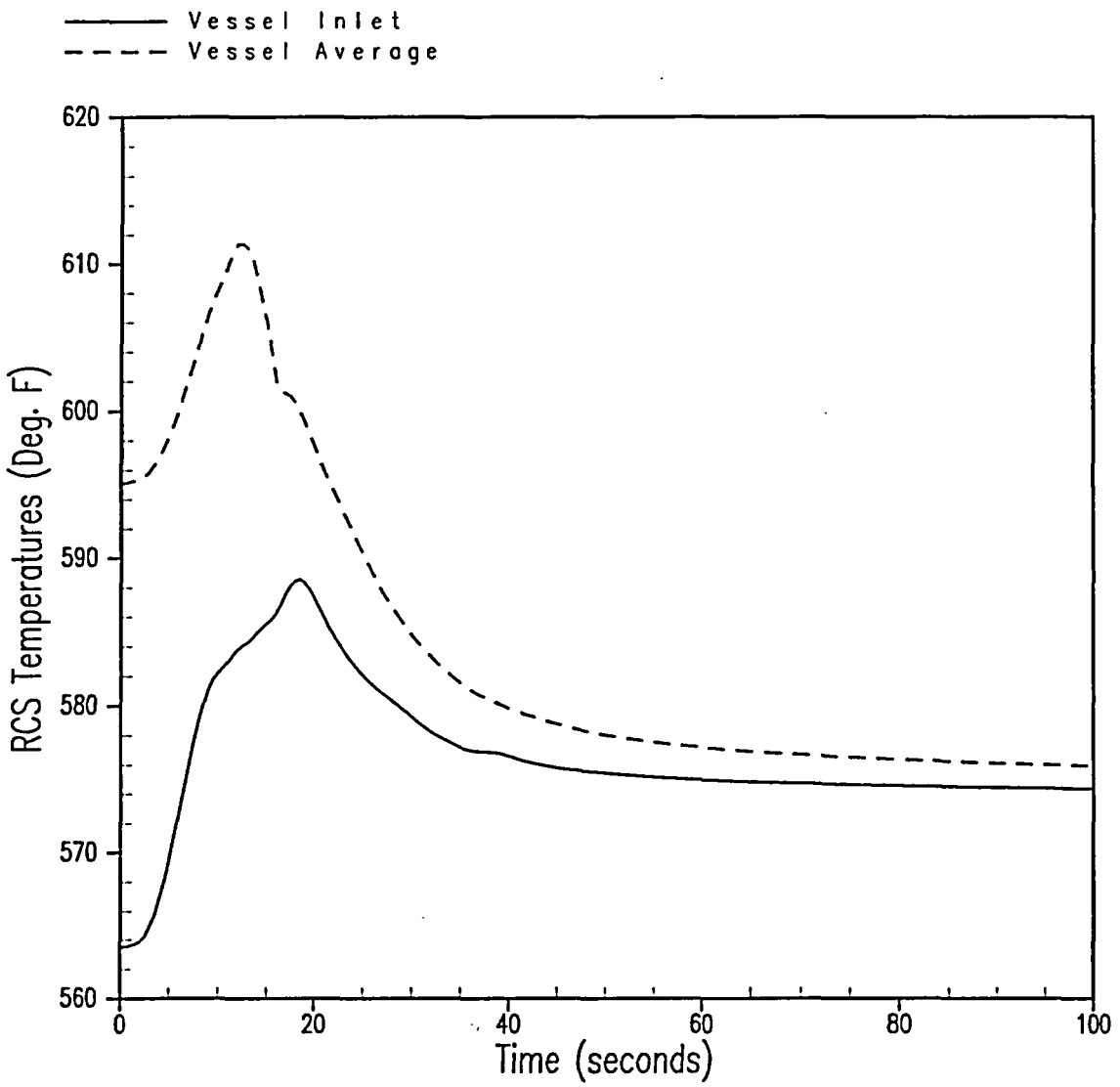


Figure 6.3.3.1-13
Loss of External Electrical Load with Automatic Pressure Control
(Main Steam System Overpressure Case)
Vessel Average and Inlet Temperatures versus Time

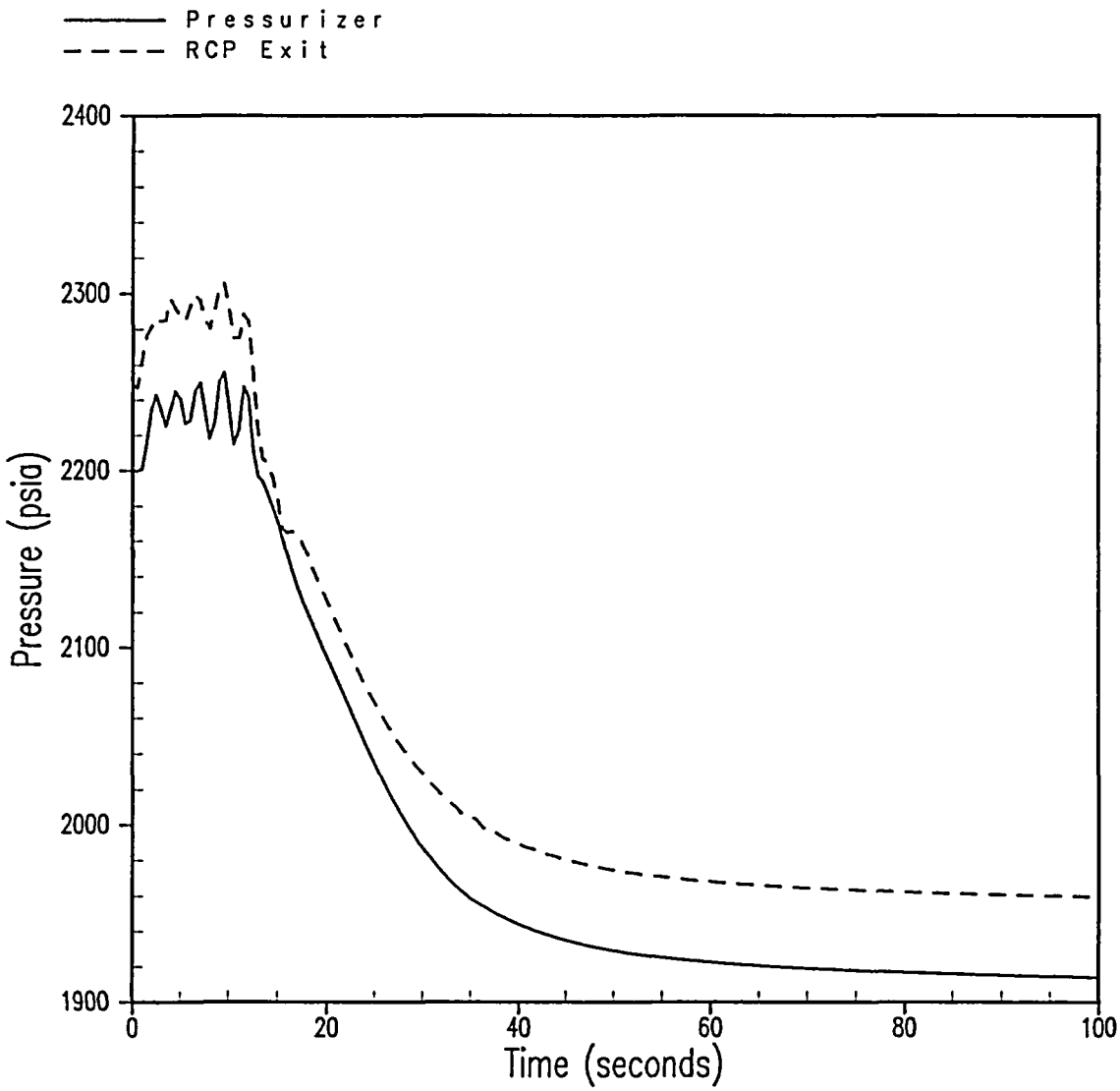


Figure 6.3.3.1-14
Loss of External Electrical Load with Automatic Pressure Control
(Main Steam System Overpressure Case)
Pressurizer and Reactor Coolant Pump Exit Pressures versus Time

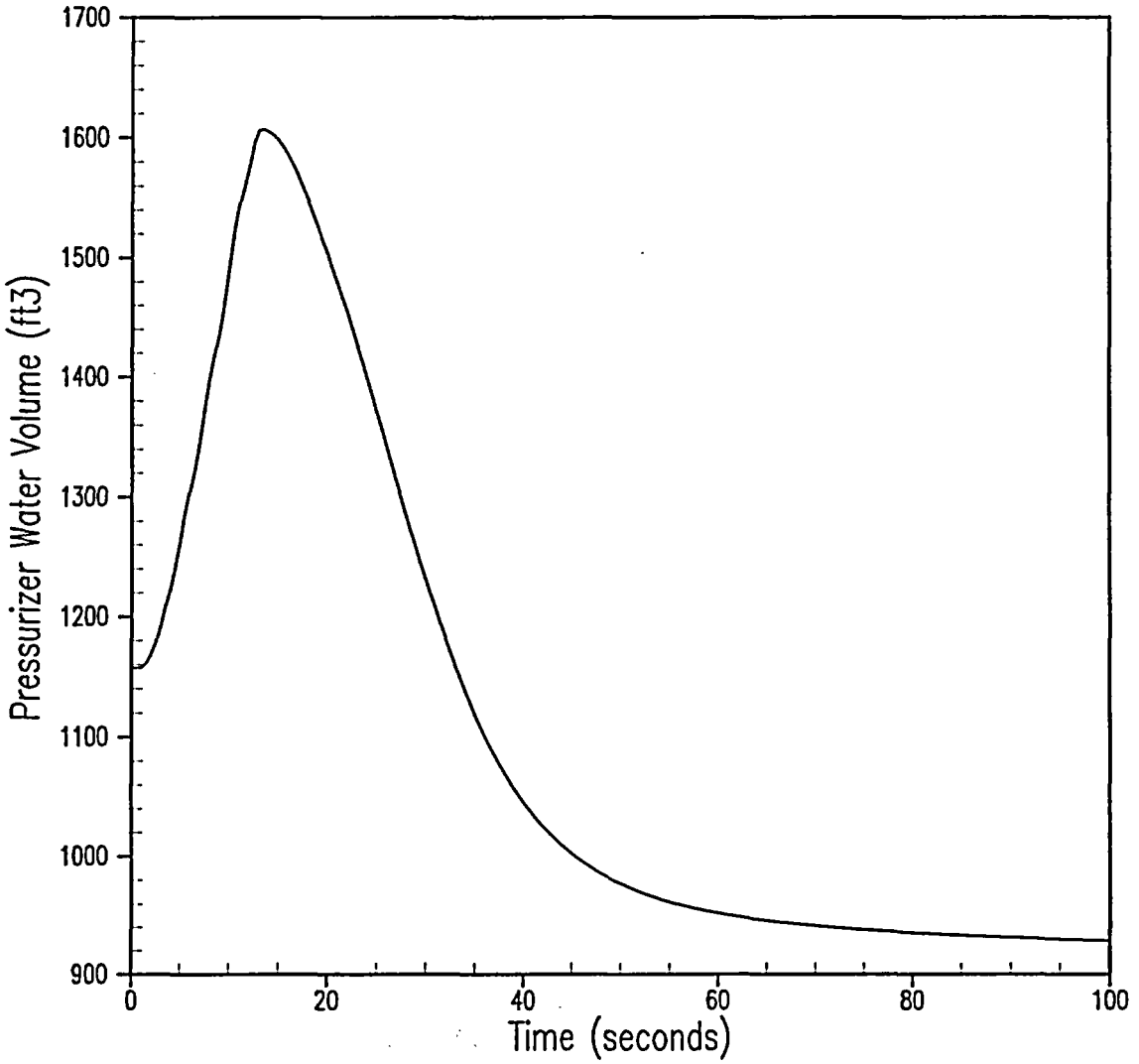


Figure 6.3.3.1-15
Loss of External Electrical Load with Automatic Pressure Control
(Main Steam System Overpressure Case)
Pressurizer Water Volume versus Time

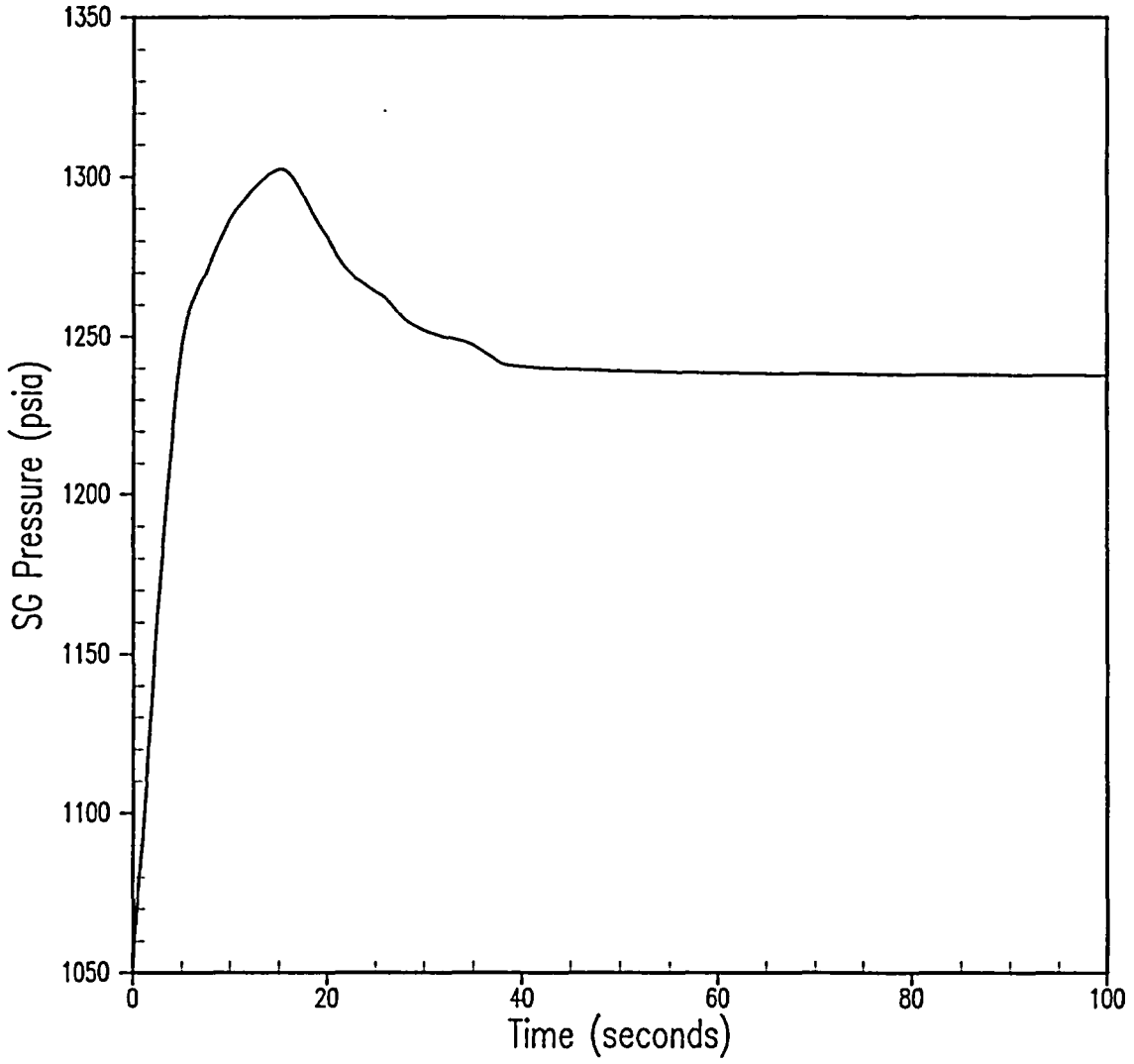


Figure 6.3.3.1-16
Loss of External Electrical Load with Automatic Pressure Control
(Main Steam System Overpressure Case)
Steam Generator Pressure versus Time

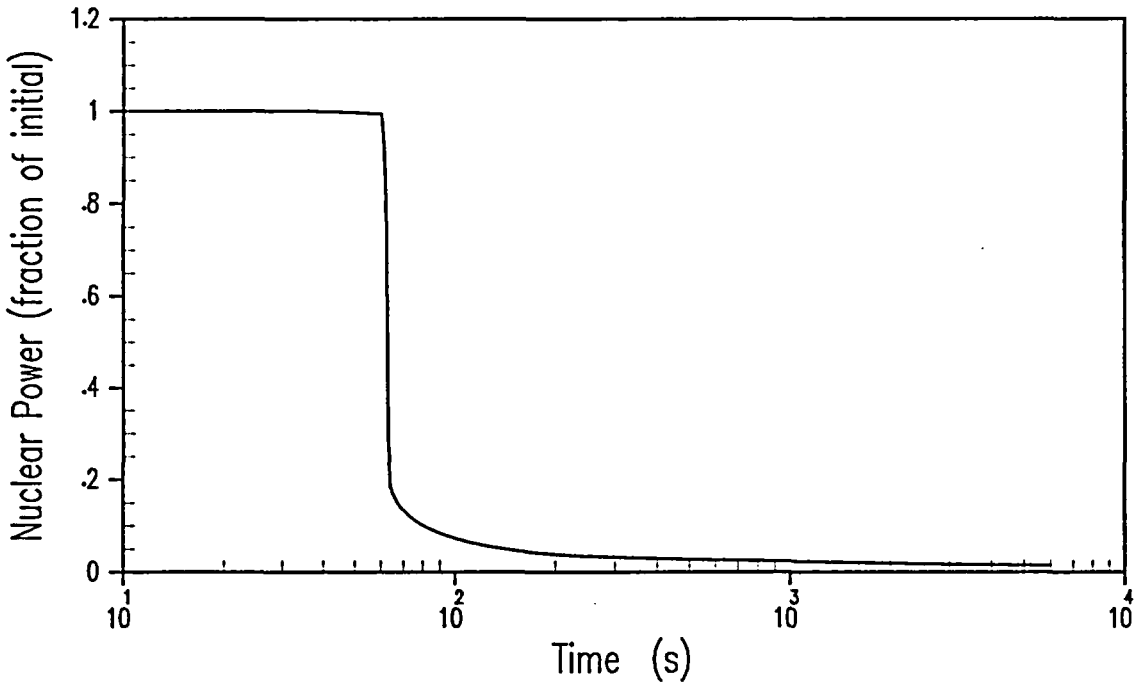


Figure 6.3.3.2-1
Loss of Normal Feedwater
Nuclear Power

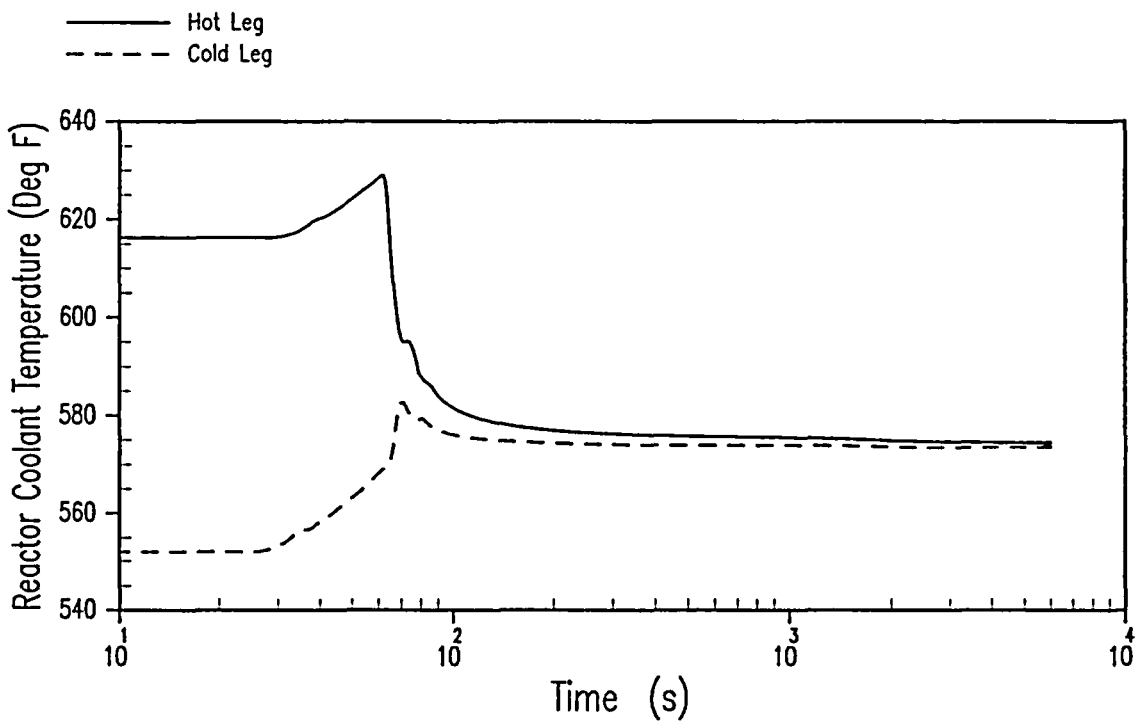


Figure 6.3.3.2-2
Loss of Normal Feedwater
Reactor Coolant Temperatures

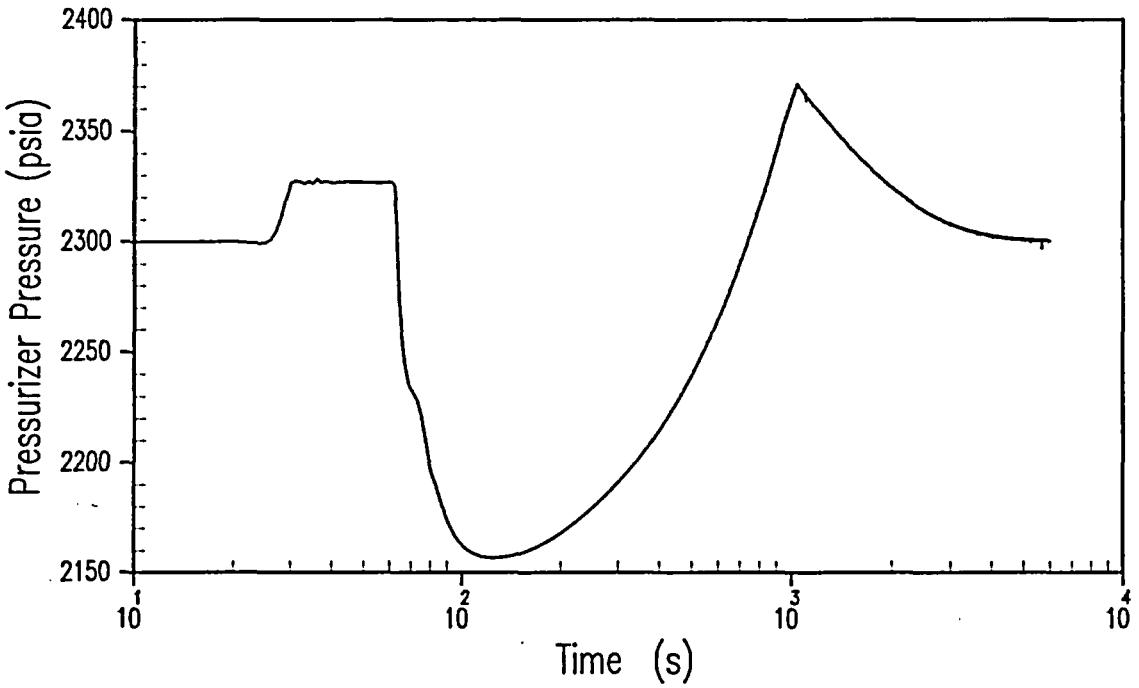


Figure 6.3.3.2-3
Loss of Normal Feedwater
Pressurizer Pressure

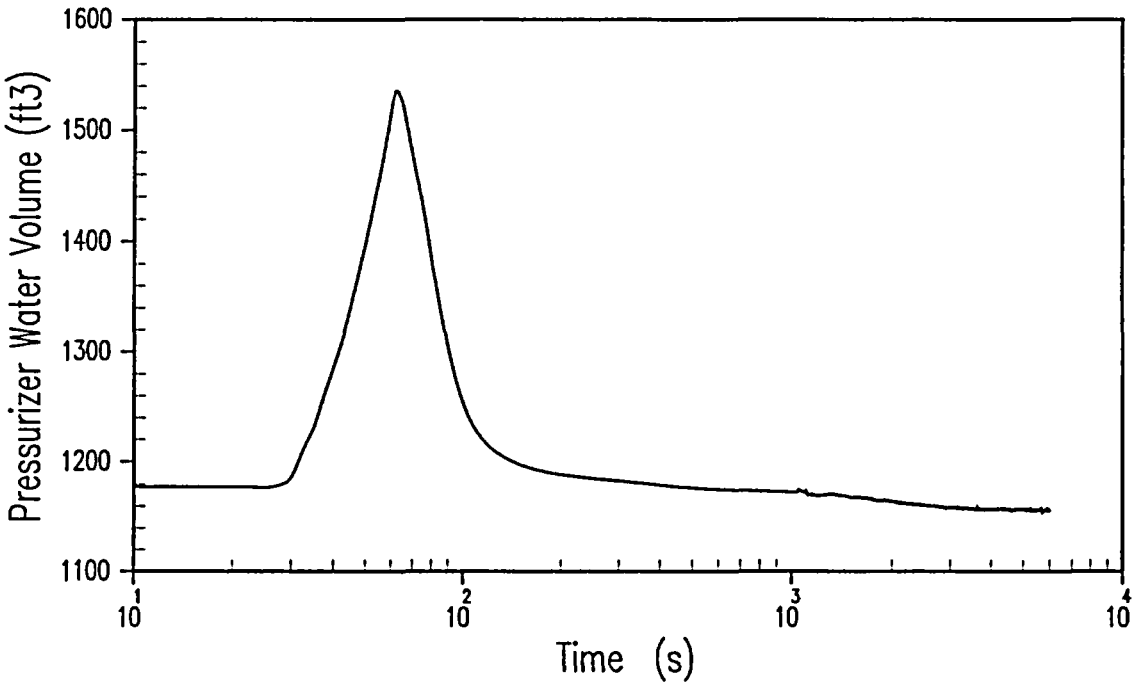


Figure 6.3.3.2-4
Loss of Normal Feedwater
Pressurizer Water Volume

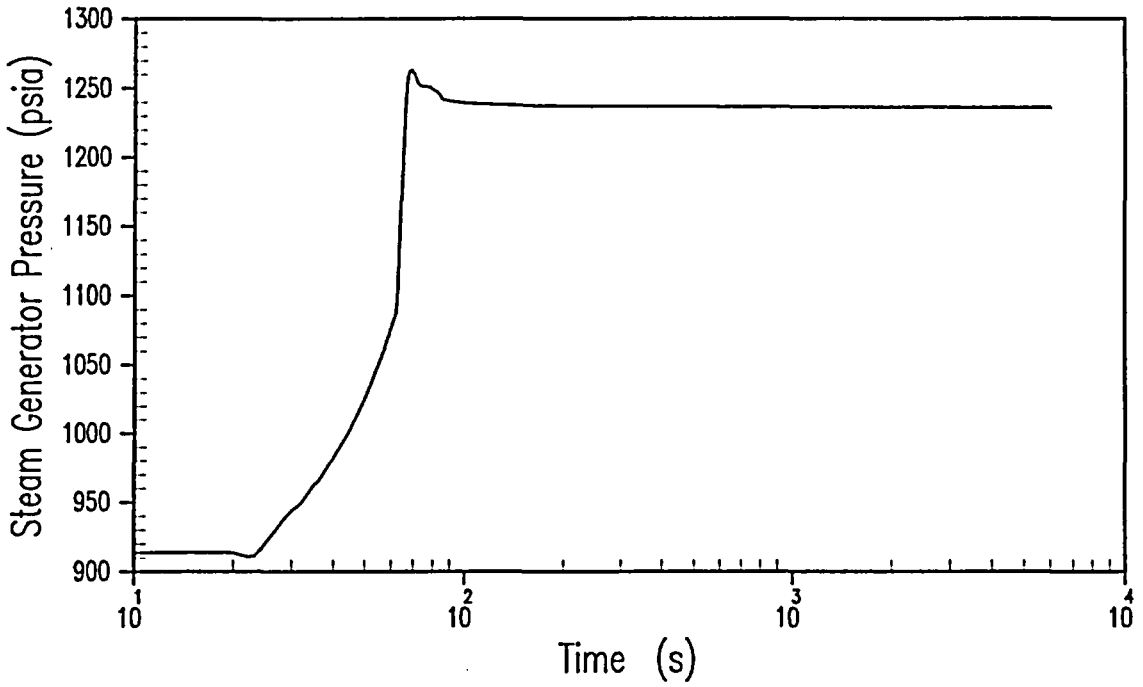


Figure 6.3.3.2-5
Loss of Normal Feedwater
Steam Generator Pressure

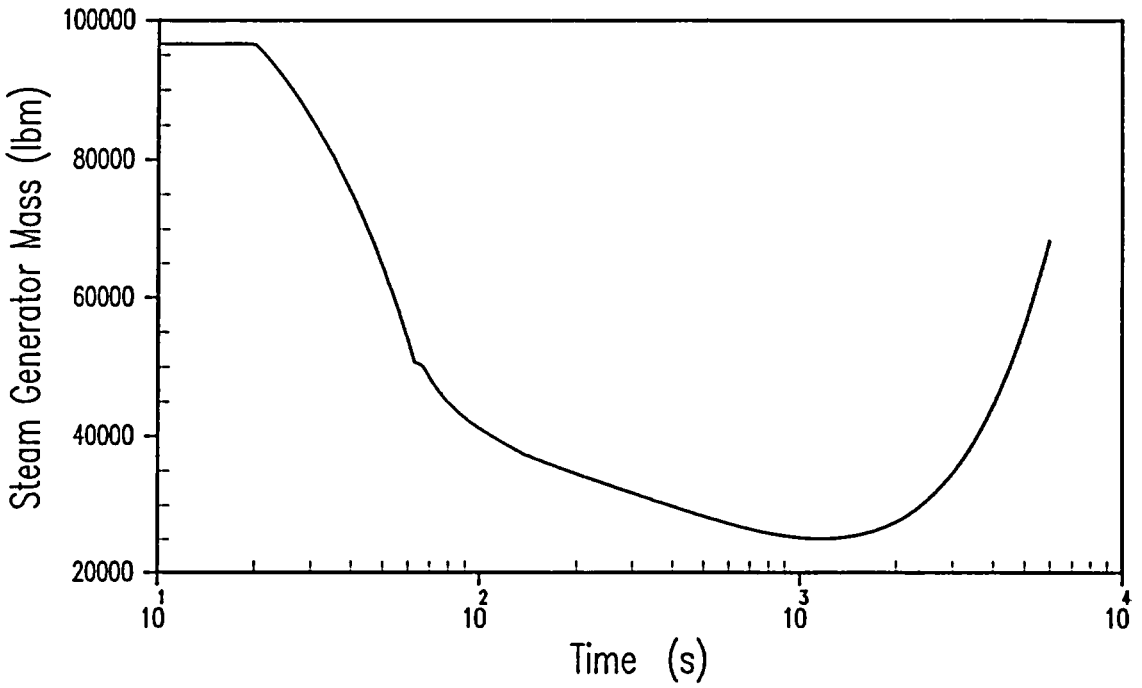


Figure 6.3.3.2-6
Loss of Normal Feedwater
Steam Generator Mass

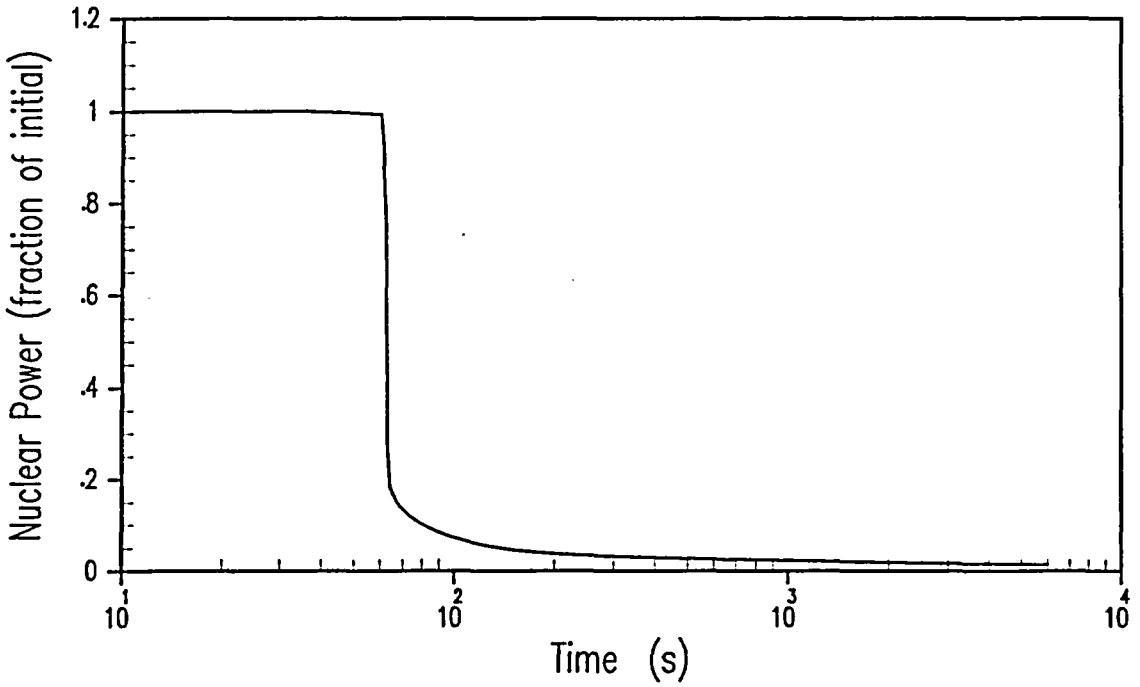


Figure 6.3.3.3-1
Loss of Nonemergency AC Power to the Plant Auxiliaries
Nuclear Power

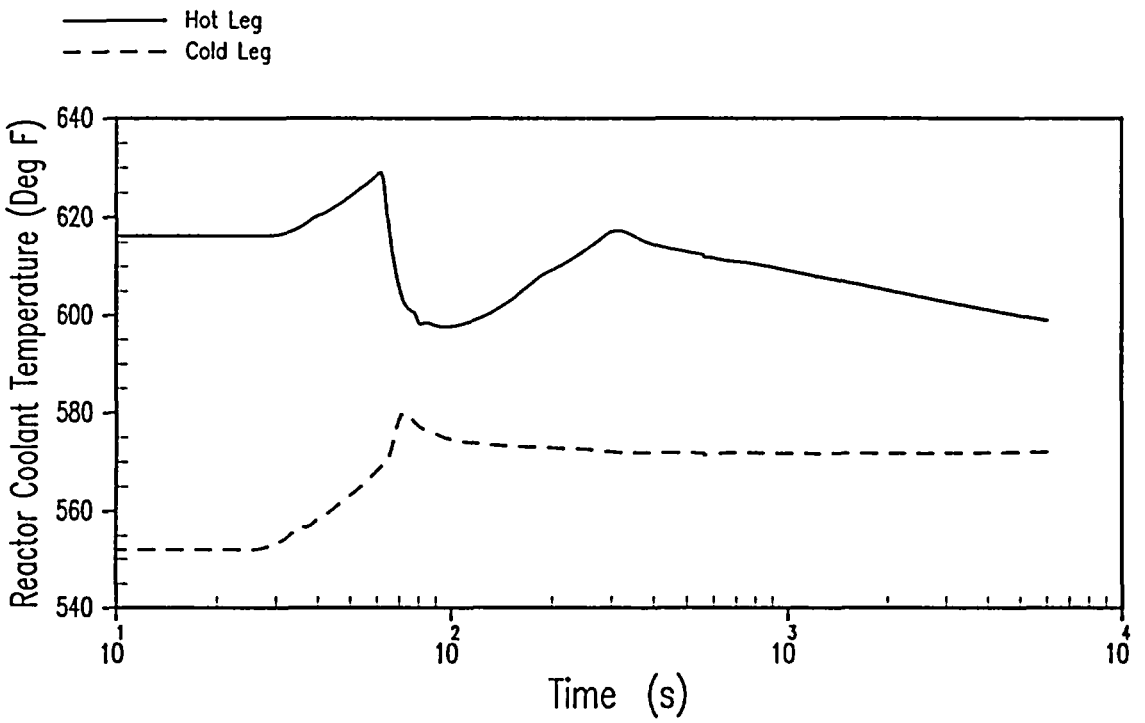


Figure 6.3.3.3-2
Loss of Nonemergency AC Power to the Plant Auxiliaries
Reactor Coolant Temperatures

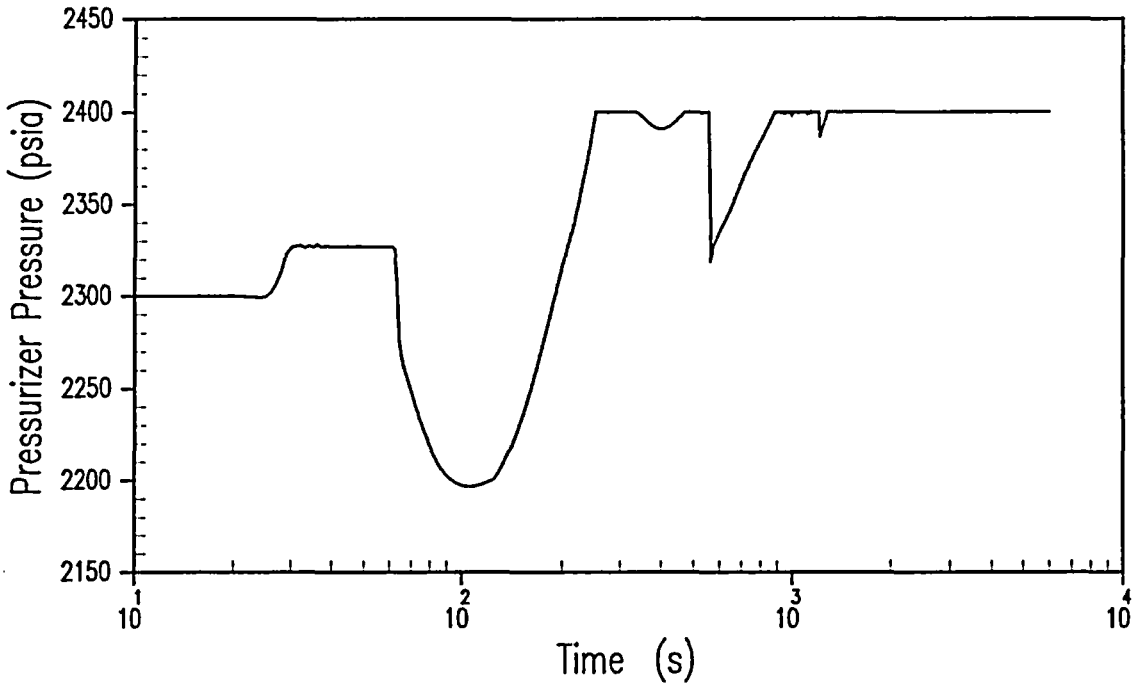


Figure 6.3.3.3-3
Loss of Nonemergency AC Power to the Plant Auxiliaries
Pressurizer Pressure

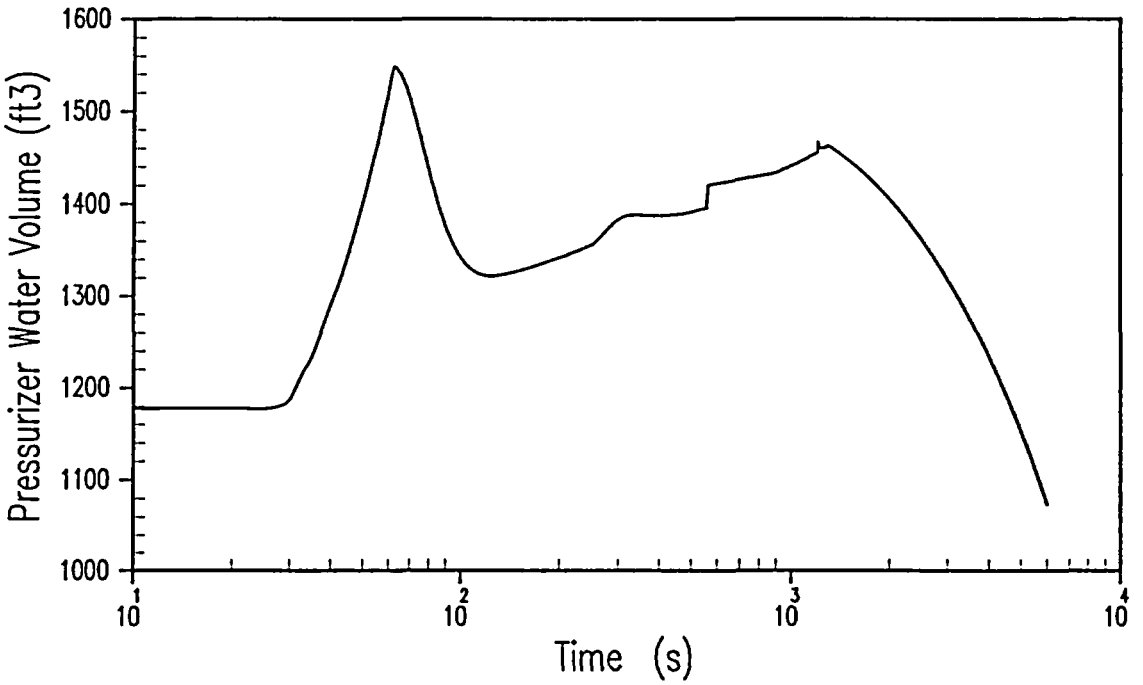


Figure 6.3.3.3-4
Loss of Nonemergency AC Power to the Plant Auxiliaries
Pressurizer Water Volume

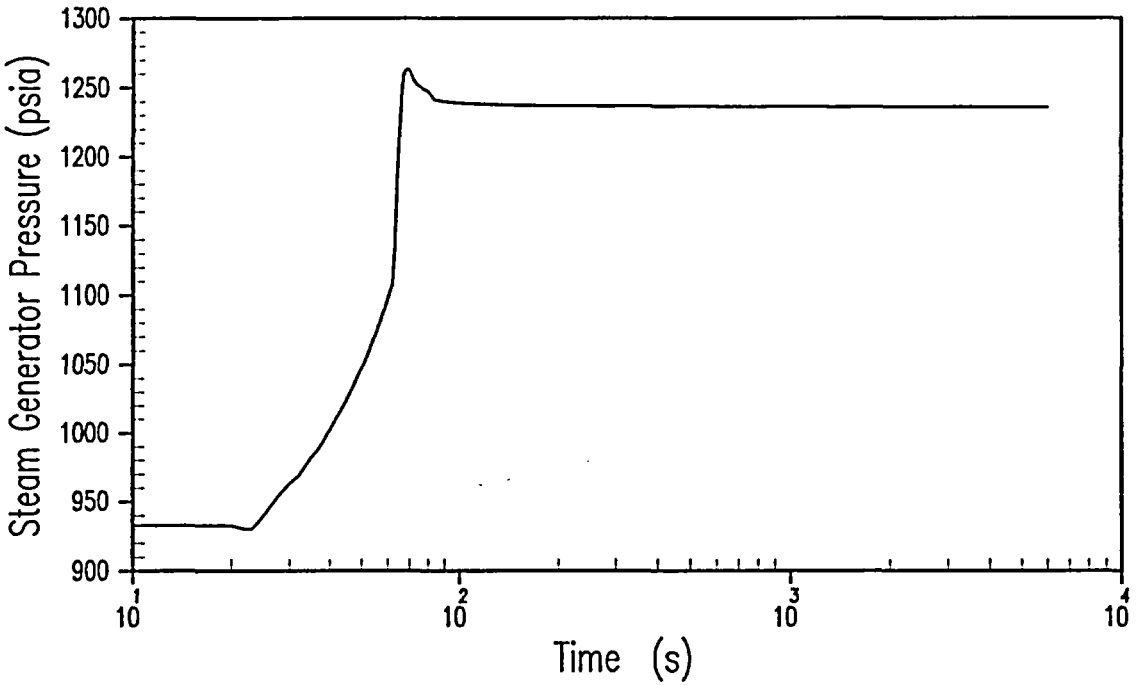


Figure 6.3.3.3-5
Loss of Nonemergency AC Power to the Plant Auxiliaries
Steam Generator Pressure

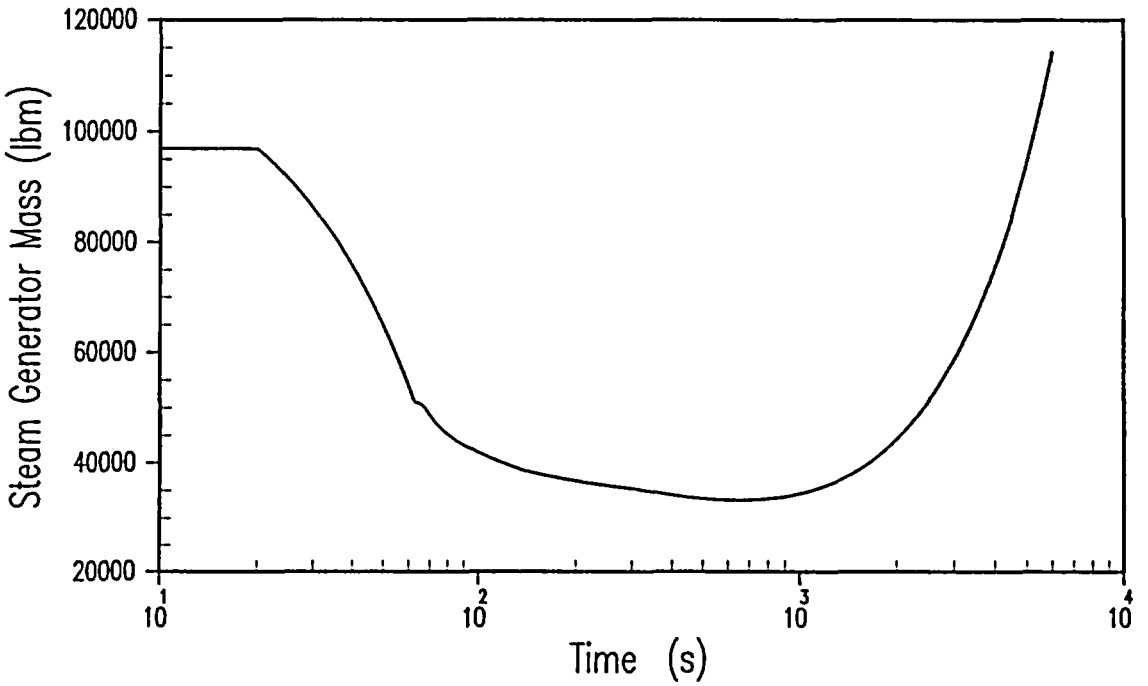
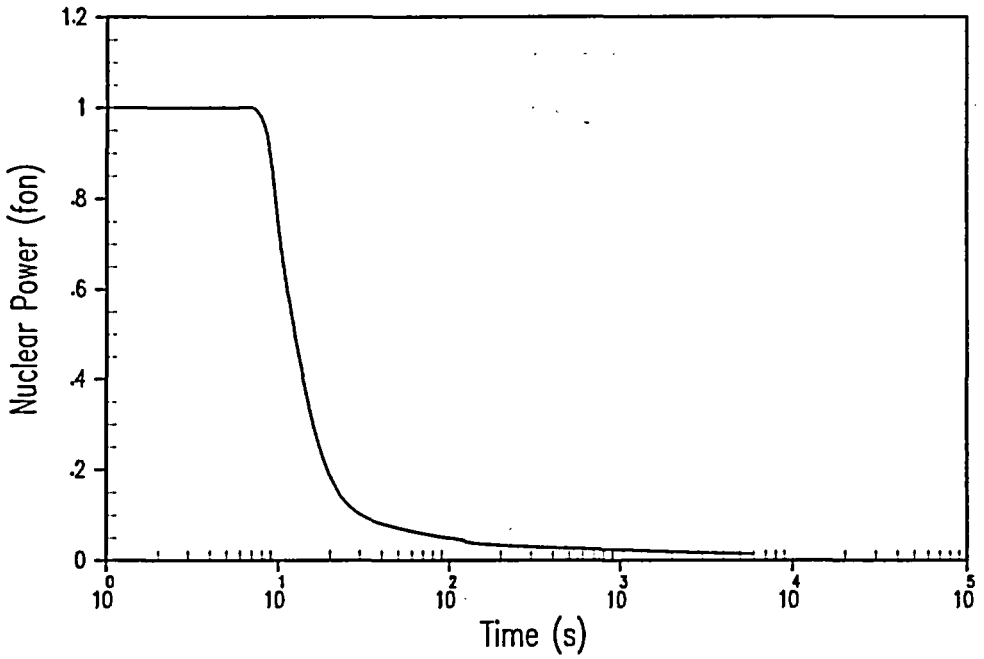


Figure 6.3.3.3-6
Loss of Nonemergency AC Power to the Plant Auxillaries
Steam Generator Mass



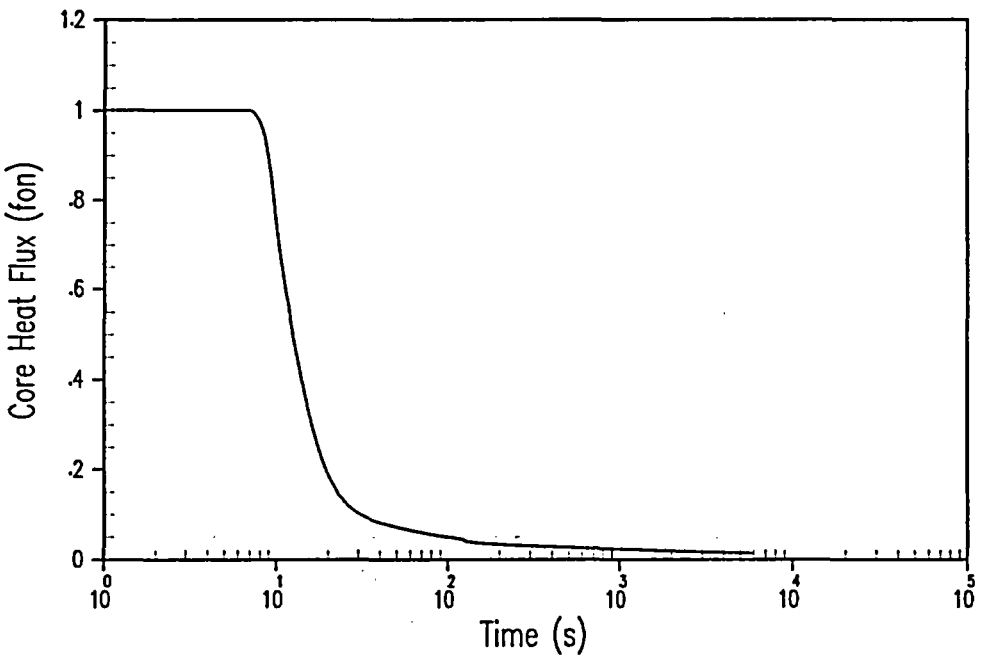
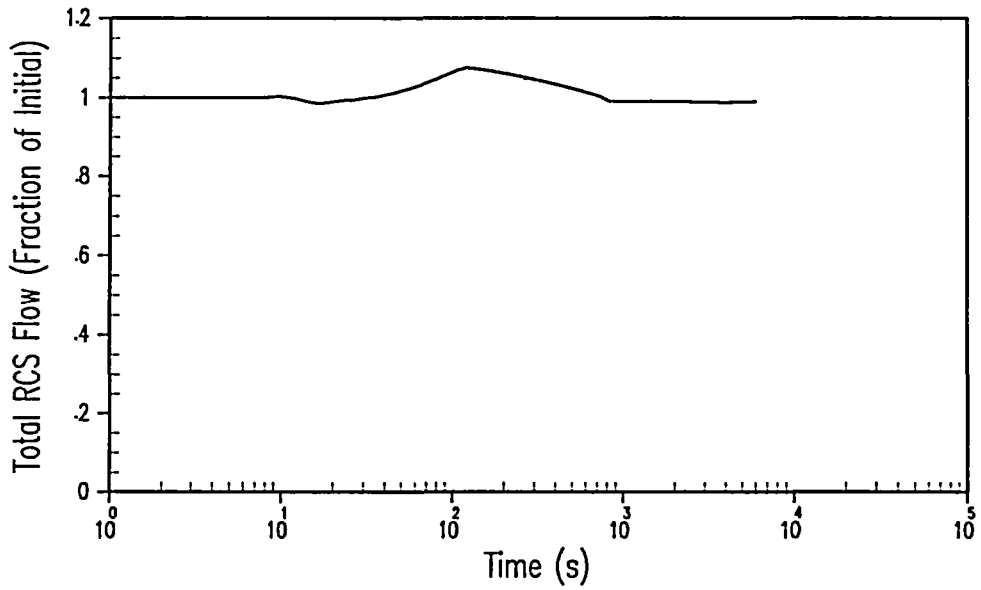


Figure 6.3.3.4-1
Feedline Break Accident
Nuclear Power and Core Heat Flux versus Time



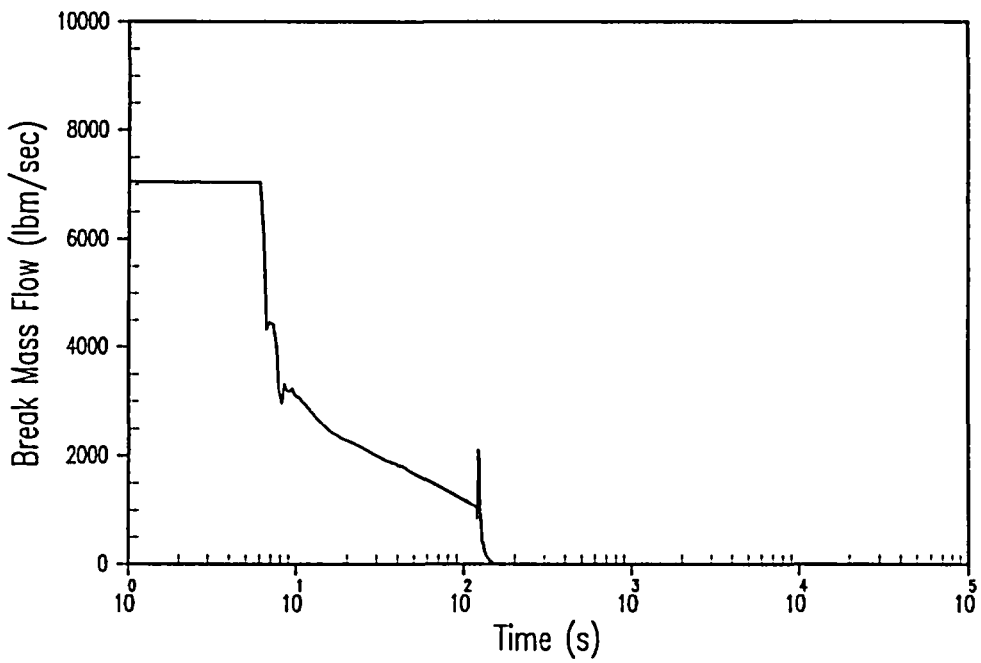
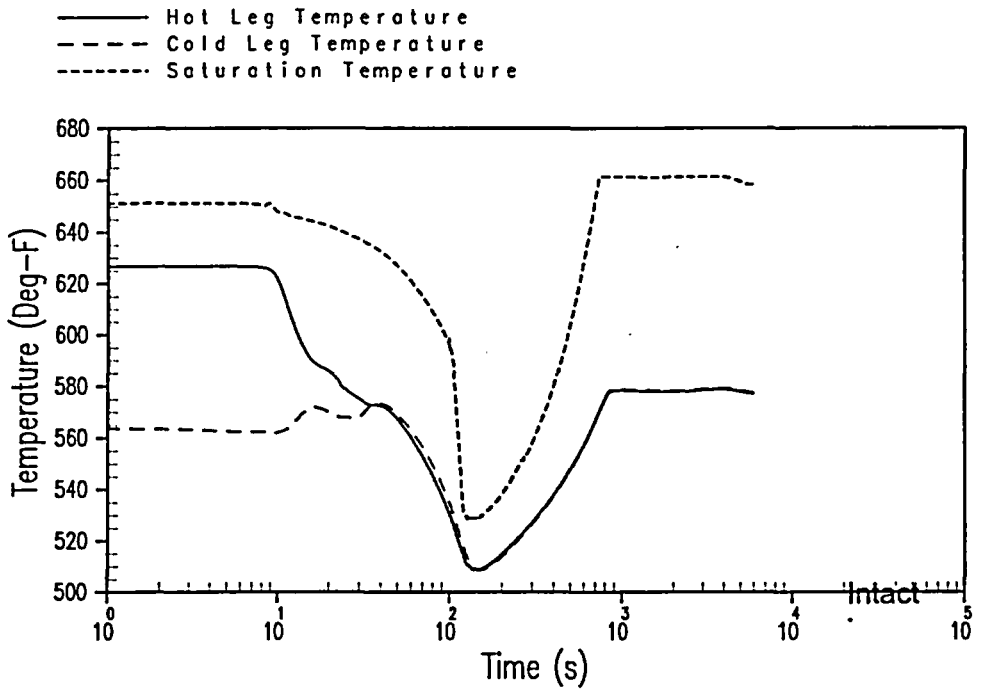


Figure 6.3.3.4-2
Feedline Break Accident
Reactor Coolant System Flow and Feedline Break Flow versus Time



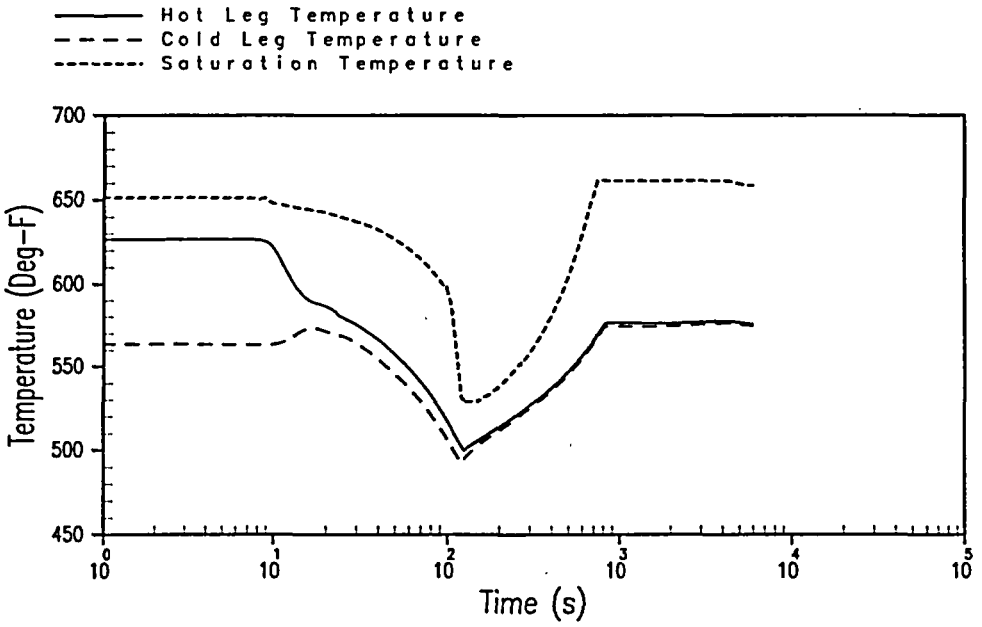
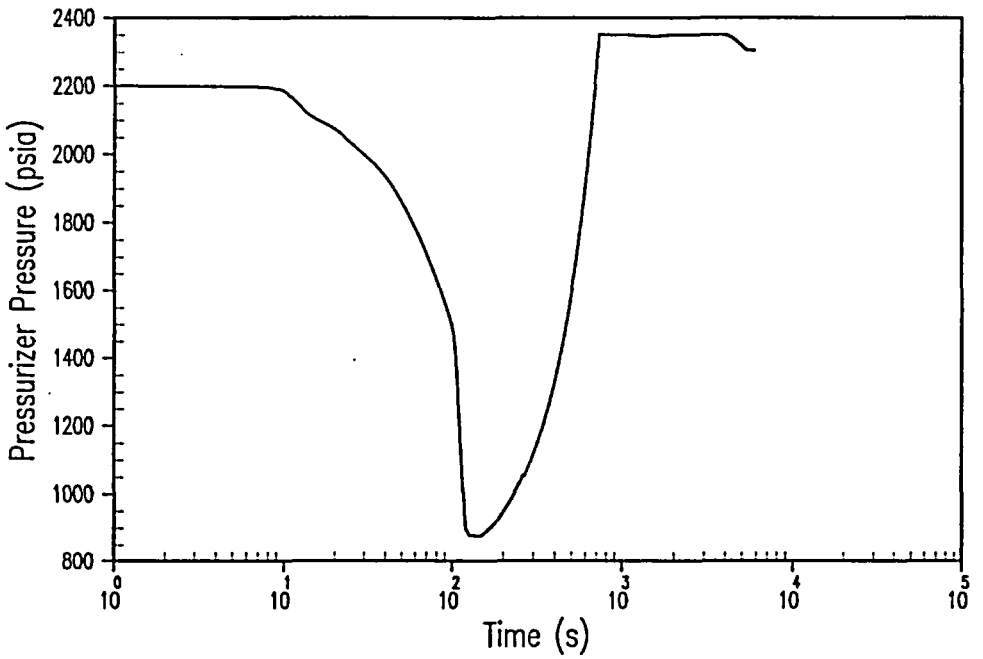


Figure 6.3.3.4-3
Feedline Break Accident
Loop 1 (faulted) and Loop 2 (intact) Hot Leg and Saturation Temperatures versus Time



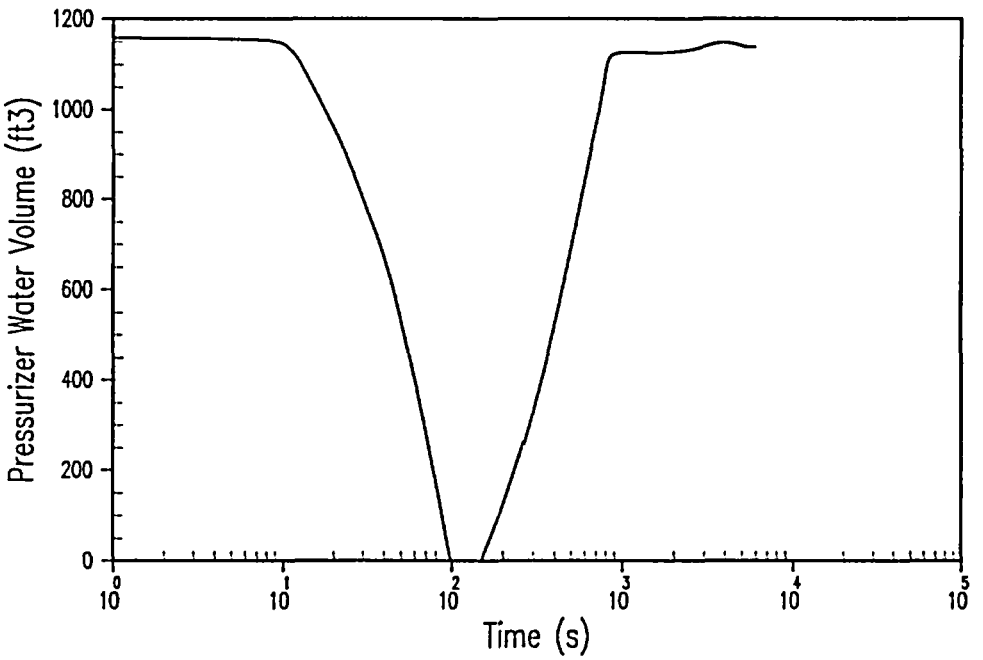
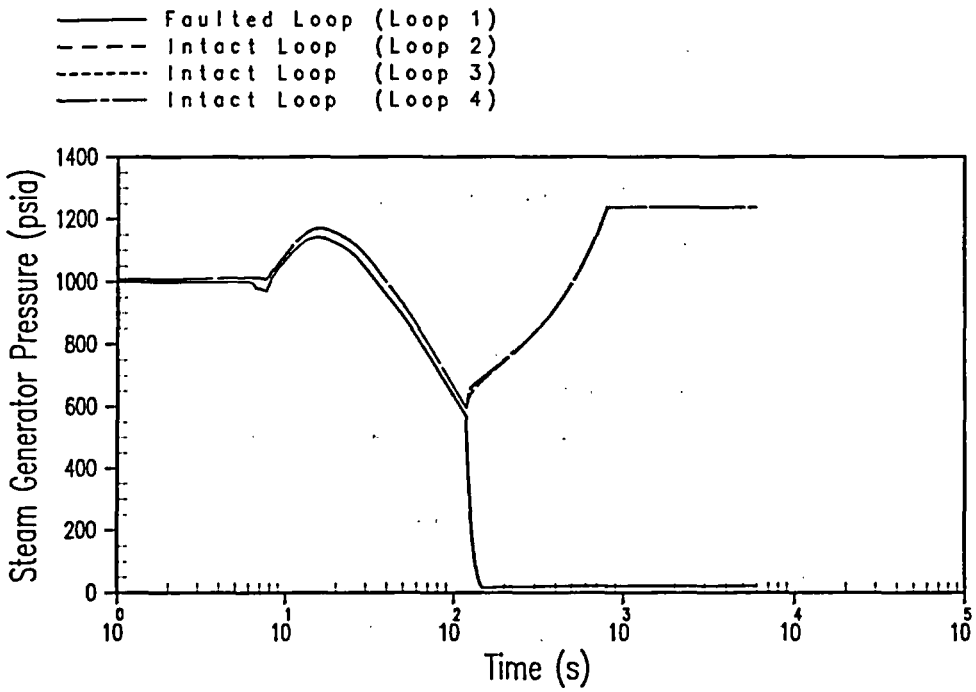


Figure 6.3.3.4-4
Feedline Break Accident
Pressurizer Pressure and Pressurizer Water Volume versus Time



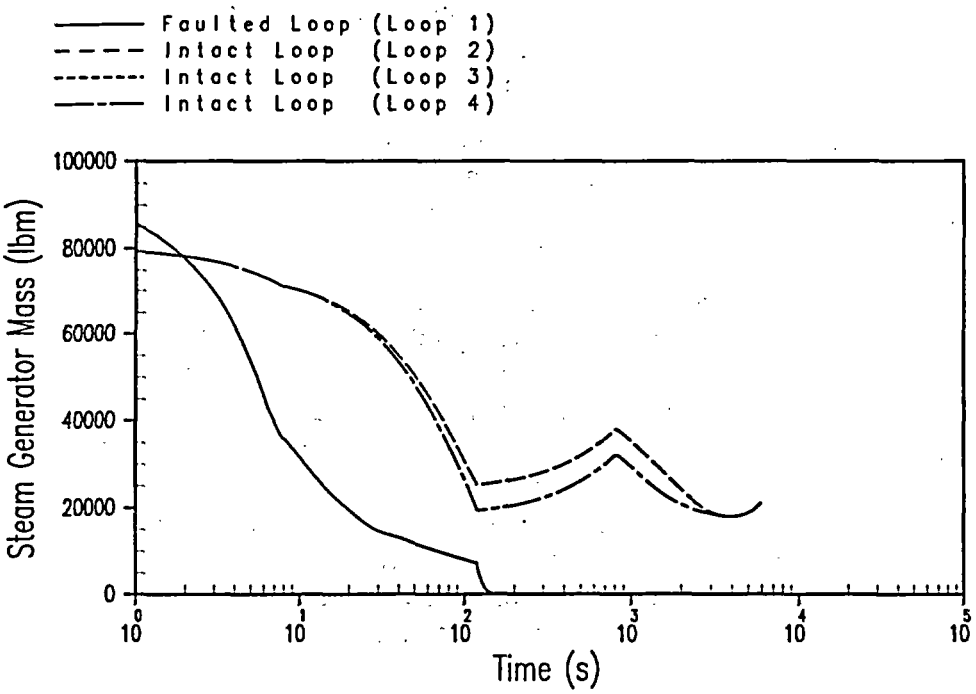


Figure 6.3.3.4-5
Feedline Break Accident
Steam Generator Pressure and Secondary Side Steam Generator Mass versus Time

6.3.4 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

6.3.4.1 PARTIAL LOSS OF REACTOR COOLANT FLOW / COMPLETE LOSS OF REACTOR COOLANT FLOW (SEABROOK STATION UFSAR SECTIONS 15.3.1 AND 15.3.2)

The loss of reactor coolant flow events are categorized as follows:

- Flow coastdown accidents
- Locked-rotor accident

The first category includes the partial loss of flow, reactor coolant pump undervoltage and the reactor coolant pump underfrequency events. The second category includes the hypothetical event that addresses an instantaneous seizure of the rotor or break of the shaft of a reactor coolant pump.

6.3.4.1.1 PARTIAL LOSS OF REACTOR COOLANT FLOW

Accident Description

The partial loss of coolant flow accident can result from a mechanical or electrical failure in a reactor coolant pump or from a fault in the power supply to the reactor coolant pump. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in departure from nucleate boiling, with subsequent fuel damage, if the reactor protection system is not actuated promptly.

The plant design is such that the four reactor coolant pumps are supplied through two buses connected to the generator and the offsite power system. When a generator trip occurs, the buses continue to be supplied from external power lines, and the pumps continue to supply coolant to the core.

The necessary protection against a partial loss of coolant flow accident is provided by the low primary coolant flow reactor trip signal, which is actuated in any reactor coolant loop by two-out-of-three low flow signals, in any reactor coolant loop. Above Permissive 8, low flow in either loop will actuate a reactor trip. Between approximately 10 percent power (Permissive 7) and approximately 50% power (Permissive 8), low flow in any two loops will actuate a reactor trip. Above Permissive 7, either power supply low voltage on both buses or opening of one reactor coolant pump breaker on each bus will actuate the corresponding undervoltage relays, resulting in a reactor trip. Additionally, underfrequency on the two buses will actuate a reactor trip above Permissive 7. The undervoltage and underfrequency trips serve as a backup to the low flow trip.

Method of Analysis

The partial loss of flow involving loss of two reactor coolant pumps with four loops in operation is categorized as an American Nuclear Society Condition II event and is therefore analyzed to demonstrate that: (1) the integrity of the core is maintained as the

departure from nucleate boiling ratio remains above the safety analysis limit value, and (2) the peak Reactor Coolant System and secondary system pressures remain below the design limits. Of these, the primary concerns are departure from nucleate boiling and assuring that the departure from nucleate boiling ratio limit is met.

The partial loss of flow event is analyzed with two computer codes. First, the RETRAN computer code [Reference 6.3-1] is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE computer code [Reference 6.3-4] is then used to calculate the hot-channel heat flux transient and departure from nucleate boiling ratio, based on the nuclear power and Reactor Coolant System temperature (enthalpy), pressure, and flow from RETRAN.

This event is analyzed following the Revised Thermal Design Procedure [Reference 6.3-8]. Initial reactor power, pressurizer pressure, and Reactor Coolant System temperature are assumed to be at their nominal values. Minimum measured flow is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive moderator temperature coefficient allowed by the plant Technical Specifications for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum departure from nucleate boiling ratio is reached.

A limiting end of cycle departure from nucleate boiling axial power shape is assumed in VIPRE for the calculation of departure from nucleate boiling ratio. This shape provides the most limiting minimum departure from nucleate boiling ratio for the loss-of-flow events.

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 departure from nucleate boiling ratio evaluation for this event. This value is based on the assumption that the highest worth rod control cluster assembly is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time (2.4 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the Reload Safety Analysis Checklist verification process.

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics. Also, it is based on conservative estimates of system pressure losses.

A maximum, uniform, steam generator tube plugging level of 10 percent was assumed in the RETRAN analysis. In addition, a core flow penalty of 1.05 percent was applied to account for Reactor Coolant System loop-to-loop flow asymmetry in accordance with NSAL-00-008 [Reference 6.3-29].

Results

LAR Figures 6.3.4.1-1 through 6.3.4.1-3 illustrate the transient response for the loss of two reactor coolant pumps with four loops in operation. The minimum departure from

nucleate boiling ratio is 2.169, which occurred at 2.95 seconds (departure from nucleate boiling ratio limit: is 1.47).

The calculated sequence of events table is shown in LAR Table 6.3.4.1-1. This transient trips on a low primary reactor coolant flow trip setpoint, which is assumed to be 87 percent of loop flow. Following reactor trip, the affected reactor coolant pumps will continue to coast down, and the core flow will reach a new equilibrium value corresponding to the two pumps still in operation. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

Conclusions

The analysis performed has demonstrated that for the partial loss of coolant event, the departure from nucleate boiling design basis is met. Therefore, no fuel or cladding damage is predicted and all applicable acceptance criteria are met.

6.3.4.1.2 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in departure from nucleate boiling with subsequent fuel damage if the reactor were not tripped promptly.

Normal power for the reactor coolant pumps is supplied through buses from a transformer connected to the generator. When a generator trip occurs, the generator breaker is tripped open, the buses are automatically transferred to an offsite power source, and the pumps will continue to supply coolant flow to the core. Following a turbine trip, there is immediate generator trip and automatic transfer of the buses to offsite power.

The following signals provide the necessary protection against a complete loss-of-flow accident:

- Reactor coolant pump power supply undervoltage or underfrequency
- Low reactor coolant loop flow reactor trip

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions that can cause a loss of voltage to all reactor coolant pumps; that is, loss of offsite power. Channel response time includes consideration of the bus voltage decay time due to generated electro-motive force from motors connected to the bus as the motors coast down. This function is blocked below approximately 10-percent power (Permissive 7).

The reactor trip on reactor coolant pump underfrequency is provided to trip the reactor for an underfrequency condition, resulting from frequency disturbances on the power grid.

The reactor trip on low primary coolant flow is provided to protect against loss-of-flow conditions that affect only one reactor coolant loop. This function is generated by

two-out-of-three low flow signals per reactor coolant loop. Above approximately 50% power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive 7) and Permissive 8, low flow in any two loops will actuate a reactor trip. If the maximum grid frequency decay rate is less than approximately 2.5 Hz/second the low flow trip function will protect the core from underfrequency events.

The complete loss of flow event is classified as an American Nuclear Society Condition III event and therefore conservatively analyzed to demonstrate that the following acceptance criteria are met:

- Pressure in the Reactor Coolant System and Main Steam System should be maintained below 110 percent of the design values.
- Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio remains above the limit value.
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

Method of Analysis

The transients are analyzed with two computer codes. First, the RETRAN computer code [Reference 6.3-1] is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE computer code [Reference 6.3-4] is then used to calculate the heat flux and departure from nucleate boiling ratio transients based on the nuclear power and Reactor Coolant System temperature (enthalpy), pressure, and flow from RETRAN.

The complete loss-of-flow transient is analyzed for a loss of four reactor coolant pumps with four loops in operation. The event is analyzed to show that the integrity of the core is maintained as the departure from nucleate boiling ratio remains above the safety analysis limit value. The loss-of-flow events do result in an increase in Reactor Coolant System and Main Steam System pressures, but these pressure increases are generally not severe enough to challenge the integrity of the Reactor Coolant System and Main Steam System. Since the maximum Reactor Coolant System and Main Steam System pressures do not exceed 110 percent of their respective design pressures for the loss-of-load event, it is concluded that the maximum Reactor Coolant System and Main Steam System pressures will also remain below 110 percent of their respective design pressures for the loss-of-flow events.

Two cases are analyzed:

- Complete loss-of-flow transient due to a loss of power (undervoltage condition) to all reactor coolant pumps with four loops in operation
- Complete loss-of-flow transient due to a grid disturbance resulting in a frequency decay (underfrequency condition)

The first case assumes that the reactor coolant pumps begin to coastdown upon reaching an undervoltage trip setpoint (modeled to occur at t=0 seconds in this

analysis). Rod motion following the undervoltage trip is modeled to occur at t=1.5 seconds. The underfrequency case assumes a frequency decay rate of 5 Hz/s beginning at t=0 seconds, decreasing pump speed, and thus flow to all loops. At t=0.6 seconds, the underfrequency trip setpoint of 55.0 Hz is reached. Rod motion occurs at t=1.6 seconds, following a 1.0 second underfrequency trip time delay.

This event is analyzed with the Revised Thermal Design Procedure [Reference 6.3-8]. Initial reactor power, pressurizer pressure and Reactor Coolant System temperature are assumed to be at their nominal values. Minimum measured flow is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive moderator temperature coefficient allowed by the plant Technical Specifications for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum departure from nucleate boiling ratio is reached.

A limiting end of cycle departure from nucleate boiling axial power shape is assumed in VIPRE for the calculation of departure from nucleate boiling ratio. This shape provides the most limiting minimum departure from nucleate boiling ratio for the loss-of-flow events.

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 departure from nucleate boiling ratio evaluation for this event. This value is based on the assumption that the highest worth rod control cluster assembly is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time (2.4 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the Reload Safety Analysis Checklist verification process.

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics. Also, it is based on conservative estimates of system pressure losses.

A maximum, uniform, steam generator tube plugging level of 10 percent was assumed in the RETRAN analysis. Reactor Coolant System loop-to-loop flow asymmetry does not need to be considered for transients in which all reactor coolant loops experience a symmetric flow coastdown.

Results

LAR Figures 6.3.4.1-4 through 6.3.4.1-6 illustrate the transient response for the complete loss of flow associated with a loss of power to all reactor coolant pumps (undervoltage case) with four loops in operation. The minimum departure from nucleate boiling ratio is 2.064 which occurred at 2.7 seconds (departure from nucleate boiling ratio limit: is 1.47).

LAR Figures 6.3.4.1-7 through 6.3.4.1-9 illustrate the transient response for the complete loss-of-flow (underfrequency) case. The minimum departure from nucleate boiling ratio is 1.998, which occurred at 3.1 seconds (departure from nucleate boiling

ratio limit: is 1.47). These results are based on a cycle-specific worst-power shape that was utilized to obtain margin between the safety analysis departure from nucleate boiling ratio limit and the design departure from nucleate boiling ratio limit.

The calculated sequence of events for both complete loss-of-flow cases are shown in LAR Table 6.3.4.1-2. Following reactor trip, the reactor coolant pumps will continue to coast down, and natural circulation flow will eventually be established. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

Conclusions

The analysis performed has demonstrated that for the complete loss-of-flow event, the departure from nucleate boiling design basis is met. Therefore, no fuel or cladding damage is predicted and all applicable acceptance criteria are met.

6.3.4.2 REACTOR COOLANT PUMP LOCKED ROTOR / SHAFT BREAK (SEABROOK STATION UFSAR SECTIONS 15.3.3 AND 15.3.4)

6.3.4.2.1 ACCIDENT DESCRIPTION

The postulated locked rotor accident is an instantaneous seizure of a reactor coolant pump rotor. Flow through the affected reactor coolant loop is rapidly reduced, leading to an initiation of a reactor trip on a low flow signal. The consequences of a postulated pump shaft break accident are similar to the locked rotor event. With a broken shaft, the impeller is free to spin, as opposed to it being fixed in position during the locked rotor event. Therefore, the initial rate of reduction in core flow is greater during a locked rotor event than in a pump shaft break event because the fixed shaft causes greater resistance than a free spinning impeller early in the transient, when flow through the affected loop is in the positive direction. As the transient continues, the flow direction through the affected loop is reversed. If the impeller is free to spin as the flow reverses in the affected loop, the core inlet flow rate will be less than that expected if the reactor coolant pump impeller is assumed to be seized. Because peak pressure, cladding temperature, and departure from nucleate boiling occur very early in the transient, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Consequently, the bounding results for the locked rotor transients also are applicable to the reactor coolant pump shaft break.

After the reactor coolant pump impeller seizes, reactor trip is initiated on an Reactor Coolant System low flow signal. At the time of reactor trip, the unaffected reactor coolant pumps are assumed to lose power and coast down freely.

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. This is because, first, the reduced flow results in a decreased tube side film coefficient; and then because the reactor coolant in the tubes cools down while the shell side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam

generators, causes an insurge into the pressurizer and a pressure increase throughout the Reactor Coolant System. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves, in that sequence. The two power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism in the peak pressure evaluation, their pressure reducing effect and the pressure reducing effect of the pressurizer sprays are not included in the analysis.

The locked rotor event is classified as an American Nuclear Society Condition IV event and therefore conservatively analyzed to demonstrate that the following acceptance criteria are met:

- Pressure in the primary and secondary Reactor Coolant System should be maintained below 120% of the design pressure limit for a very low probability event. However, the more restrictive criterion of 110% is applied to this analysis. Therefore, the both the primary and secondary Reactor Coolant System should be maintained below 110 percent of the design value.
- Coolable core geometry is ensured by showing that the peak cladding temperature and maximum oxidation level for the hot spot are below 2700°F and 16.0 percent by weight, respectively.
- Activity release is such that the calculated doses meet 10 CFR 50.67 limits.

For the locked-rotor event, a primary Reactor Coolant System overpressure analysis is performed to demonstrate that the first criterion is met. Since the loss of load analysis bounds the locked rotor due to conservative analysis, a specific Main Steam System overpressurization analysis is not performed for the locked-rotor event. Additionally, a hot spot evaluation is performed to calculate the peak cladding temperature and maximum oxidation level to address the second criterion. Finally, a calculation of the "rods-in-departure from nucleate boiling" is performed for input to the radiological dose analysis summarized in the Alternate Source Term License Amendment Request [Reference 6.2-6].

6.3.4.2.2 METHOD OF ANALYSIS

The locked rotor transient is analyzed with two computer codes. First, the RETRAN computer code [Reference 6.3-1] is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code [Reference 6.3-4] is then used to calculate the thermal behavior of the fuel located at the core hot spot based on the nuclear power and Reactor Coolant System flow from RETRAN. The VIPRE computer code includes a film boiling heat transfer coefficient. The VIPRE code is also used to calculate the rods in departure from nucleate boiling using the nuclear power and Reactor Coolant System temperature (enthalpy), pressure, and flow from RETRAN.

The case analyzed to determine the maximum Reactor Coolant System pressure and peak cladding temperature utilizes the Standard Thermal Design Procedure. The plant

is assumed to be in operation under the most adverse steady-state operating conditions including applicable uncertainties applied in the most adverse direction; that is, thermal design flow, maximum steady-state power level, maximum steady-state pressure, and maximum steady-state coolant average temperature.

The case analyzed to determine the rods in departure from nucleate boiling utilizes the Revised Thermal Design Procedure [Reference 6.3-8] methodology. Initial reactor power, pressurizer pressure and Reactor Coolant System temperature are assumed to be at their nominal values. Minimum measured flow is also assumed.

A maximum, uniform, steam generator tube plugging level of 10 percent was assumed in the RETRAN analysis. In addition, a 1.05% core flow penalty was applied to account for Reactor Coolant System loop-to-loop flow asymmetry.

A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most positive moderator temperature coefficient allowed by the plant Technical Specifications for full power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the peak Reactor Coolant System pressures and hot spot results are 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 departure from nucleate boiling ratio evaluation for this event. This value is based on the assumption that the highest worth rod control cluster assembly is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time (2.4 seconds from dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the Reload Safety Analysis Checklist verification process.

A loss of offsite power is assumed to occur at the time of reactor trip resulting in a coastdown of the unaffected reactor coolant pumps. No delay is conservatively assumed between the time of loss of offsite power and the time that the coastdown of the unaffected reactor coolant pumps begins.

For the peak Reactor Coolant System pressure evaluation, the initial pressure is conservatively selected as the nominal value (2250 psia) plus uncertainty (50 psi) to allow for errors in the pressurizer pressure measurement and control channels. This results in calculating the highest possible rise in the coolant pressure during the transient, which occurs in the lower plenum of the reactor vessel.

For this accident, an evaluation of the consequences with respect to the fuel rod thermal transient is performed. The evaluation incorporates the assumption of rods going into departure from nucleate boiling as a conservative initial condition to determine the cladding temperature and zirconium water reaction resulting from the locked rotor. Results obtained from the analysis of this hot spot condition represent the upper limit with respect to cladding temperature and zirconium water reaction. In the evaluation, the rod power at the hot spot is assumed to be 2.5 times the average rod power (that is, $F_Q = 2.5$) at the initial core power level.

Film Boiling Coefficient

The film boiling coefficient is calculated in the VIPRE code using the Bishop-Sandberg-Tong film boiling correlation [Reference 6.3-16]. The fluid properties are evaluated at film temperature. The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and Reactor Coolant System flow rate as a function of time are based on the RETRAN results.

Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial fuel temperature to 10,000 BTU/hr ft^2 °F at the initiation of the transient. Therefore, the large amount of energy stored in the fuel because of the small initial value is released to the cladding at the initiation of the transient.

Zirconium Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (cladding temperature). The Baker Just parabolic rate equation is used to define the rate of zirconium-steam reaction [Reference 6.3-18]. The effect of the zirconium-steam reaction is included in the calculation of the hot spot cladding temperature transient.

6.3.4.2.3 RESULTS

LAR Figures 6.3.4.2-1 through 6.3.4.2-3 illustrate the transient response for the locked rotor event (peak Reactor Coolant System pressure/peak cladding temperature case). The peak Reactor Coolant System pressure is 2544 psia and is less than the acceptance criterion of 2750 psia. Also, the peak cladding temperature is 1650°F, which is considerably less than the limit of 2700°F. The zirconium-steam reaction at the hotspot is 0.20 percent by weight, which meets the criterion of less than 16 percent zirconium-steam water reaction. For the radiological dose evaluation, there were no fuel rods which experience departure from nucleate boiling (rods-in- departure from nucleate boiling case). The sequence of events for the peak Reactor Coolant System pressure/peak cladding temperature case is given in LAR Table 6.3.4.2-1. This transient trips on a low primary reactor coolant flow trip setpoint, which is assumed to be 87 percent. The radiological consequences are discussed in LAR Section 6.6.

6.3.4.2.4 CONCLUSIONS

The analysis performed has demonstrated that for the locked rotor event, the Reactor Coolant System pressure remains below 110 percent of the design pressure and the hot spot cladding temperature and oxidation levels remain below the limit values. Therefore, all applicable acceptance criteria are met. In addition, there were no fuel rods which experience departure from nucleate boiling.

TABLE 6.3.4.1-1
SEQUENCE OF EVENTS
PARTIAL LOSS OF REACTOR COOLANT FLOW

Event	Time (seconds)
Two operating reactor coolant pumps loses power and begins coasting down	0.0
Low flow reactor trip setpoint is reached	1.5
Rods begin to drop	2.5
Minimum departure from nucleate boiling ratio occurs	2.95

TABLE 6.3.4.1-2
SEQUENCE OF EVENTS
COMPLETE LOSS OF REACTOR COOLANT FLOW

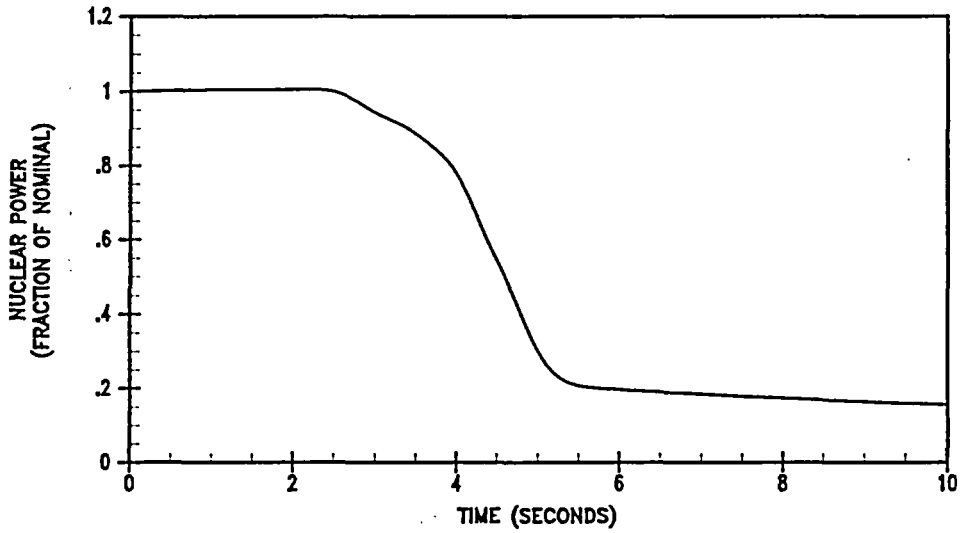
Complete Loss of Flow – Undervoltage Event	**Time (seconds)**
All operating reactor coolant pumps lose power and coastdown begins	0.0
Reactor coolant pump undervoltage setpoint reached	0.0
Rods begin to drop	1.5
Minimum departure from nucleate boiling ratio occurs	2.7
Complete Loss of Flow – Underfrequency Event	**Time (seconds)**
Frequency decay begins	0.0
Reactor coolant pump underfrequency setpoint reached and all pumps begin to coastdown	0.6
Rods begin to drop	1.6
Minimum departure from nucleate boiling ratio occurs	3.1

TABLE 6.3.4.2-1
SEQUENCE OF EVENTS
REACTOR COOLANT PUMP LOCKED ROTOR

Event	Time (seconds)
Rotor on one pump locks	0.00
Low flow reactor trip setpoint reached	0.045
Rods begin to drop	1.045
Maximum Reactor Coolant System pressure occurs	4.55
Maximum cladding temperature occurs	3.35

TABLE 6.3.4.2-2
SUMMARY OF RESULTS FOR THE LOCKED ROTOR/SHAFT BREAK TRANSIENT

Criteria	Analysis Value	Limit
Maximum clad temperature at core hot spot, °F	1650	2700
Maximum Zr-H_2O reaction at core hot spot, wt. %	0.20	16
Maximum Reactor Coolant System pressure, psia	2544	2750



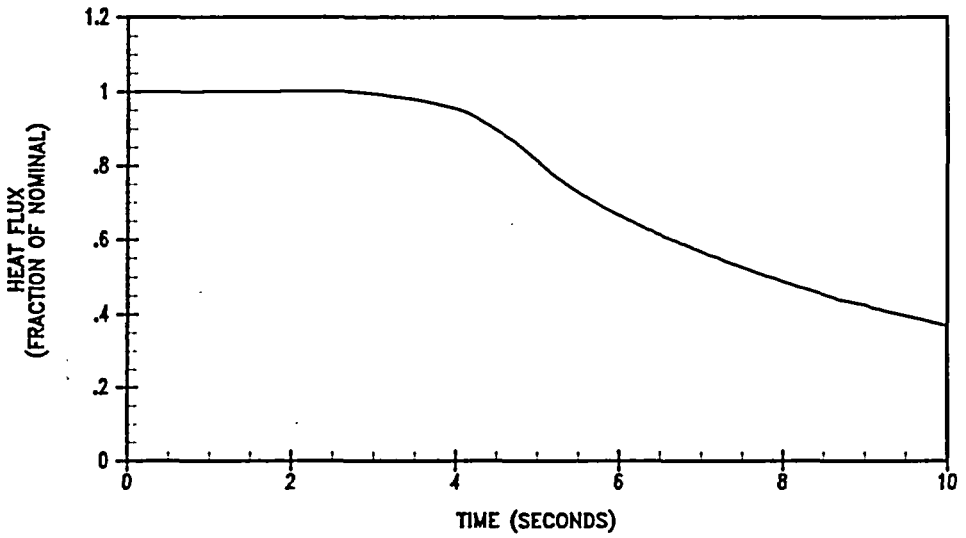


Figure 6.3.4.1-1
Partial Loss of Flow
(4 Loops in Operation, 2 Reactor Coolant Pumps Coasting Down)
Nuclear Power and Heat Flux versus Time

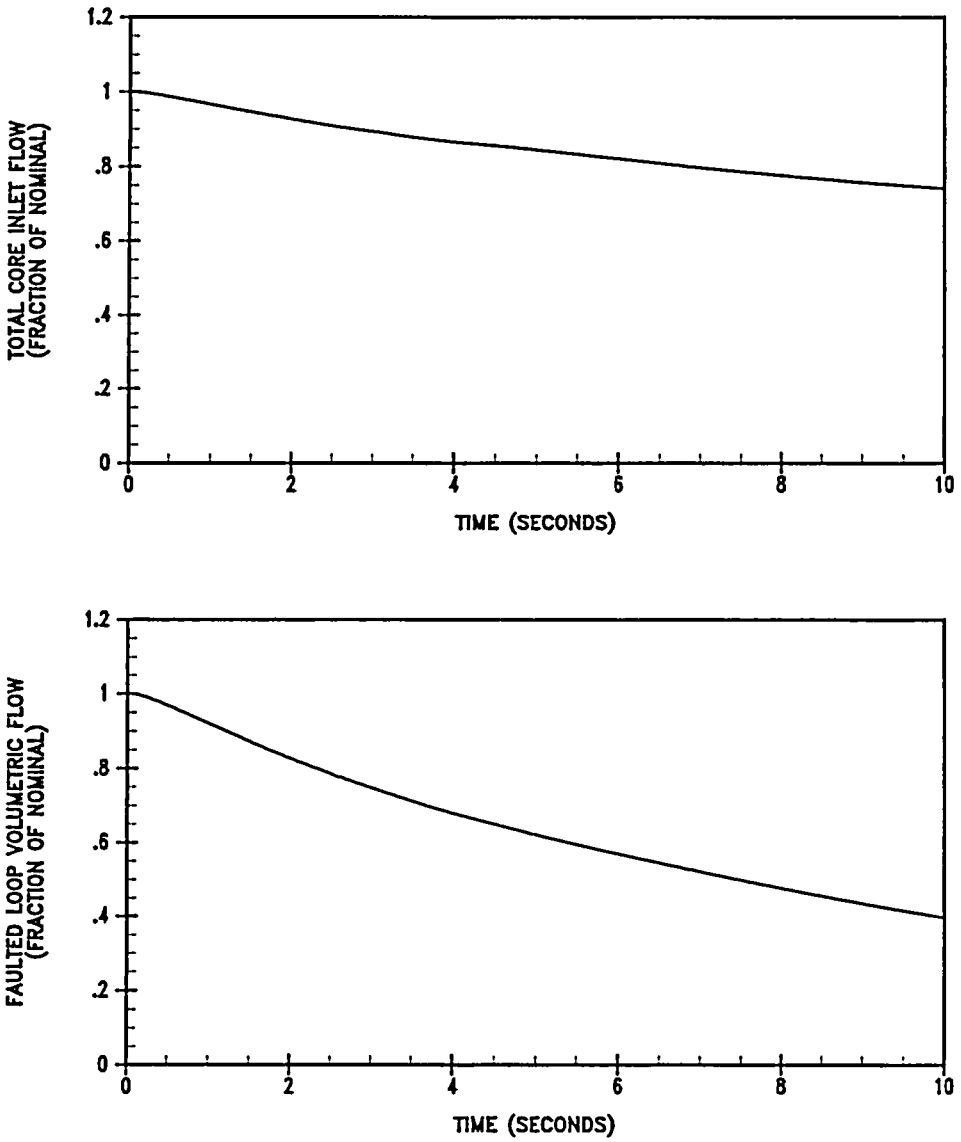


Figure 6.3.4.1-2
Partial Loss of Flow
(4 Loops in Operation, 2 Reactor Coolant Pumps Coasting Down)
Total Core Flow and Faulted Loop Flow versus Time

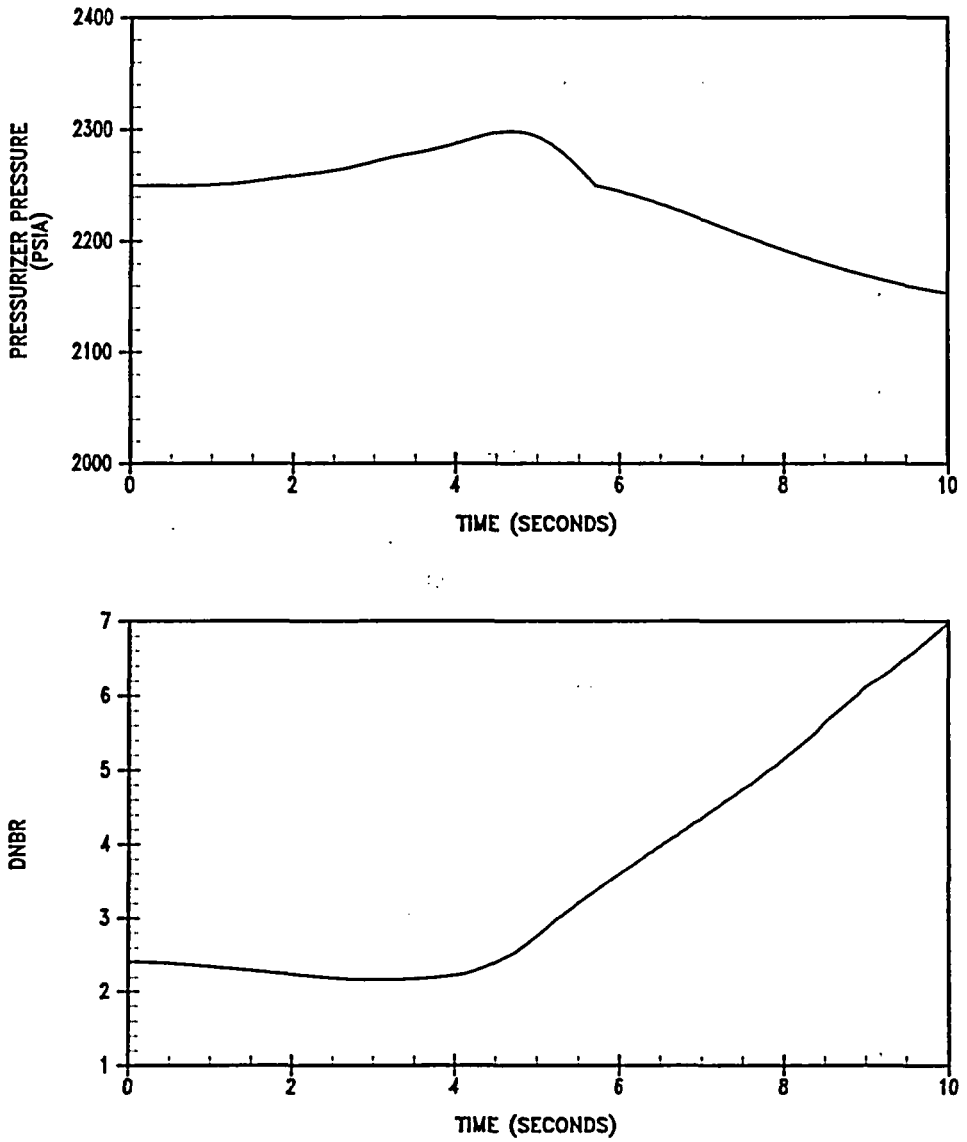
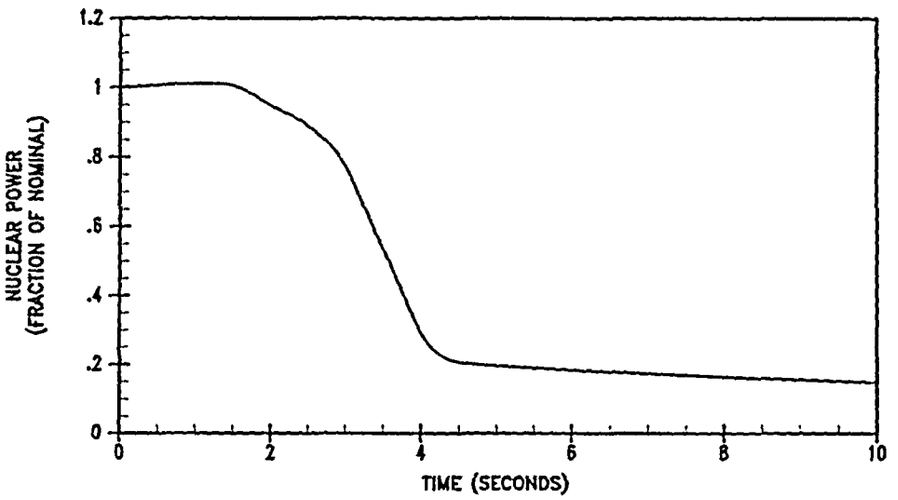


Figure 6.3.4.1-3
Partial Loss of Flow
(4 Loops in Operation, 2 Reactor Coolant Pumps Coasting Down)
Reactor Coolant System Pressure and Departure from Nucleate Boiling Ratio versus Time



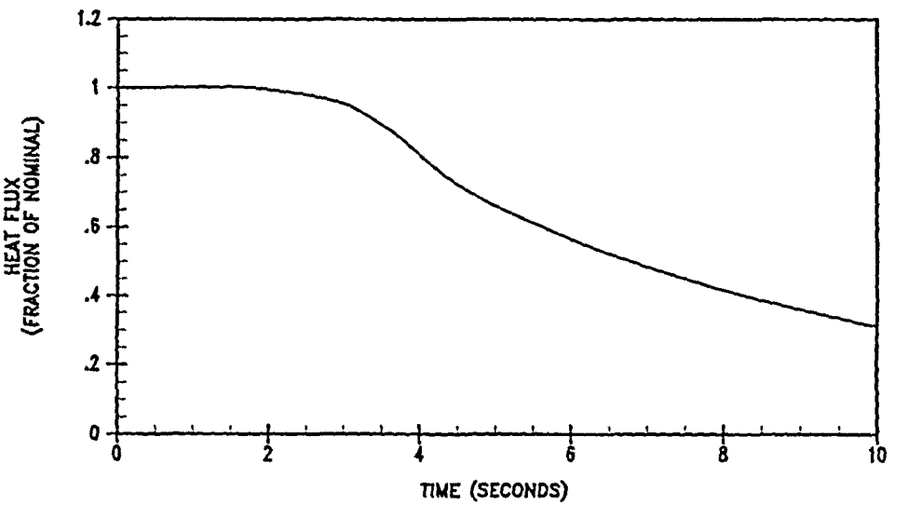
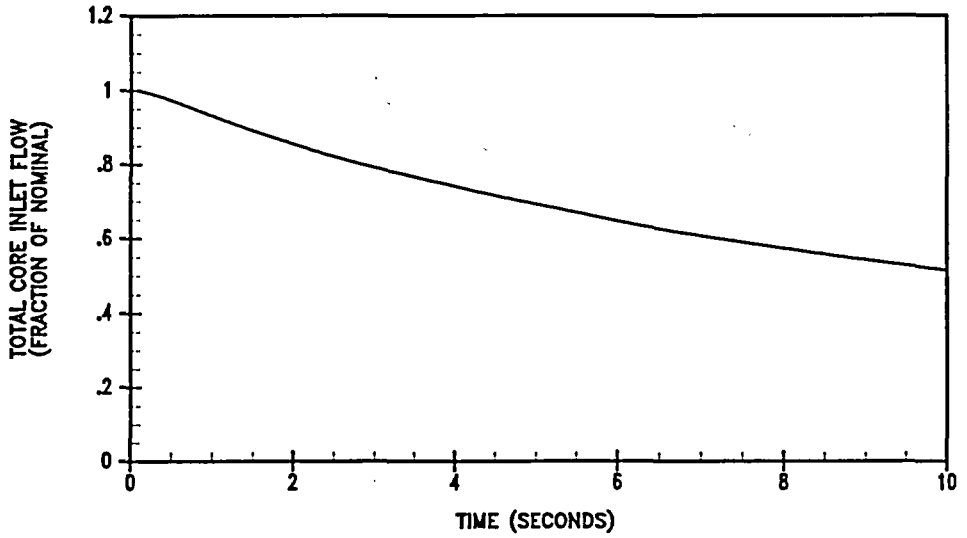


Figure 6.3.4.1-4
Complete Loss of Flow
(4 Loops in Operation, 4 Reactor Coolant Pumps Coasting Down)
Nuclear Power and Heat Flux versus Time



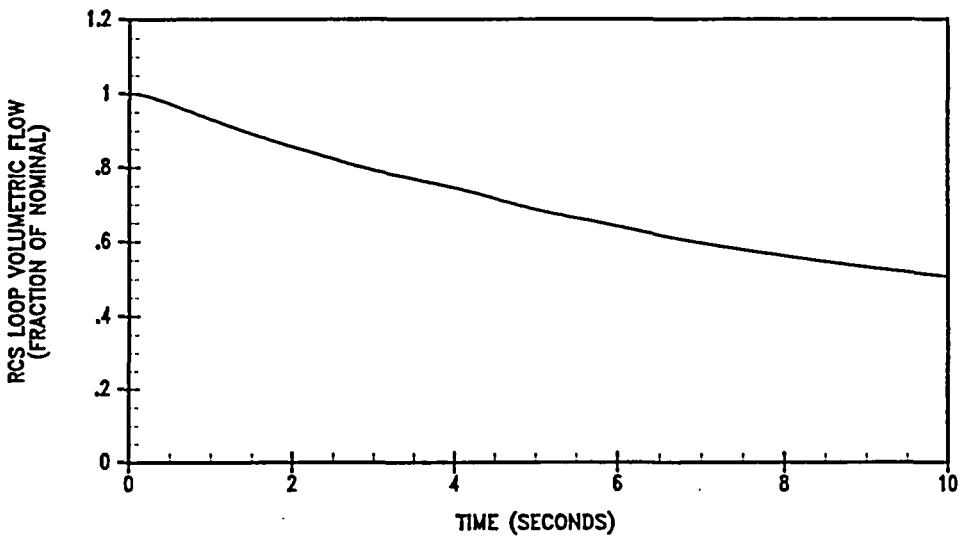


Figure 6.3.4.1-5
Complete Loss of Flow
(4 Loops in Operation, 4 Reactor Coolant Pumps Coasting Down)
Total Core Flow and Reactor Coolant System Loop Flow versus Time

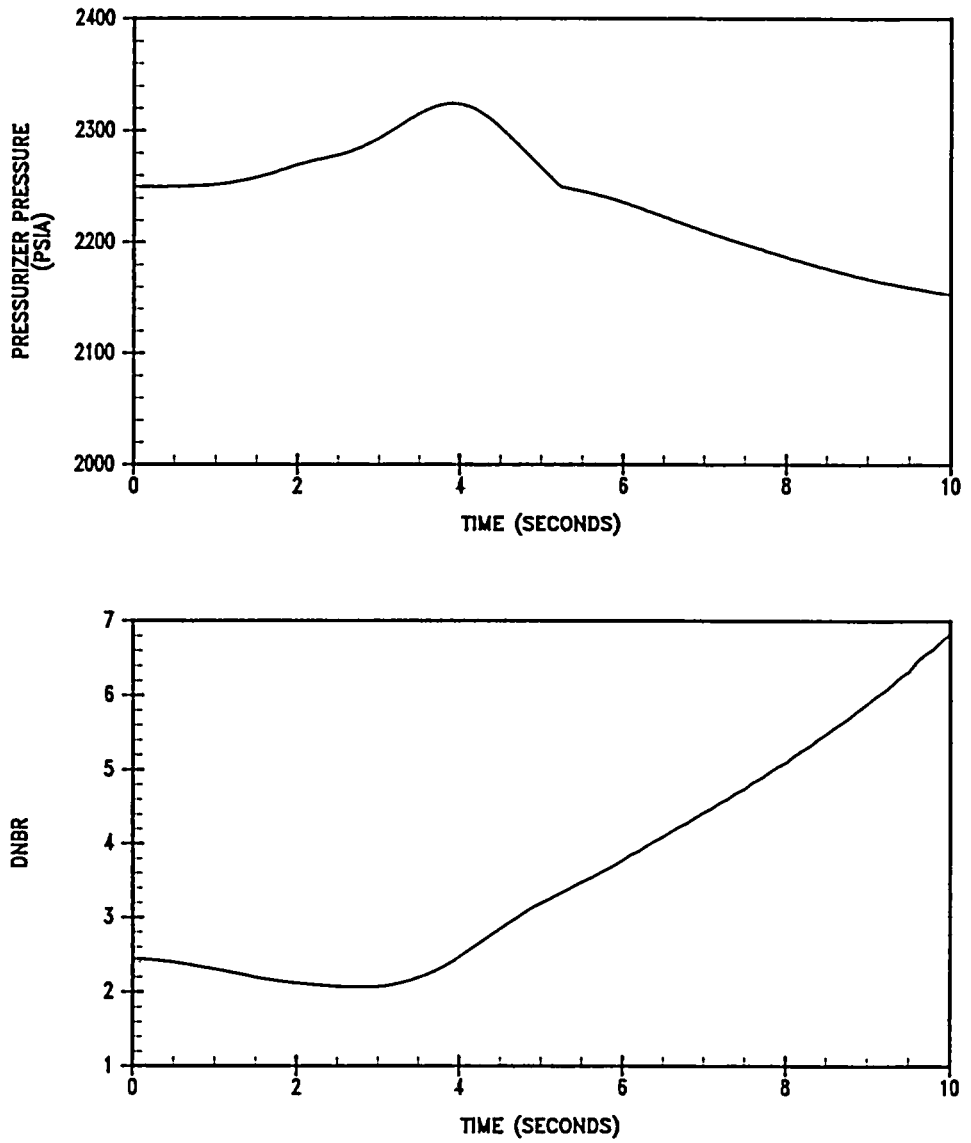


Figure 6.3.4.1-6
Complete Loss of Flow
(4 Loops in Operation, 4 Reactor Coolant Pumps Coasting Down)
Reactor Coolant System Pressure and Departure from Nucleate Boiling Ratio versus Time

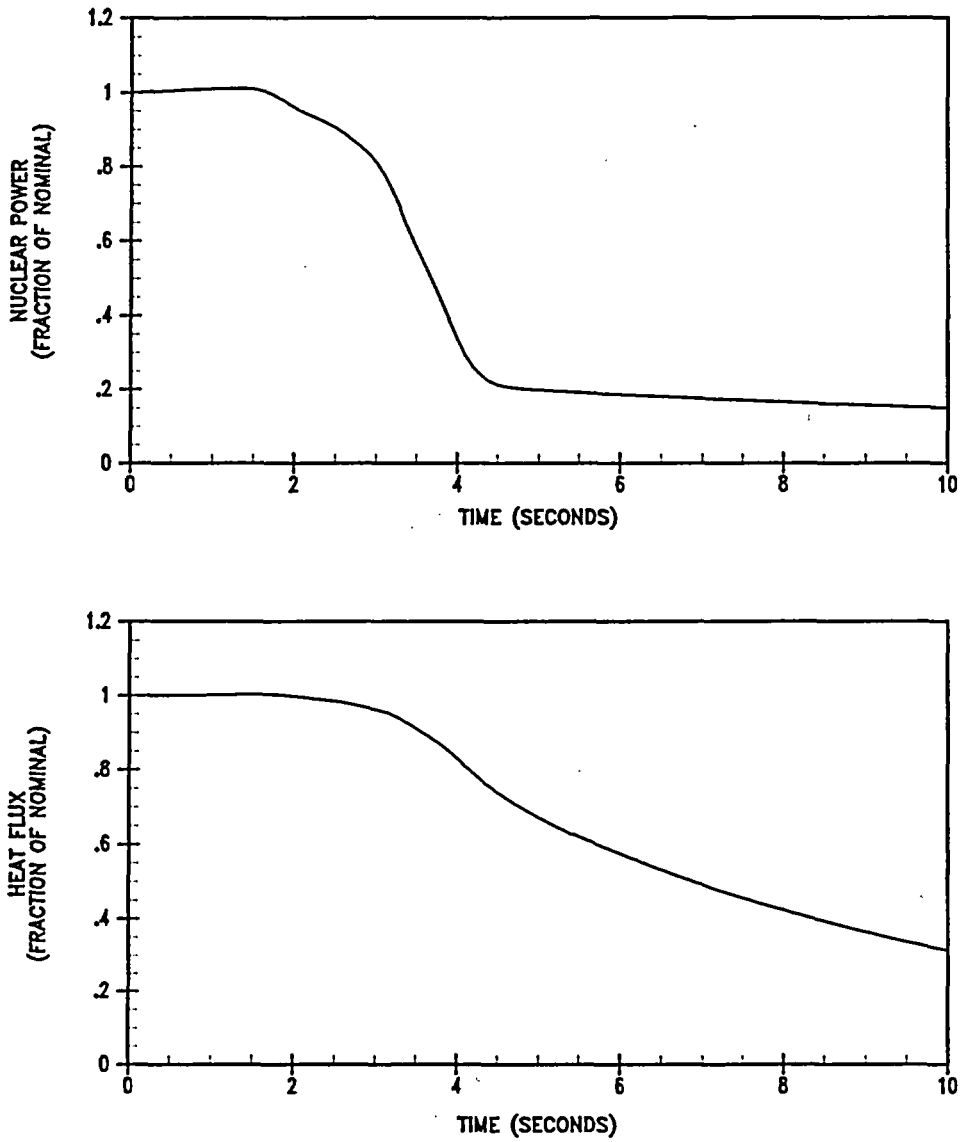
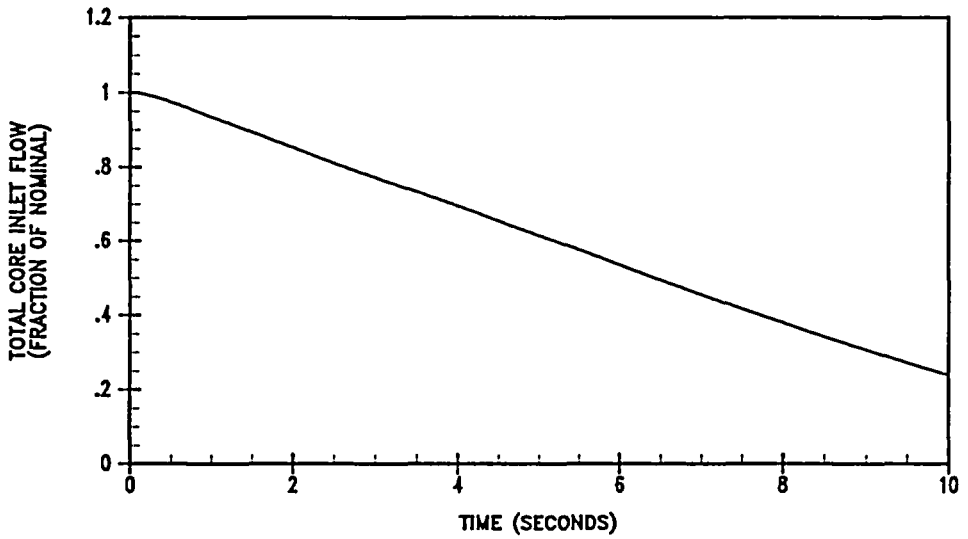


Figure 6.3.4.1-7
Complete Loss of Flow
(Frequency Decay)
Nuclear Power and Heat Flux versus Time



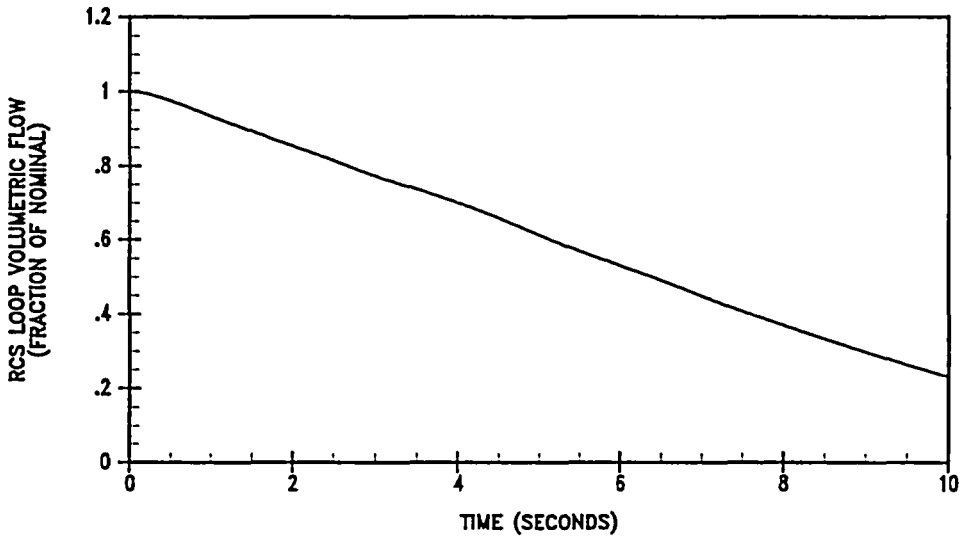
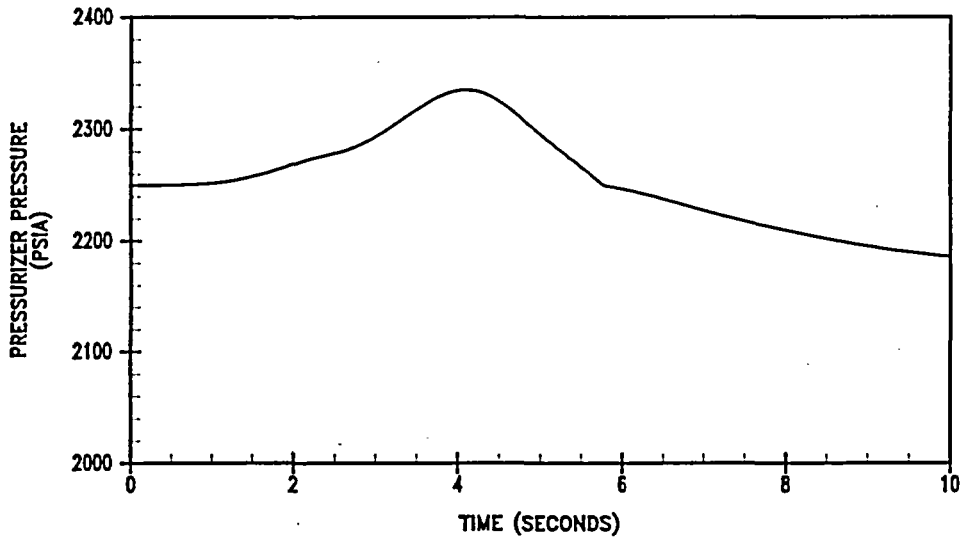


Figure 6.3.4.1-8
Complete Loss of Flow
(Frequency Decay)
Total Core Flow and Reactor Coolant System Loop Flow versus Time



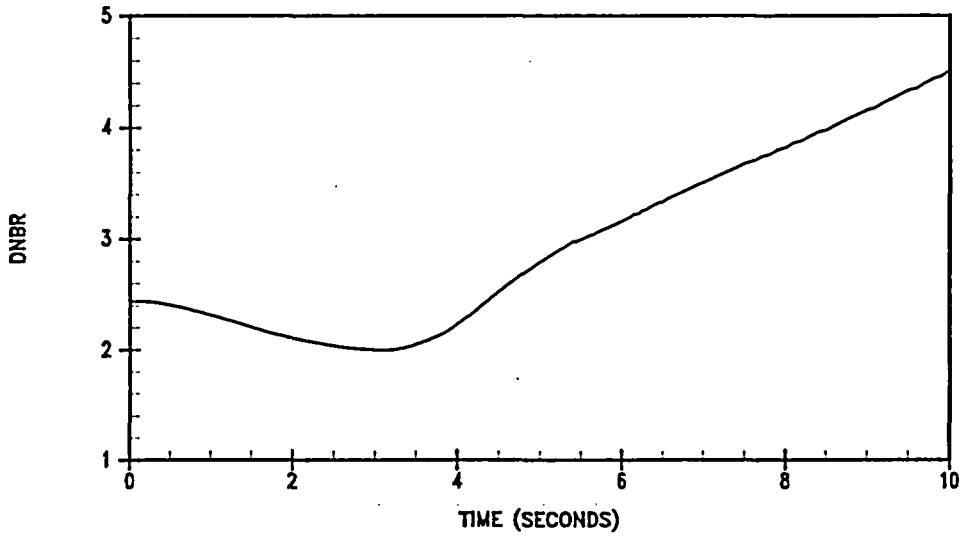


Figure 6.3.4.1-9
Complete Loss of Flow
(Frequency Decay)
Reactor Coolant System Pressure and Departure from Nucleate Boiling Ratio versus Time

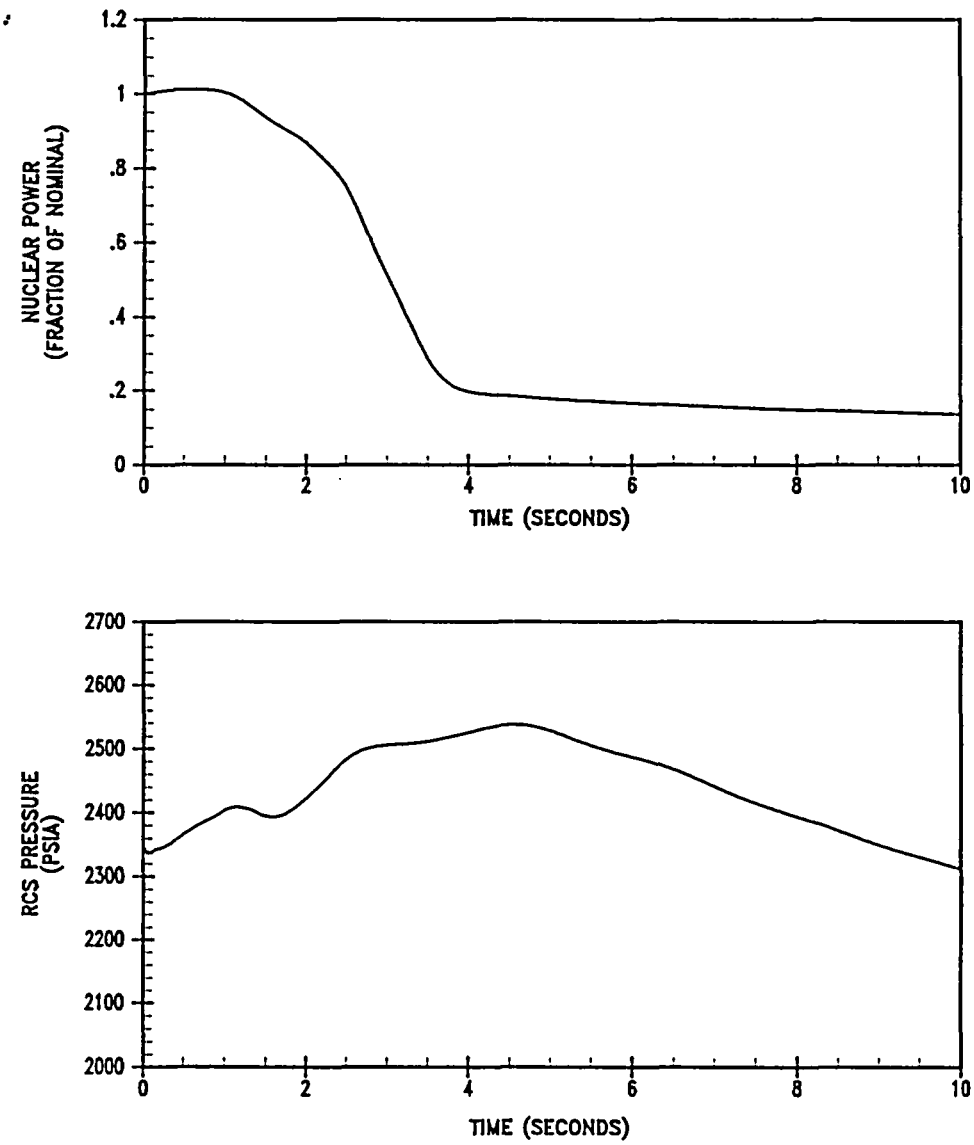
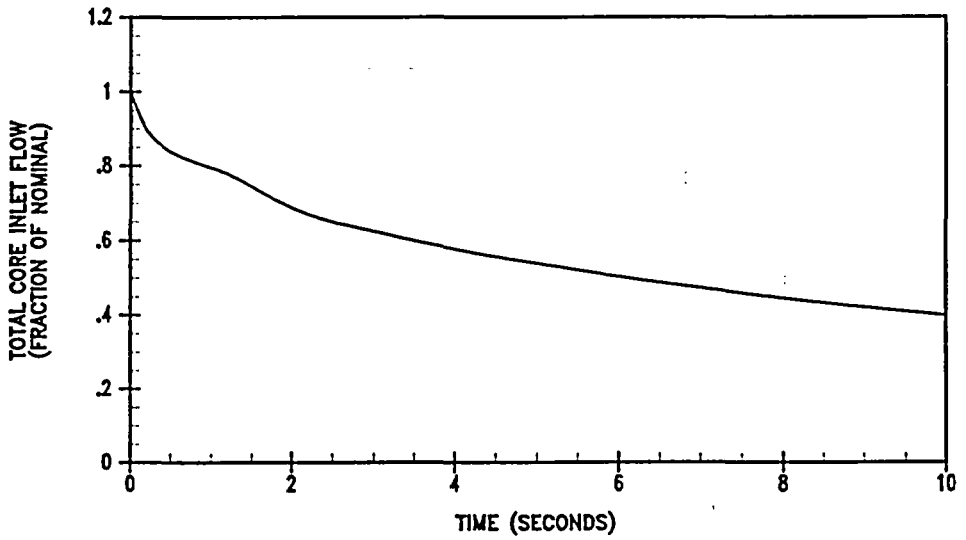


Figure 6.3.4.2-1
Locked Rotor / Shaft Break
Nuclear Power and Reactor Coolant System Pressure versus Time



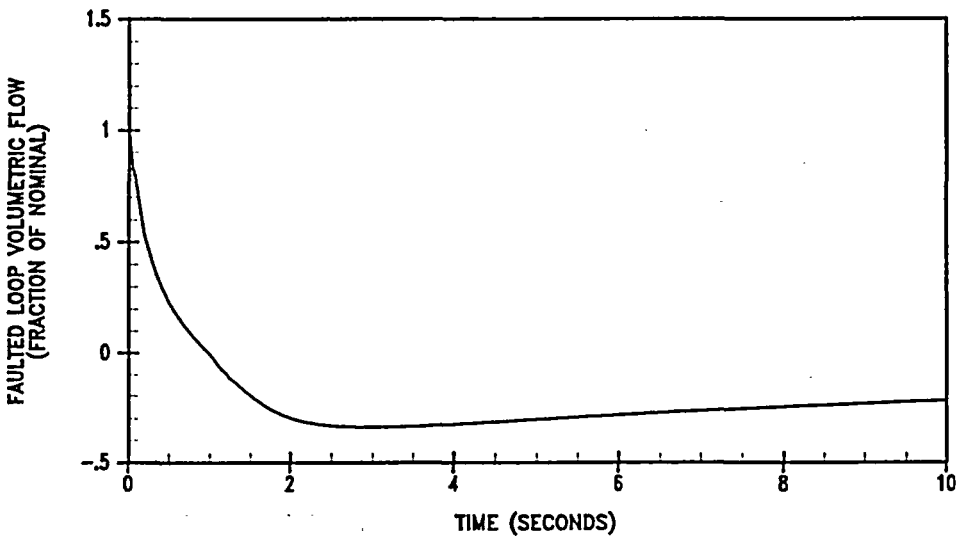
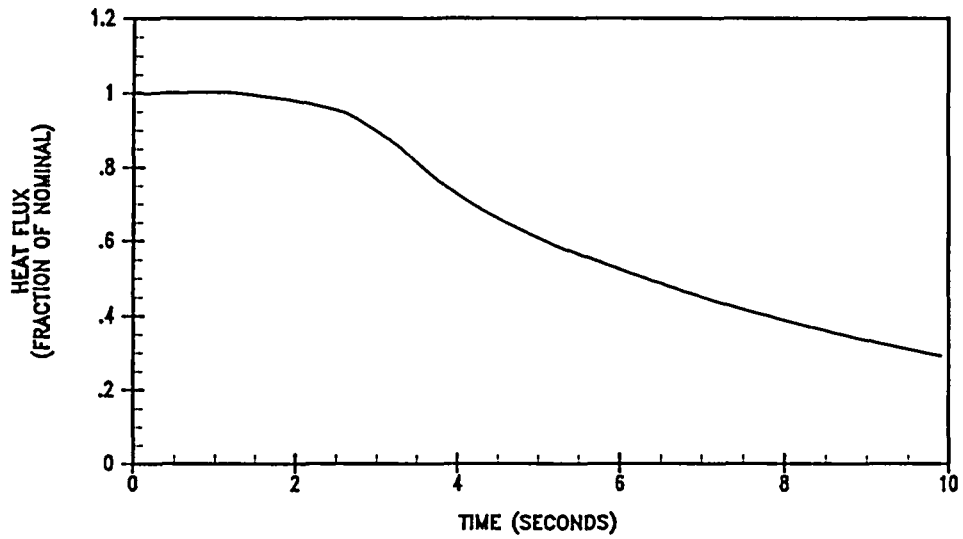


Figure 6.3.4.2-2
Locked Rotor / Shaft Break
Total Core Flow and Faulted Loop Flow versus Time



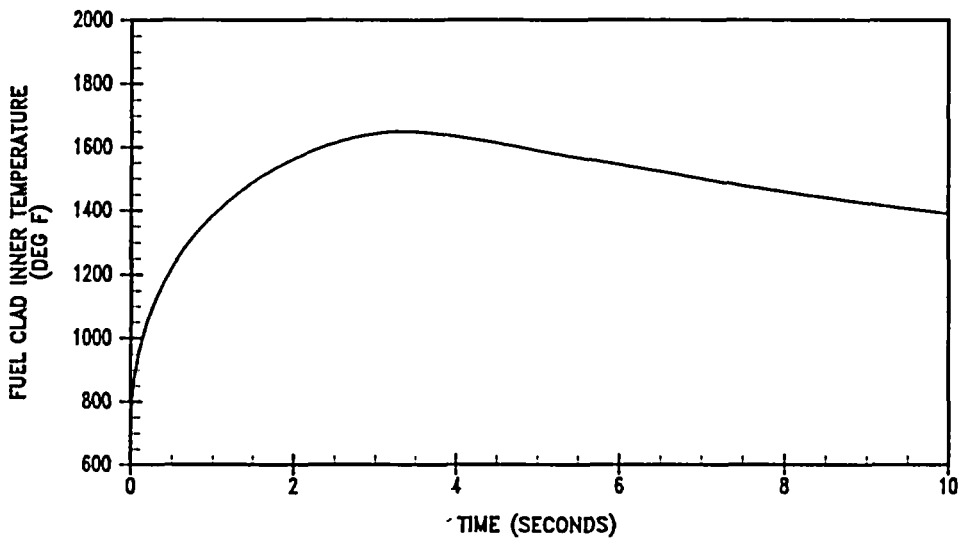


Figure 6.3.4.2-3
Locked Rotor / Shaft Break
Heat Flux and Clad Inner Temperature versus Time

6.3.5 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

6.3.5.1 UNCONTROLLED ROD CONTROL CLUSTER ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL CONDITION (SEABROOK STATION UFSAR SECTION 15.4.1)

6.3.5.1.1 ACCIDENT DESCRIPTION

The rod control cluster assembly withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of rod control cluster assembly banks resulting in a power excursion. While the occurrence of a transient of this type is unlikely, such a transient could be caused by a malfunction of the reactor control or the control rod drive system. This could occur with the reactor either subcritical, at hot zero power, or at power. The "at power" case is discussed in LAR Section 6.3.5.2.

Withdrawal of an rod control cluster assembly bank adds reactivity at a prescribed and controlled rate to bring the reactor from a subcritical condition to a low power level during startup. Although the initial startup procedure uses the method of boron dilution, the normal startup is with rod control cluster assembly bank withdrawal. Rod control cluster assembly bank movement can cause much faster changes in reactivity than can be made by changing boron concentration (see LAR Section 6.3.5.5, Chemical and Volume Control System Malfunction).

The rod control cluster assembly drive mechanisms are wired into preselected bank configurations that are not altered during reactor life. These circuits prevent rod control cluster assemblies from being automatically withdrawn in other than their respective banks. Power supplied to the rod banks is controlled so that no more than two banks can be withdrawn at the same time and in their proper withdrawal sequence. The rod control cluster assembly drive mechanisms are of the magnetic latch type; and coil actuation is sequenced to provide variable speed travel. The analysis of the maximum reactivity insertion rate includes the assumption of the simultaneous withdrawal of the two sequential banks having the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous control rod assembly withdrawal event occur, the following automatic features of the reactor protection system are available to terminate the transient.

1. The source range high neutron flux reactor trip is actuated when either of two independent source range channels indicates a neutron flux level above a preselected manually adjustable setpoint and provides primary protection below the P6 permissive. This trip function may be manually bypassed when either intermediate range flux channel indicates a flux level above P6. It is automatically reinstated when both intermediate-range channels indicate a flux level below P6.

2. The intermediate range high neutron flux reactor trip is actuated when either of two independent intermediate-range channels indicates a flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed when two of the four power-range channels give readings above the P10 permissive (approximately 10% of full power) and is automatically reinstated when three of the four channels indicate a power below P10.
3. The power range high neutron flux reactor trip (low setting) is actuated when two-out-of-four power-range channels indicate a power level above approximately 25% of full power. This trip function may be manually bypassed when two of the four power-range channels indicate a power level above the P10 permissive and is automatically reinstated when three of the four channels indicate a power level below P10.
4. The power range high neutron flux reactor trip (high setting) is actuated when two-out-of-four power-range channels indicate a power level above a preset setpoint. This trip function is always active while the reactor is at power.
5. The high nuclear flux rate reactor trip is actuated when the positive rate of change of neutron flux on two-out-of-four nuclear power range channels indicate a rate above the preset setpoint. This trip function is always active while the reactor is at power.

In addition, control rod stops on high intermediate range flux (one-out-of-two) and high power-range flux (one-out-of-four) serve to cease rod withdrawal and prevent the need to actuate the intermediate-range flux trip and the power-range flux trip, respectively.

6.3.5.1.2 METHOD OF ANALYSIS

The analysis of the uncontrolled rod control cluster assembly bank withdrawal from subcritical accident is performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE, is used to calculate the core average nuclear power transient, including the various core feedback effects, i.e., Doppler and moderator reactivity. FACTRAN uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the average heat flux and temperature transients. Finally, the peak core-average heat flux calculated by FACTRAN is used in VIPRE for transient departure from nucleate boiling ratio calculations.

In order to give conservative results for a startup accident, the following assumptions are made.

1. Since the magnitude of the power peak reached during the initial part of the transient for a given rate of reactivity insertion is strongly dependent on the Doppler power coefficient, a conservatively low (absolute magnitude) value for the Doppler power defect is used (900 pcm).
2. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and the moderator is much longer than the neutron flux response time constant. However, after the initial neutron flux peak, the moderator temperature coefficient

can affect the succeeding rate of power increase. The effect of moderator temperature changes on the rate of nuclear power increase is calculated in TWINKLE based on temperature-dependent moderator cross-sections. The moderator temperature coefficient value used in the rod withdrawal from subcritical event analysis is + 5 pcm/°F.

3. The analysis assumes the reactor to be at hot zero power nominal temperature of 557 °F. This assumption is more conservative than that of a lower initial system temperature (i.e., shutdown conditions). The higher initial system temperature yields a larger fuel-to-water heat transfer coefficient, a larger specific heat of the water 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 assumes the initial effective multiplication factor (k_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

4. Reactor trip is assumed to be initiated by power-range high neutron flux (low setting). The most adverse combination of instrumentation and setpoint errors are accounted for by assuming a 10% increase in the power range flux trip setpoint (low setting), raising it from the nominal value of 25% to a value of 35%. LAR Figure 6.3.5.1-1 shows that the rise in nuclear flux is so rapid that the effect of error in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth rod cluster control assembly is stuck in its fully withdrawn position. Further, the delays for trip signal actuation and control rod assembly release are accounted for in the reactor trip delay time as shown in LAR Table 6.3.5.1-2.

5. The maximum positive reactivity insertion rate assumed (100 pcm/in) is a plant-specific value confirmed for each reload cycle and is equal to that for the simultaneous withdrawal of the two sequential control banks having the greatest combined worth at a conservative speed (45 in/min, which corresponds to 72 steps/min).

6. The departure from nucleate boiling analysis assumes the most-limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their high worth position.

7. The analysis assumes the initial power level to be below the power level expected for a 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.

8. The analysis is performed at hot zero power conditions with two of four reactor coolant pumps in operation and bounds this accident in lower modes. This assumption also minimizes the resulting departure from nucleate boiling ratio.

9. A core flow reduction of 1.1 percent, which addresses the potential reactor coolant flow asymmetry associated with a maximum loop-to-loop steam generator tube

plugging imbalance of 10 percent, has been applied in accordance with NSAL-00-008 [Reference 6.3-29].

10. The accident analysis employs the standard thermal design procedure methodology. Use of the standard thermal design procedure stipulates that the Reactor Coolant System flow rate will be based on the Thermal Design Flow and that the Reactor Coolant System pressure is the nominal pressure minus the uncertainty. Since the event is analyzed from hot zero power, the steady-state standard thermal design procedure uncertainties on core power and Reactor Coolant System average temperature are not considered in defining the initial conditions.

11. The fuel rod heat transfer calculations performed to determine temperature transients during this event assume a total peaking factor or hot channel factor, F_Q, that is a function of the axial and radial power distributions. The conservatively high value used in this analysis is presented in LAR Table 6.3.5.1-1.

6.3.5.1.3 RESULTS

LAR Figures 6.3.5.1-1 through 6.3.5.1-5 show the transient behavior for a reactivity insertion rate of 75 pcm/sec, with the accident terminated by the reactor trip at 35% of nominal power. The rate of 75 pcm/sec is converted from 100 pcm/in by using a factor of 45 in/min. The rate is greater than that calculated for the two highest worth sequential control banks, with both assumed to be in their highest incremental worth region.

LAR Figure 6.3.5.1-1 shows the neutron flux transient. The neutron flux overshoots the full power nominal value for a very short period of time; therefore, the energy release and fuel temperature increase are relatively small. The heat flux response of interest for the departure from nucleate boiling considerations is shown in LAR Figure 6.3.5.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux of much less than the nominal full power value. LAR Figures 6.3.5.1-3 through 6.3.4.1–5 show the transient response of the hot spot fuel centerline, fuel average, and cladding temperatures, respectively. Transient departure from nucleate boiling ratio calculations indicate that the minimum departure from nucleate boiling ratio remains above the safety analysis limit value at all times.

LAR Table 6.3.5.1-1 presents the assumptions and results of the analysis. LAR Table 6.3.5.1-2 presents the calculated sequence of events. After reactor trip, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal shutdown procedures.

6.3.5.1.4 CONCLUSIONS

In the event of a rod control cluster assembly withdrawal accident from the subcritical condition, the core and the Reactor Coolant System are not adversely affected since the combination of thermal power and coolant temperature result in a departure from nucleate boiling ratio greater than the limit value. Thus, no fuel or cladding damage is predicted as a result of this transient.

6.3.5.2 UNCONTROLLED ROD CONTROL CLUSTER ASSEMBLY BANK WITHDRAWAL AT POWER (SEABROOK STATION UFSAR SECTION 15.4.2)

6.3.5.2.1 ACCIDENT DESCRIPTION

The uncontrolled rod cluster control assembly bank withdrawal at power event is defined as the inadvertent addition of reactivity to the core caused by the withdrawal of rod cluster control assembly banks when the core is above the no-load condition. The reactivity insertion resulting from the bank (or banks) withdrawal will cause an increase in core nuclear power and subsequent increase in core heat flux. A rod cluster control assembly bank withdrawal can occur with the reactor subcritical, at hot zero power, or at power. The uncontrolled rod cluster control assembly bank at power event is analyzed for Mode 1 (power operation). The uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low-power condition is considered as an independent event in LAR Section 6.3.5.1.

The event is simulated by modeling a constant rate of reactivity insertion starting at time zero and continuing until a reactor trip occurs. The analysis assumes a spectrum of possible reactivity insertion rates up to a maximum positive reactivity insertion rate greater than that occurring with the simultaneous withdrawal, at maximum speed, of two sequential rod cluster control assembly banks having the maximum differential rod worth.

Unless the transient Reactor Coolant System response to the rod cluster control assembly bank withdrawal event is terminated by manual or automatic action, the power mismatch and resultant temperature rise could eventually result in departure from nucleate boiling and/or fuel centerline melt. Additionally, the increase in Reactor Coolant System temperature caused by this event will increase the pressure, and if left unchecked, could challenge the integrity of the Reactor Coolant System pressure boundary or the Main Steam System pressure boundary.

To avert the core damage that might otherwise result from this event, the reactor protection system is designed to automatically terminate an event before the departure from nucleate boiling ratio falls below the limit value, the fuel rod KW/ft limit is exceeded, the peak pressures exceed their respective limits, or the pressurizer fills. Depending on the initial power level and the rate of reactivity insertion, the reactor may be tripped and the rod cluster control assembly withdrawal terminated by any of the following trip signals:

- Power-range high neutron flux
- Positive flux rate
- Overtemperature ΔT
- Overpower ΔT
- High pressurizer pressure
- High pressurizer water level

6.3.5.2.2 METHOD OF ANALYSIS

The uncontrolled rod cluster control assembly bank withdrawal at power event is analyzed to show that: (1) the integrity of the core is maintained by the Reactor Protection System (the departure from nucleate boiling ratio remains above the safety analysis limit of 1.47 and that the peak core flux remains below 118% ensuring that the fuel rod kW/ft limit is not exceeded) and (2) the peak Reactor Coolant System and Main Steam System pressures remain below 110 percent of the corresponding design limits (2748.5 and 1318.5 psia respectively).

The rod cluster control assembly bank withdrawal at power transient is analyzed with the RETRAN computer program [Reference 6.3-1]. The program simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator relief and safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

To obtain a conservative value for the minimum departure from nucleate boiling ratio, the following analysis assumptions are made:

1. This accident is analyzed with the Revised Thermal Design Procedure [Reference 6.3-8]. Therefore, initial reactor power, pressure, and Reactor Coolant System temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit departure from nucleate boiling ratio.
2. Reactivity coefficients - Two conditions are analyzed:
   - Minimum reactivity feedback - A zero moderator temperature coefficient of reactivity (0 pcm/°F) is assumed at full power. For power levels less than or equal to 70-percent power, a positive moderator temperature coefficient of reactivity (+5 pcm/°F) is conservatively assumed, corresponding to the beginning of core life. A conservatively small (in absolute magnitude) Doppler power coefficient is used in the analysis.
   - Maximum reactivity feedback - A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed.
3. The reactor trip on high neutron flux is actuated at a conservative value of 118 percent of nominal full power. The overtemperature ΔT trip includes all adverse instrumentation and setpoint errors. The delays for trip actuation are assumed to be the maximum values.
4. The rod control cluster assembly trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.
5. A range of reactivity insertion rates from 1 to 110 pcm/sec is examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservative speed (45 inches/minute, which corresponds to 72 steps/minute).

6. Power levels of 10 percent, 60 percent and 100 percent of analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) are considered.
7. The impact of a full-power Reactor Coolant System vessel T_{avg} window was considered for the uncontrolled rod control cluster assembly bank withdrawal at power analysis. A conservative calculation modeling the high end of the Reactor Coolant System vessel T_{avg} window was explicitly analyzed.

6.3.5.2.3 RESULTS

The calculated sequence of events for a transient initiated at full power is shown in LAR Table 6.3.5.2-1. The limiting results calculated for the rod control cluster assembly bank withdrawal at power transient analyzed for the SPU implementation are provided in LAR Table 6.3.5.2-2.

LAR Figures 6.3.5.2-1 through 6.3.5.2-4 show the response of nuclear power, pressurizer pressure, reactor vessel T_{avg}, and departure from nucleate boiling ratio due to a rapid rod control cluster assembly bank withdrawal incident starting from 100-percent power. Reactor trip on high neutron flux occurs shortly after the start of the accident. As this is rapid with respect to the thermal time constants of the plant, small changes in reactor core T_{avg} and pressurizer pressure result, and a large margin to departure from nucleate boiling is maintained.

The response of nuclear power, pressurizer pressure, reactor vessel T_{avg}, and departure from nucleate boiling ratio for a slow rod control cluster assembly bank withdrawal from 100-percent power are shown in LAR Figures 6.3.5.2-5 through 6.3.5.2-8. Reactor trip on overtemperature ΔT occurs after a longer period of time and the rise in temperature is consequently larger than for a rapid rod control cluster assembly bank withdrawal. Again, the minimum departure from nucleate boiling ratio is greater than the limit value.

LAR Figures 6.3.5.2-9, 6.3.5.2-10, and 6.3.5.2-11 show the minimum departure from nucleate boiling ratio as a function of the reactivity insertion rate for minimum and maximum reactivity feedback for the three initial power levels (100 percent, 60 percent, and 10 percent). It can be seen that the high neutron flux and overtemperature ΔT trip functions provide protection over the assumed range of reactivity insertion rates, because the minimum departure from nucleate boiling ratio is never less than the limit value.

In the referenced figures, the shape of the curves of minimum departure from nucleate boiling ratio versus reactivity insertion rate is due both to the reactor core and coolant system transient response and to protection system action in initiating a reactor trip.

Referring to LAR Figure 6.3.5.2-11 for example, note that:

1. For high reactivity insertion rates (that is, between ~110 pcm/second and ~15 pcm/second) when modeling minimum reactivity feedback, reactor trip is initiated by the high neutron flux trip. The neutron flux level in the core rises rapidly for these insertion rates, while core heat flux and coolant temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Therefore, the reactor is tripped prior to a significant increase in the heat flux or core water temperature with

resultant high minimum departure from nucleate boiling ratios during the transient. Within this range, as the reactivity insertion rate decreases, core heat flux and coolant temperatures can remain more nearly in equilibrium with the neutron flux. Therefore, minimum departure from nucleate boiling ratio during the transient decreases with decreasing reactivity insertion rate.

2. With a further decrease in the reactivity insertion rate, the overtemperature ΔT and high neutron flux trips become equally effective in terminating the transient (such as, at a reactivity insertion rate of approximately 15 pcm/second).

   The overtemperature ΔT reactor trip function initiates a reactor trip when the measured ΔT exceeds an overtemperature ΔT setpoint that is based on the measured vessel T_{avg} and pressurizer pressure. It is important to note, however, that the contribution of Reactor Coolant System vessel T_{avg} to the overtemperature ΔT trip function is lead-lag compensated to compensate for the effect of the thermal capacity of the Reactor Coolant System response to power increases.

   For reactivity insertion rates between ~15 pcm/second and ~10 pcm/second, the effectiveness of the overtemperature ΔT trip increases (in terms of increased minimum departure from nucleate boiling ratio). This is due to the fact that, with lower insertion rates, the power increase rate is slower, the rate of rise of Reactor Coolant System vessel T_{avg} is slower, and the system lags and delays become less significant.

3. For reactivity insertion rates of ~10 pcm/second and lower, the rise in Reactor Coolant System temperature is sufficiently high so that there is an increased steam relief through the steam generator safety valves prior to trip. This steam relief acts as an additional heat sink on the Reactor Coolant System and sharply slows the increase of the Reactor Coolant System vessel T_{avg}. This causes the overtemperature ΔT trip setpoint to be reached later with resulting lower minimum departure from nucleate boiling ratios.

6.3.5.2.4 CONCLUSIONS

The results of the uncontrolled rod control cluster assembly bank withdrawal at power transient analysis show that the high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates; that is, the minimum calculated departure from nucleate boiling ratio is always greater than the safety analysis limit value. In addition, the results show that the peak KW/ft is less than the limit and the peak pressure in the Main Steam System does not exceed 110 percent of its design pressure. The peak pressure in the Reactor Coolant System is bounded by the Loss of External Load / Turbine Trip Analysis (LAR Subsection 6.3.3.1).

Thus, all pertinent criteria are met for the uncontrolled rod control cluster assembly bank withdrawal at power transient when assuming the SPU implementation.

6.3.5.3 ROD CLUSTER CONTROL ASSEMBLY MISOPERATION (SYSTEM MALFUNCTION OR OPERATOR ERROR) (SEABROOK STATION UFSAR SECTION 15.4.3)

6.3.5.3.1 ACCIDENT DESCRIPTION

The rod cluster control assembly misalignment accidents include:

- Dropped full length rod cluster control assemblies
- Dropped full length rod cluster control assembly banks
- Statically misaligned full length rod cluster control assemblies
- Withdrawal of a single rod cluster control assembly

Each rod cluster control assembly has a rod position indicator channel which displays the position of the assembly. The displays of assembly positions are grouped for operator convenience. Fully inserted assemblies are further indicated by a rod bottom signal.

Dropped assemblies or assembly banks are detected by:

- Sudden drop in the core power level
- Asymmetric power distribution (as seen on out-of-core neutron detectors or core exit thermocouples)
- Rod bottom signal
- Rod deviation alarm
- Rod position indication

Misaligned assemblies are detected by:

- Asymmetric power distribution (as seen on out-of-core neutron detectors or core exit thermocouples)
- Rod deviation alarm
- Rod position indication

6.3.5.3.2 METHOD OF ANALYSIS

<u>One or More Dropped Rod Cluster Control Assemblies from the Same Group</u>

The LOFTRAN computer code calculates transient system responses for the evaluation of a dropped rod cluster control assembly event. The code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power levels.

Transient Reactor Coolant System statepoints (temperature, pressure, and power) are calculated by LOFTRAN. Nuclear models are used to obtain a hot-channel factor consistent with the primary-system conditions and reactor power. By incorporating the

primary conditions from the transient analysis and the hot-channel factor from the nuclear analysis, it is shown that the departure from nucleate boiling design basis is met using dropped rod limit lines developed with the VIPRE code. The transient response analysis, nuclear peaking factor analysis, and performance of the departure from nucleate boiling design basis confirmation are performed in accordance with approved methodology described in Reference 6.3-9 and in line with the Reference 6.3-8 guidelines. The analysis does not take credit for the power-range negative flux rate reactor trip.

A generic statepoint analysis for this event [Reference 6.3-25], which was performed in 1986 to bound a number of four-loop pressurized water reactors, was evaluated and determined to remain applicable for the SPU. With the generic statepoints being applicable, the effects of the SPU are accounted for when performing the nuclear and departure from nucleate boiling analyses, which are performed on a cycle-specific basis.

Dropped Rod Cluster Control Assembly Bank

A dropped rod cluster control assembly bank results in a symmetric power change in the core. Assumptions made in the methodology [References 6.3-9 and 6.3-25] for the dropped rod cluster control assemblies analysis provide a bounding analysis for the dropped rod cluster control assembly bank.

Statically Misaligned Rod Cluster Control Assembly

Steady-state power distributions are analyzed using the appropriate nuclear physics computer codes. The peaking factors are then compared to peaking factor limits developed using the VIPRE code, which are based on meeting the departure from nucleate boiling ratio design criterion. The following cases are examined in the analysis assuming the reactor is at full power: the worst rod withdrawn with bank D inserted at the insertion limit, the worst rod dropped with bank D inserted at the insertion limit, and the worst rod dropped with all other rods out. It is assumed that the incident occurs at the time in the cycle with maximum predicted peaking factors. This assures a conservative $F_{\Delta H}$ for the misaligned rod cluster control assembly configuration.

Single Rod Cluster Control Assembly Withdrawal

Power distributions within the core are calculated. The peaking factors are then used by VIPRE to calculate the departure from nucleate boiling ratio for the event. The case of the worst rod withdrawn from bank D inserted at the insertion limit, with the reactor initially at full power was analyzed. This incident is assumed to occur at beginning-of-life since this results in the minimum value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

6.3.5.3.3 RESULTS

One or More Dropped Rod Cluster Control Assemblies

Single or multiple dropped rod cluster control assemblies within the same group result in a negative reactivity insertion. The core is not adversely affected during this period

since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal will re-establish power. Partially dropped rod cluster control assembly results are bounded by the fully dropped rod cluster control assembly results.

Following a dropped rod event in manual rod control, the plant will establish a new equilibrium condition. Without control system interaction, a new equilibrium is achieved at a reduced power level and reduced primary temperature. Therefore, the automatic rod control mode of operation is the limiting case.

For a dropped rod cluster control assembly event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller, after which the control system will insert the control bank to restore nominal power. LAR Figures 6.3.5.3-1 through 6.3.5.3-4 show a typical transient response to a dropped rod cluster control assembly (or rod cluster control assemblies) event with the reactor in automatic rod control. In all cases, the minimum departure from nucleate boiling ratio remains above the limit value.

Following plant stabilization, the operator may manually retrieve the rod cluster control assembly(s) by following approved operating procedures.

Dropped Rod Control Cluster Assembly Bank

A dropped rod control cluster assembly bank results in a large negative reactivity insertion. The core is not adversely affected during the insertion period, since power is decreasing rapidly. The transient will proceed similar to that described in the previous "One or More Dropped Rod Control Cluster Assemblies" section. In most cases, the negative reactivity worth of a dropped rod control cluster assembly bank is greater than the available positive reactivity worth associated with the automatic withdrawal of control bank D from its full power insertion limit. However, in the case of a relatively low worth dropped rod control cluster assembly bank, such as Shutdown Bank A, the available positive reactivity worth from automatic control bank D withdrawal may exceed the negative reactivity worth of the dropped bank by a small amount. Therefore, a power overshoot may still occur in the case of a dropped rod control cluster assembly bank, due to the combined effects of both automatic withdrawal of bank D and moderator temperature reactivity feedback. However, the magnitude of the possible power overshoot is smaller with a dropped rod control cluster assembly bank, than it is with single or multiple dropped rod control cluster assemblies, due to the greater worth of the entire dropped bank, when compared to the available bank D worth. In addition, the power distribution associated with a dropped rod control cluster assembly bank is symmetric, resulting in lower peaking factors, when compared to the asymmetric power distributions associated with single or multiple dropped rod control cluster assemblies. Therefore, the minimum departure from nucleate boiling ratio for a dropped rod control cluster assembly bank event is bounded by the departure from nucleate boiling ratio associated with single or multiple dropped rod control cluster assemblies. Following plant stabilization, normal procedures are followed.

Statically Misaligned Rod Control Cluster Assembly

The most severe rod control cluster assembly misalignment situations with respect to departure from nucleate boiling at significant power levels are associated with cases in which one rod control cluster assembly is fully inserted with either all rods out or bank D at the insertion limit, or where bank D is inserted to the insertion limit and one rod control cluster assembly is fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the transient approaches the postulated conditions.

The insertion limits in the Technical Specifications may vary from time to time, depending on several limiting criteria. The full-power insertion limits on control bank D are to be above that position which meets the minimum departure from nucleate boiling ratio and peaking factors. The full-power insertion limit is usually dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For the rod control cluster assembly misalignment case with one rod control cluster assembly fully inserted (with either all rods out or bank D at the insertion limit), the departure from nucleate boiling ratio does not fall below the limit value. The analysis for this case assumes that the initial reactor power, Reactor Coolant System pressure, and Reactor Coolant System temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned rod control cluster assembly.

Calculations have not been performed specifically for rod control cluster assemblies missing from other control banks, which are permitted to be either fully or partially inserted at part power conditions. However, it has been determined on a generic basis that the increase in radial peaking factor necessary to reach the departure from nucleate boiling ratio limit at reduced power conditions, is greater than the credible increase in radial peaking factors associated with reduced thermal power levels and deeper permitted control bank insertion. Therefore, the full power case discussed above with bank D at the insertion limit is more limiting than a credible part power rod control cluster assembly misalignment scenario involving rods at the insertion limit.

For the rod control cluster assembly misalignment case with bank D inserted to the full-power insertion limit and one rod control cluster assembly fully withdrawn, the departure from nucleate boiling ratio does not fall below the limit value. The analysis for this case assumes that the initial reactor power, Reactor Coolant System pressure, and Reactor Coolant System temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned rod control cluster assembly.

Departure from nucleate boiling does not occur for the rod control cluster assembly misalignment incident. Therefore, there is 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 rod control cluster assembly and the design axial power distribution. The resulting linear heat generation rate is well below that which would cause fuel melting.

After identifying a rod control cluster assembly group misalignment condition, the operator must take action as required by the plant Technical Specifications and operating procedures.

Single Rod Control Cluster Assembly Withdrawal

For the single rod withdrawal event, two cases have been considered as follows:

1. If the reactor is in the manual control mode, continuous withdrawal of a single rod control cluster assembly results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the withdrawing rod control cluster assembly. In terms of the overall system response, this case is similar to a Statically Misaligned rod control cluster assembly; however, the increased local power peaking in the area of the withdrawn rod control cluster assembly may result in lower minimum departure from nucleate boiling ratios than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn rod control cluster assembly, automatic reactor trip may not occur sufficiently fast to prevent the minimum core departure from nucleate boiling ratio from falling below the limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature ΔT trip would be expected to trip the plant shows that an upper limit for the number of rods with a departure from nucleate boiling ratio less than the limit value is 5 percent. Rod ejection accident, LAR Subsection 6.3.5.7, bounds this event.

2. If the reactor is in the automatic control mode, the multiple failures that result in the withdrawal of a single rod control cluster assembly will result in the immobility of the other rod control cluster assemblies in the controlling bank. The transient will then proceed in the same manner as Case 1 described above.

For such cases as above, a reactor trip will ultimately ensue, although not sufficiently fast in all instances to prevent a minimum departure from nucleate boiling ratio in the core of less than the limit value. Following reactor trip, normal shutdown procedures are followed.

6.3.5.3.4 CONCLUSIONS

The evaluation of the generic statepoints that were obtained using the methodology in Reference 6.3-9, for cases of dropped rod control cluster assemblies or dropped banks encompassing all possible dropped rod worths delineated in Reference 6.3-9, concluded that the minimum departure from nucleate boiling ratio remains above the safety analysis limit value. For all cases of a single rod control cluster assembly fully inserted, or bank D inserted to the rod insertion limit and a single rod control cluster assembly in that bank fully withdrawn (static misalignment), the minimum departure from nucleate boiling ratio remains above the limit value. Therefore, the departure from nucleate boiling design criterion is met and the rod control cluster assembly misalignments do not result in core damage given implementation of the SPU. For the case of the accidental withdrawal of a single rod control cluster assembly, with the reactor in the automatic or manual control mode and initially operating at full power with

bank D at the insertion limit, an upper bound of the number of fuel rods experiencing departure from nucleate boiling is 5 percent of the total number of fuel rods in the core.

6.3.5.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP AT AN INCORRECT TEMPERATURE (SEABROOK STATION UFSAR SECTION 15.4.4)

Three-loop operation is not permitted at Seabrook Station per Technical Specifications [Reference 6.3-5]. Therefore, no analysis was performed for this event.

6.3.5.5 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT RESULTS IN A DECREASE IN BORON CONCENTRATION IN THE REACTOR COOLANT (SEABROOK STATION UFSAR SECTION 15.4.6)

6.3.5.5.1 ACCIDENT DESCRIPTION

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

The inadvertent opening of the reactor makeup water control valve in conjunction with a failure in the blend system permitting 0 ppm water to flow from the discharge of a single reactor makeup water pump to the charging pump suction is considered the limiting American Nuclear Society Condition II uncontrolled boron dilution event for all modes of operation. In order for makeup water to be added to the Reactor Coolant System at pressure, at least one charging pump must be running in addition to a reactor makeup water pump.

Information on the status of the reactor makeup water is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the Chemical and Volume Control System. Alarms are actuated to warn the operator that boric acid or demineralized water flowrates deviate from preset values as a result of system malfunction.

The inadvertent dilution from this source can readily be terminated by closing the reactor makeup control valve or stopping the reactor makeup water pump.

The rate of unborated makeup water addition to the Reactor Coolant System for this worst-case scenario is limited to the discharge flow capacity of a single reactor makeup water pump to the Chemical and Volume Control System boric acid blender (150 gpm).

An additional source of unborated water which can dilute the reactor coolant is the Boron Thermal Regeneration System. Borated Reactor Coolant System water is depleted of boron as it passes through the Boron Thermal Regeneration System.

The Boron Thermal Regeneration System is capable of supplying dilutent at a rate comparable to that of one reactor makeup water pump. However, water from the Boron Thermal Regeneration System is passed to the Chemical and Volume Control System volume control tank where it mixes with water maintained at or nearly equal to the Reactor Coolant System boron concentration. Because of the size of the volume control tank and the mixing of the Boron Thermal Regeneration System dilutent with water in the volume control tank, inadvertent operation of the Boron Thermal Regeneration System is capable of creating only a mild boron dilution transient, which is bounded by the limiting scenario discussed above. The Boron Thermal Regeneration System is excluded as a source of unborated water during refueling, cold shutdown, and hot shutdown since Technical Specifications require the Boron Thermal Regeneration System be rendered inoperable in these modes.

Regardless of the cause of a dilution event, numerous alarms and indications including a Shutdown Monitor System alarm will alert the operator to a potential loss of shutdown margin. The Shutdown Monitor System augments the source range nuclear instrumentation by monitoring for statistically significant increases in the excore neutron flux, as an indication of a potential return to criticality. Specifically, when the neutron count rate increases by more than a preset ratio, an alarm is generated.

The uncontrolled boron dilution event is classified as an American Nuclear Society Condition II incident (a fault of moderate frequency).

6.3.5.5.2 METHOD OF ANALYSIS

Boron dilutions during refueling, cold shutdown, hot shutdown, hot standby, startup, and power operation are considered in this analysis.

The analyses are performed to identify the amount of time available for operator or automatic mitigation of the boron dilution event prior to the complete loss of plant shutdown margin. The acceptance criterion for refueling is that the time available for operator or automatic mitigation of the boron dilution event prior to the complete loss of plant shutdown margin must be greater than 30 minutes; for all other modes of operation the time available for operator or automatic mitigation of the boron dilution event prior to the complete loss of plant shutdown margin must be greater than 15 minutes.

Dilution during Refueling

The following conditions are assumed for an uncontrolled boron dilution during refueling:

- The maximum flow rate of unborated water that can be delivered to the Reactor Coolant System during refueling is assumed to be 150 gpm.
- A minimum Reactor Coolant System water volume of 3395 ft^3 is assumed, which includes the reactor vessel (excluding the upper head region), one hot leg up to the

residual heat removal connection, two cold legs up to the residual heat removal connections and the active volume of the smaller residual heat removal loop.

- The initial boron concentration is assumed to be 2000 ppm. The maximum critical boron concentration during refueling is assumed to be 1600 ppm, with all rods inserted. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

Dilution during Cold Shutdown

The following conditions are assumed for an uncontrolled boron dilution during cold shutdown:

- The maximum flow rate of unborated water that can be delivered to the Reactor Coolant System during cold shutdown is assumed to be 150 gpm.
- The limiting scenario for cold shutdown is the case where the vessel is drained. However, both filled and drained conditions are analyzed.
- The filled vessel Reactor Coolant System volume is 3992 ft^3. The initial boron concentration is assumed to be 1935 ppm. The maximum critical boron concentration during cold shutdown is assumed to be 1700 ppm, with all control rods except the most reactive rod inserted. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.
- The drained vessel Reactor Coolant System volume is 3395 ft^3. The initial boron concentration is assumed to be 2000 ppm. The maximum critical boron concentration during cold shutdown is assumed to be 1700 ppm, with all control rods except the most reactive rod inserted. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

Dilution during Hot Shutdown

The following conditions are assumed for an uncontrolled boron dilution during hot shutdown:

- The maximum flow rate of unborated water that can be delivered to the Reactor Coolant System during hot shutdown is assumed to be 150 gpm.
- A minimum Reactor Coolant System water volume of 3992 ft^3 is assumed.
- The initial boron concentration is assumed to be 1950 ppm. The maximum critical boron concentration during hot shutdown is assumed to be 1700 ppm, with all control rods except the most reactive rod inserted. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

Dilution during Hot Standby

The following conditions are assumed for an uncontrolled boron dilution during hot standby:

- The maximum flow rate of unborated water that can be delivered to the Reactor Coolant System during hot standby is assumed to be 150 gpm.

- A minimum Reactor Coolant System water volume of 8645 ft^3 is assumed.
- The initial boron concentration is assumed to be 1830 ppm. The maximum critical boron concentration during hot shutdown is assumed to be 1700 ppm, with all control rods except the most reactive rod inserted. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

Dilution during Startup

In this mode, the plant is being taken from one long-term mode of operation, hot standby, to another, power. 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.

The following conditions are assumed for an uncontrolled boron dilution during startup:

- The maximum flow rate of unborated water that can be delivered to the Reactor Coolant System during startup is assumed to be 150 gpm.
- A minimum Reactor Coolant System water volume of 9818 ft^3, corresponding to the active Reactor Coolant System volume (not including the pressurizer volume) and accounting for 10-percent steam generator tube plugging.
- The initial boron concentration is assumed to be 1950 ppm, which is a conservative maximum value for the critical concentration at the condition of hot zero power, rods to insertion limits and no Xenon. The critical boron concentration following reactor trip is assumed to be 1750 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive rod control cluster assembly), no Xenon condition. The 200 ppm change from the initial condition note above is a conservative minimum value. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

Dilution during Full Power Operations

The following conditions are assumed for an uncontrolled boron dilution during full-power operation:

- The maximum flow rate of unborated water that can be delivered to the Reactor Coolant System during startup is assumed to be 150 gpm.
- A minimum Reactor Coolant System water volume of 9818 ft^3, corresponding to the active Reactor Coolant System volume (not including the pressurizer volume) accounting for 10-percent steam generator tube plugging.
- The initial boron concentration is assumed to be 1950 ppm, which is a conservative minimum value for hot full power conditions with rods at the insertion limits. The critical boron concentration following reactor trip is assumed to be 1750 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive rod control cluster assembly). The 200 ppm change from the initial to critical conditions is a conservative minimum value. These are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

6.3.5.5.3 RESULTS

Dilution during Refueling

For dilution during refueling, the minimum time required for the shutdown margin to be lost is 37.14 minutes.

Dilution during Cold Shutdown

For dilution during cold shutdown, the minimum time required for the shutdown margin to be lost is 15.69 minutes and 16.65 minutes for filled and drained loops respectively.

Dilution during Hot Shutdown

For dilution during hot shutdown, the minimum time required for the shutdown margin to be lost and the reactor to become critical is 15.32 minutes.

Dilution during Hot Standby

For dilution during hot standby, the minimum time required for the shutdown margin to be lost is 15.78 minutes.

For Dilution during Startup

For dilution during startup, the minimum time required for the shutdown margin to be lost is 38.94 minutes.

For Dilution during Full-Power Operation

With the reactor in automatic control during full power operations, the power and temperature increase from boron dilution results in the insertion of the rod control cluster assemblies and decrease in shutdown margin. Continuation of dilution and rod control cluster assembly insertion would cause the assemblies to reach the minimum limit of the rod insertion monitor. Before reaching this point, however, two alarms are actuated to warn the operator of the accident condition. The first of these, the low insertion limit alarm, alerts the operator to initiate normal boration. The other, the lo-lo insertion limit alarm, alerts the operator to follow emergency boration procedures. The low alarm is set sufficiently above the lo-lo alarm to allow normal boration without the need for emergency procedures. If dilution continues after reaching the lo-lo alarm, it takes approximately 36.9 minutes before the total shutdown margin is lost due to dilution. Adequate time, therefore, is available following the alarms for the operator to determine the cause, isolate the reactor makeup water source, and initiate reboration.

With the reactor in manual control, if no operator action is taken, the power and temperature rise causes the reactor to reach the overtemperature ΔT or high neutron flux trip setpoint. The boron dilution accident in this case is essentially identical to an rod control cluster assembly withdrawal accident at power. There is time available (at least 32 minutes) after a reactor trip for the operator to determine the cause of dilution, isolate the reactor makeup water source, and initiate reboration before the reactor can return to criticality.

6.3.5.5.4 CONCLUSION

The boron dilution analyses demonstrate that a sufficient amount of time is available for operator or automatic mitigation of the boron dilution event prior to the complete loss of plant shutdown margin in all operating modes. Therefore, the SPU is acceptable with respect to the uncontrolled boron dilution event.

6.3.5.6 INADVERTENT LOADING AND OPERATION OF A FUEL ASSEMBLY IN AN IMPROPER POSITION (SEABROOK STATION UFSAR SECTION 15.4.7)

Fuel and core loading errors can arise from the inadvertent loading of one or more fuel assemblies into improper positions, the loading of a fuel rod during manufacture with one or more pellets of the wrong enrichment or the loading of a full fuel assembly during manufacture with pellets of the wrong enrichment. These errors can lead to increased heat fluxes if the fuel is placed in core positions calling for fuel of lesser enrichment.

An error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes which are more peaked than those calculated with the correct enrichments. There is a 5 percent uncertainty margin included in the design value of power peaking factor assumed in the analysis of American Nuclear Society Condition I and Condition II transients. Successful completion of the reload startup physics tests provides assurance that the plant can be operated as designed.

To reduce the probability of core loading errors, strict administrative controls are placed on the entire core loading sequence. Then, using the core loading patterns from the just completed cycle and the ensuing cycle along with the spent fuel pool map, a core loading sequence is developed. The core loading sequence provides the step-by-step instructions necessary to ensure with the desired core configuration is reached. Lastly, as part of the reload process, fuel assembly identification numbers and component types are verified during the reload process. This positive identification along with the multiple independent verification programs utilized during the placement in the reactor vessel provides additional assurance that the fuel is loaded in accordance with the core loading pattern.

The power distortion due to a combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with fixed incore detectors located in about one third of the fuel assemblies in the core. Each fixed incore detector also includes a core exit thermocouple which would also indicate an abnormally high coolant enthalpy rise. Incore flux measurements are taken during the startup subsequent to every refueling operation.

This event is classified as an American Nuclear Society Condition III incident (an infrequent incident) as defined in Seabrook Station UFSAR Subsection 15.0.1.

6.3.5.6.1 CONCLUSIONS

Fuel assembly enrichment errors would be prevented by administrative procedures implemented in fabrication. In the event that a single pin or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced departure

from nucleate boiling ratio and increased fuel and clad temperatures will be limited to the incorrectly loaded pin or pins and perhaps the immediately adjacent pins.

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, the resulting power distribution effects will either be readily detected by the reload startup test program or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

6.3.5.7 SPECTRUM OF ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENTS (SEABROOK STATION UFSAR SECTION 15.4.8)

6.3.5.7.1 ACCIDENT DESCRIPTION

This accident is the result of the extremely unlikely mechanical failure of a control rod drive mechanism pressure housing such that the Reactor Coolant System pressure would eject the rod control cluster assembly and drive shaft. The consequences of this mechanical failure, in addition to being a minor LOCA, may also be a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Certain features in Westinghouse pressurized water reactors are intended to preclude the possibility of a rod ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, along with a thorough quality control (testing) program during assembly, and a nuclear design that lessens the potential ejection worth of control rod assemblies and minimizes the number of assemblies inserted at high power levels.

The mechanical design is discussed in Section 4.6 of the Seabrook Station UFSAR. A failure of the full length control rod mechanism housing, sufficient to allow a control rod to be rapidly ejected from the core, is not considered credible for the following reasons:

- Each control rod drive mechanism housing is completely assembled and shop-tested at 4100 psi.
- The mechanism housings are individually hydrotested as they are installed on the reactor vessel head to the head adapters, and checked during the hydrotest of the completed Reactor Coolant System.
- Stress levels in the mechanism are not affected by system transients at power, or by the thermal movement of the coolant loops. Movements induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME Boiler and Pressure Vessel Code, Section III, for Class 1 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 are 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. Administrative regulations require periodic inspections of those (and other) welds.

Even if a rupture of the control rod mechanism housing is postulated, the operation of a chemical shim plant is such that the severity of an ejected rod is inherently limited. In general, the reactor is operated with control rods inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and groupings of control rod banks are selected during the core nuclear design to lessen the severity of an ejected control rod assembly. Therefore, should a rod control cluster assembly be ejected from the reactor vessel during normal operation, there probably would be no reactivity excursion since most of the control rods are fully withdrawn from the core, or a minor reactivity excursion if an inserted rod control cluster assembly is ejected from its normal position.

However, it may occasionally be desirable to operate with larger control rod insertions. For this reason, rod insertion limits are defined in the Technical Specifications as a function of power level. Operation with the rod control cluster assemblies above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all rod control cluster assemblies is continuously indicated in the control room. An alarm will occur if a bank of rod control cluster assemblies approaches its insertion limit or if one rod control cluster assembly deviates from its bank. There are low and low-low level insertion monitors with visual and audio signals. Operating instructions require boration when receiving either alarm.

If an rod control cluster assembly ejection accident were to occur, a fuel rod thermal transient that could cause a departure from nucleate boiling may occur together with limited fuel damage. The amount of fuel damage that can result from such an accident will be governed mainly by the worth of the ejected rod control cluster assembly and the power distribution attained with the remaining control rod pattern. The transient is limited by the Doppler reactivity effects of the increase in fuel temperature and is terminated by reactor trip actuated by neutron flux signals. It is terminated before conditions are reached that can result in damage to the reactor coolant pressure boundary, or significant disturbances in the core, its support structures or other reactor pressure vessel internals that would impair the capability to cool the core.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler power coefficient. This self limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a rod control cluster assembly ejection accident occur, the following automatic features of the Reactor Protection System are available to terminate the transient:

- The source-range high neutron flux reactor trip is actuated when either of two independent source-range channels indicates a neutron flux level above a pre-selected manually adjustable setpoint. This trip function may be manually bypassed when either intermediate-range flux channel indicates a flux level above a specified

level. It is automatically reinstated when both intermediate-range channels indicate a flux level below a specified level.

- The intermediate-range high neutron flux reactor trip is actuated when either of two independent intermediate-range channels indicates a flux level above a pre-selected manually adjustable setpoint. This trip function may be manually bypassed when two-out-of-four power-range channels give readings above approximately 10 percent of full power and is automatically reinstated when three-out-of-four channels indicate a power below this value.
- The power-range high neutron flux reactor trip (low setting) is actuated when two-out-of-four power-range channels indicate a power level above approximately 25 percent of full power. This trip function may be manually bypassed when two-out-of-four power-range channels indicate a power level above approximately 10 percent of full power and is automatically reinstated when three-out-of-four channels indicate a power level below this value.
- The power-range high neutron flux reactor trip (high setting) is actuated when two-out-of-four power-range channels indicate a power level above a preset setpoint. This trip function is always active when the reactor is at power.
- The high nuclear flux rate reactor trip is actuated when the positive rate of change of neutron flux on two-out-of-four nuclear power-range channels indicates a rate above the preset setpoint. This trip function is always active.

The ultimate acceptance criteria for this event is that any consequential damage to either the core or the Reactor Coolant System must not prevent long-term core cooling, and that the offsite dose consequences must be within the limits of 10 CFR 50.67. To demonstrate compliance with these requirements, it is sufficient to show that the Reactor Coolant System pressure boundary remains intact, and that no fuel dispersal in the coolant, and no gross lattice distortion or severe shock waves will occur in the core. Therefore, the following acceptance criteria are applied to the rod control cluster assembly ejection accident:

- Maximum average fuel pellet enthalpy at the hot spot must remain below 200 cal/g (360 Btu/lbm).
- Peak Reactor Coolant System pressure must remain below that which would cause the stresses in the Reactor Coolant System to exceed the faulted condition stress limits.
- Maximum fuel melting must be limited to the innermost 10 percent of the fuel pellet at the hot spot, independent of the above pellet enthalpy limit.

It should be noted that previously an additional criteria that the average clad temperature at the hot spot must remain below 2700°F and a Zirconium-water reaction at the hot spot must remain below 16% was included. The elimination of this criterion as a basis for evaluating the rod control cluster assembly ejection accident results is consistent with the revised Westinghouse acceptance criteria for this event [Reference 6.3-23].

6.3.5.7.2 METHOD OF ANALYSIS

The calculation of the rod control cluster assembly ejection transient is performed in two stages: a neutron kinetic analysis and a hot-spot fuel heat transfer analysis. The spatial neutron kinetics code TWINKLE [Reference 6.3-3] is used in a 1-D axial kinetics model to calculate the core nuclear power including the various total core feedback effects; that is, Doppler reactivity and moderator reactivity. The average core nuclear power is multiplied by the post-ejection hot-channel factor, and the fuel enthalpy and temperature transients at the hot spot are calculated with the detailed fuel and cladding transient heat transfer computer code, FACTRAN [Reference 6.3-13]. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient. Additional details of the methodology are provided in WCAP-7588 [Reference 6.3-14].

The overpressurization of the Reactor Coolant System and number of rods in departure from nucleate boiling, as a result of a postulated ejected rod, have both been analyzed on a generic basis for Westinghouse pressurized water reactors as detailed in Reference 6.3-14.

If the safety limits for fuel damage are not exceeded, there is little likelihood of fuel dispersal into the coolant or a sudden pressure increase from thermal-to-kinetic energy conversion. The pressure surge for this analysis can, therefore, be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

A detailed calculation of the pressure surge for an ejection worth of one dollar at beginning of life, hot full power, indicates that the peak pressure does not exceed that which would cause stresses in the Reactor Coolant System to exceed their faulted condition stress limits. Since the severity of the Seabrook Station analysis does not exceed this worst-case analysis, the rod control cluster assembly ejection accident will not result in an excessive pressure rise or further damage to the Reactor Coolant System.

Reference 6.3-14 also documents a detailed three-dimensional calculation, which demonstrates an upper limit to the number of rods-in- departure from nucleate boiling for the rod control cluster assembly ejection accident as 10 percent. Since the severity of the Seabrook Station analysis does not exceed this worst-case analysis, the maximum number of rods in departure from nucleate boiling following an rod control cluster assembly ejection will be less than 10 percent, which is well within the 15 percent used in the radiological dose evaluation. The most limiting break size resulting from a rod control cluster assembly ejection will not be sufficient to uncover the core or cause departure from nucleate boiling at a later time. Since the maximum number of fuel rods experiencing departure from nucleate boiling is limited to 15 percent, the fission product release will not exceed the limits of 10 CFR 50.67.

In calculating the nuclear power and hot-spot fuel rod transients following rod control cluster assembly ejection, the following conservative assumptions are made:

1. The analysis assumes uncertainties of 6.0°F in nominal vessel T_{avg} and 50 psi in nominal pressurizer pressure.
2. A minimum value for the delayed neutron fraction for beginning of life and end of life conditions is assumed, which increases the rate at which the nuclear power increases following rod control cluster assembly ejection.
3. A minimum value of the Doppler power defect is assumed, which conservatively results in the maximum amount of energy deposited in the fuel following rod control cluster assembly ejection. A minimum value of the moderator feedback is also assumed. A positive moderator temperature coefficient is assumed for the beginning of life, zero-power case.
4. Maximum values of ejected rod control cluster assembly worth and post-ejection total hot-channel factors are assumed for all cases considered. These parameters are calculated using standard nuclear design codes for the maximum allowed bank insertion at a given power level as determined by the rod insertion limits. No credit is taken for the flux flattening effects of reactivity feedback.
5. The start of rod motion occurs 0.50 seconds after the high neutron flux trip point is reached.

6.3.5.7.3 RESULTS

LAR Figures 6.3.5.7-1 through 6.3.5.7-8 present the nuclear power and hot-spot fuel rod thermal transients for the rod control cluster assembly ejection cases analyzed. The transient results of the analysis are summarized in LAR Table 6.3.5.7-1. A time sequence of events is provided in LAR Table 6.3.5.7-2. For all cases, the maximum fuel pellet enthalpy remained below 200 cal/g. For the hot full power cases, the peak hot-spot fuel centerline temperature reached the fuel melting temperature (4900°F at beginning of life and 4800°F at end of life). However, melting was restricted to less than 10 percent of the pellet. For the hot zero power cases, no fuel melting was predicted.

6.3.5.7.4 CONCLUSIONS

The analysis performed has demonstrated that, for the rod control cluster assembly ejection event, the fuel thermal criteria are not exceeded. In addition, the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits. Also, the upper limit to the number of rods-in-departure from nucleate boiling is 10 percent, which will not result in fission product releases in excess of the limits of 10 CFR 50.67. Consequently, all applicable acceptance criteria are met.

TABLE 6.3.5.1-1
ASSUMPTIONS AND RESULTS
UNCONTROLLED ROD CONTROL CLUSTER ASSEMBLY WITHDRAWAL FROM A SUBCRITICAL CONDITION

Initial power level, %	0	
Reactivity insertion rate, pcm/sec	75	
Delayed neutron fraction	0.0075	
Doppler power defect, pcm	900	
Initial moderator temperature coefficient	+5 pcm/°F	
Trip reactivity, % Δk	1.0	
Hot channel factor	6.64	
Number of reactor coolant pumps operating	2	
Results		
	Calculated Value	**Limit**
Peak fuel centerline temperature, °F	2536	4800
Peak fuel average temperature, °F	2071	4800
Below the first mixing vane grid: (W-3 Correlation)		
Minimum departure from nucleate boiling ratio (Thimble Cell)	1.34	1.30
Minimum departure from nucleate boiling ratio (Typical Cell)	1.46	1.30
Above the first mixing vane grid: (WRB-2 Correlation)		
Minimum departure from nucleate boiling ratio (Thimble Cell)	1.47	1.17
Minimum departure from nucleate boiling ratio (Typical Cell)	1.45	1.17

TABLE 6.3.5.1-2
SEQUENCE OF EVENTS
UNCONTROLLED ROD CONTROL CLUSTER ASSEMBLY WITHDRAWAL FROM A SUBCRITICAL CONDITION

Event	Time (seconds)
Initiation of uncontrolled rod control cluster assembly bank withdrawal	0
Power range high neutron flux low setpoint reached	10.4
Peak nuclear power occurs	10.6
Rod motion begins	10.9
Peak heat flux occurs	12.6
Minimum departure from nucleate boiling ratio occurs	12.6
Peak cladding temperature occurs	12.9
Peak fuel average temperature occurs	13.1
Peak fuel centerline temperature occurs	14.0

TABLE 6.3.5.2-1
TIME SEQUENCE OF EVENTS FOR
UNCONTROLLED ROD CONTROL CLUSTER ASSEMBLY WITHDRAWAL AT POWER
(MAXIMUM NOMINAL REACTOR COOLANT SYSTEM T_{avg}; MINIMUM FEEDBACK)

Event	Time (Seconds)
Case A:	
Initiation of uncontrolled rod control cluster assembly withdrawal at full power with minimum reactivity feedback (75 pcm/sec)	0
Power-range high neutron flux high trip point reached	1.9
Rods begin to fall into core	2.4
Minimum departure from nucleate boiling ratio occurs	2.8
Case B:	
Initiation of uncontrolled rod control cluster assembly withdrawal at full power with minimum reactivity feedback (1 pcm/sec)	0
Overtemperature ΔT reactor trip signal initiated	78.9
Rods begin to fall into core	80.9
Minimum departure from nucleate boiling ratio occurs	81.0

TABLE 6.3.5.2-2
LIMITING RESULTS FOR
ROD CONTROL CLUSTER ASSEMBLY BANK WITHDRAWAL AT POWER TRANSIENT

Criterion	Limiting Value	Analysis Limit	Case
Departure from nucleate boiling ratio	1.54	1.47	10% power, minimum reactivity feedback 21 pcm/second reactivity insertion rate
Core heat flux (fraction of nominal)	1.17	1.18	100% power, maximum reactivity feedback 50 pcm/second reactivity insertion rate
Main Steam System pressure (psia)	1281	1318.5	10% power, minimum reactivity feedback 21 pcm/second reactivity insertion rate

TABLE 6.3.5.7-1
ASSUMPTIONS AND RESULTS
ROD CONTROL CLUSTER ASSEMBLY EJECTION

Beginning of Cycle	Full Power	Zero Power
Initial power level, %	100	0
Ejected rod control cluster assembly worth, % Δk	0.25	0.78
Delayed neutron fraction	0.0054	0.0054
Doppler power defect, % Δk	0.900	0.900
Feedback reactivity weighting	1.355	2.081
Trip reactivity, % Δk	4.0	2.0
F_Q before ejection	2.5	N/A
F_Q after ejection	6.0	11.5
Number of reactor coolant pumps operating	4	2
Maximum fuel pellet enthalpy, cal/g	163.7	140.7
Maximum fuel melted, %	0.31	None
End of Cycle	**Full Power**	**Zero Power**
Initial power level, %	100	0
Ejected rod control cluster assembly worth, % Δk	0.25	0.85
Delayed neutron fraction	0.0044	0.0044
Doppler power defect, % Δk	0.900	0.900
Feedback reactivity weighting	1.486	3.765
Trip reactivity, % Δk	4.0	2.0
F_Q before ejection	2.5	N/A
F_Q after ejection	7.0	26.0
Number of reactor coolant pumps operating	4	2
Maximum fuel pellet enthalpy, cal/g	163.8	149.4
Maximum fuel melted, %	1.79	None

TABLE 6.3.5.7-2
SEQUENCE OF EVENTS
ROD CONTROL CLUSTER ASSEMBLY EJECTION

Beginning of Cycle - Hot Zero Power	**Time (seconds)**
Rod control cluster assembly ejection occurs	0.000
High neutron flux setpoint (low setting) is reached	0.274
Peak nuclear power occurs	0.332
Rods begin to fall into the core	0.774
Peak cladding average temperature occurs	2.150
Peak heat flux occurs	2.156
Peak fuel average temperature occurs	2.321
Beginning of Cycle - Hot Full Power	**Time (seconds)**
Rod control cluster assembly ejection occurs	0.000
High neutron flux setpoint (high setting) is reached	0.040
Peak nuclear power occurs	0.135
Rods begin to fall into the core	0.540
Peak fuel average temperature occurs	2.104
Peak cladding average temperature occurs	2.152
Peak heat flux occurs	2.164
End of Cycle - Hot Zero Power	**Time (seconds)**
Rod control cluster assembly ejection occurs	0.000
High neutron flux setpoint (low setting) is reached	0.189
Peak nuclear power occurs	0.224
Rods begin to fall into the core	0.689
Peak cladding average temperature occurs	1.510
Peak heat flux occurs	1.514
Peak fuel average temperature occurs	1.722
End of Cycle - Hot Full Power	**Time (seconds)**
Rod control cluster assembly ejection occurs	0.000
High neutron flux setpoint (high setting) is reached	0.035
Peak nuclear power occurs	0.130
Rods begin to fall into the core	0.535
Peak fuel average temperature occurs	2.142
Peak cladding average temperature occurs	2.184
Peak heat flux occurs	2.194

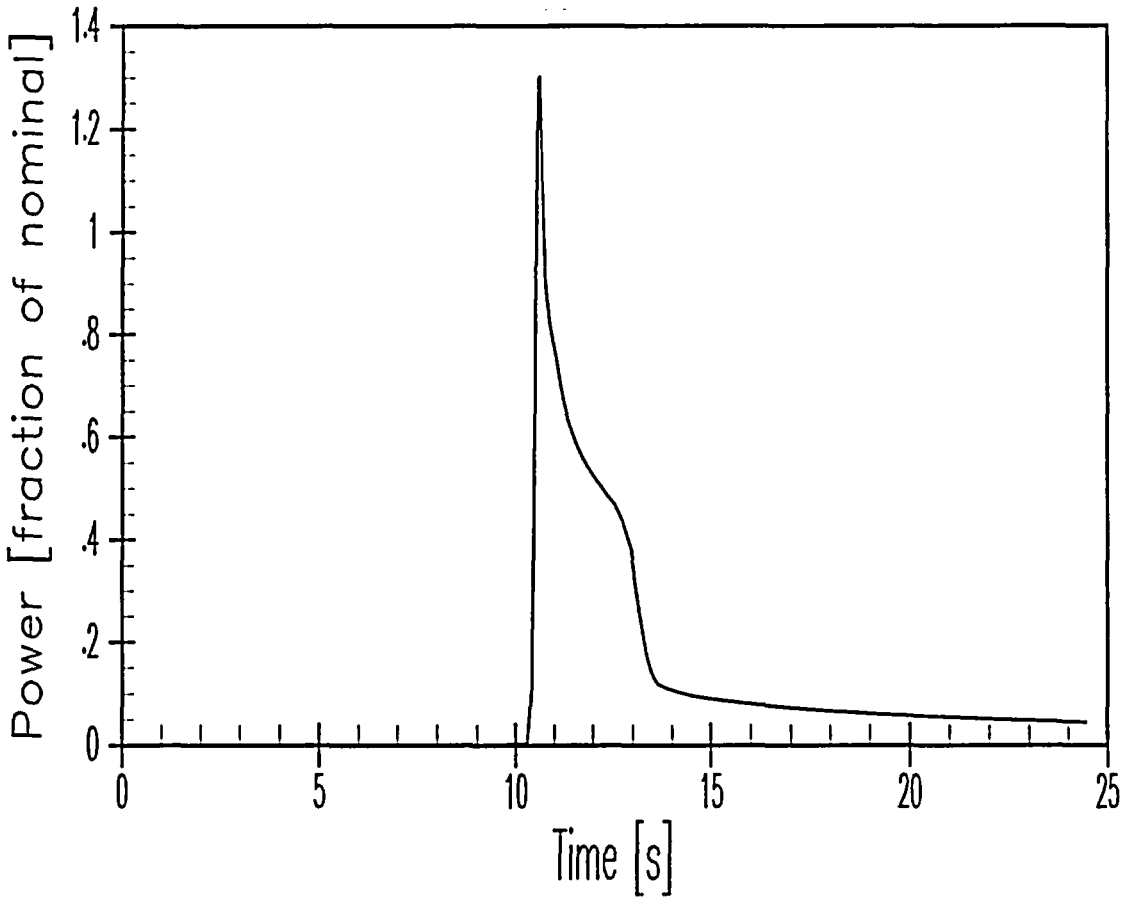


Figure 6.3.5.1-1
Uncontrolled Rod Control Cluster Assembly Withdrawal from a Subcritical Condition
Reactor Power versus Time

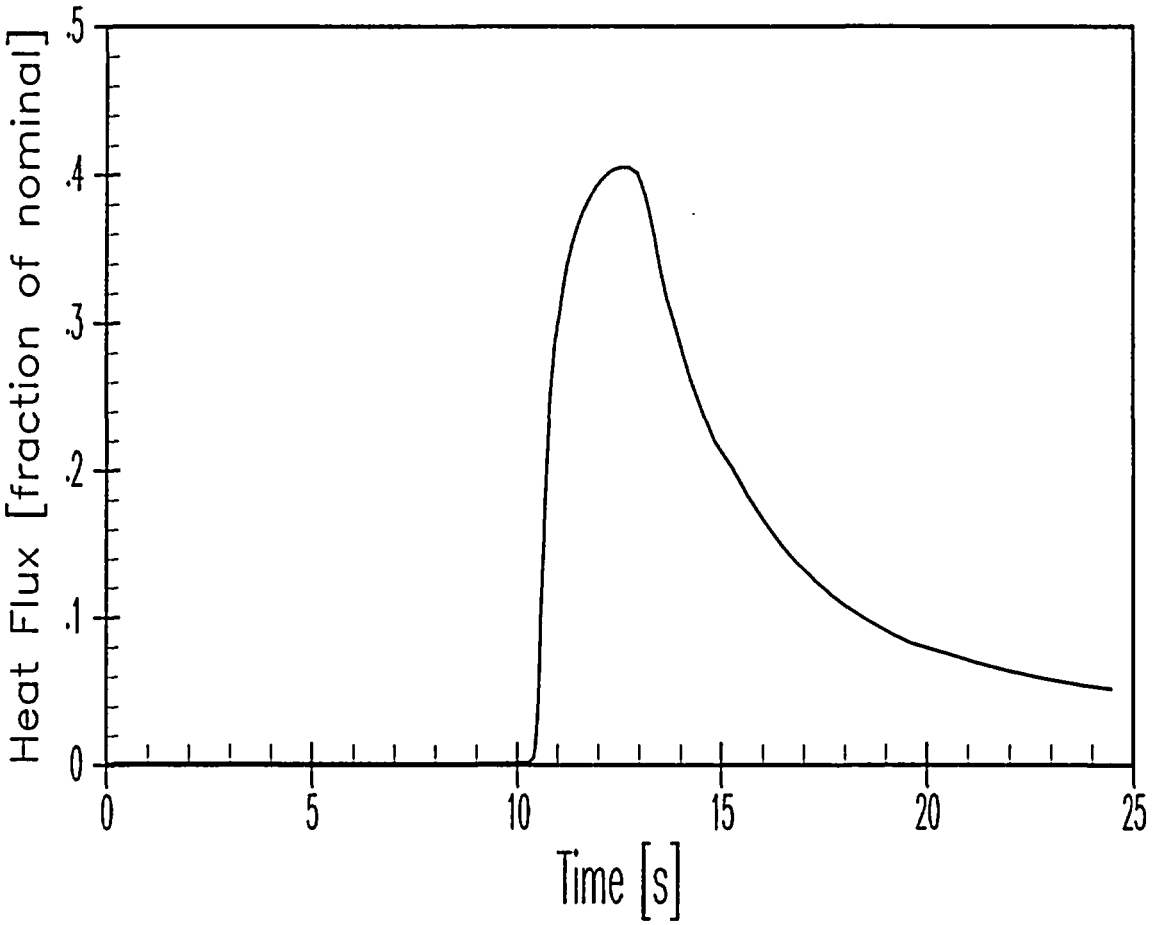


Figure 6.3.5.1-2
Uncontrolled Rod Control Cluster Assembly Withdrawal from a Subcritical Condition
Heat Flux versus Time

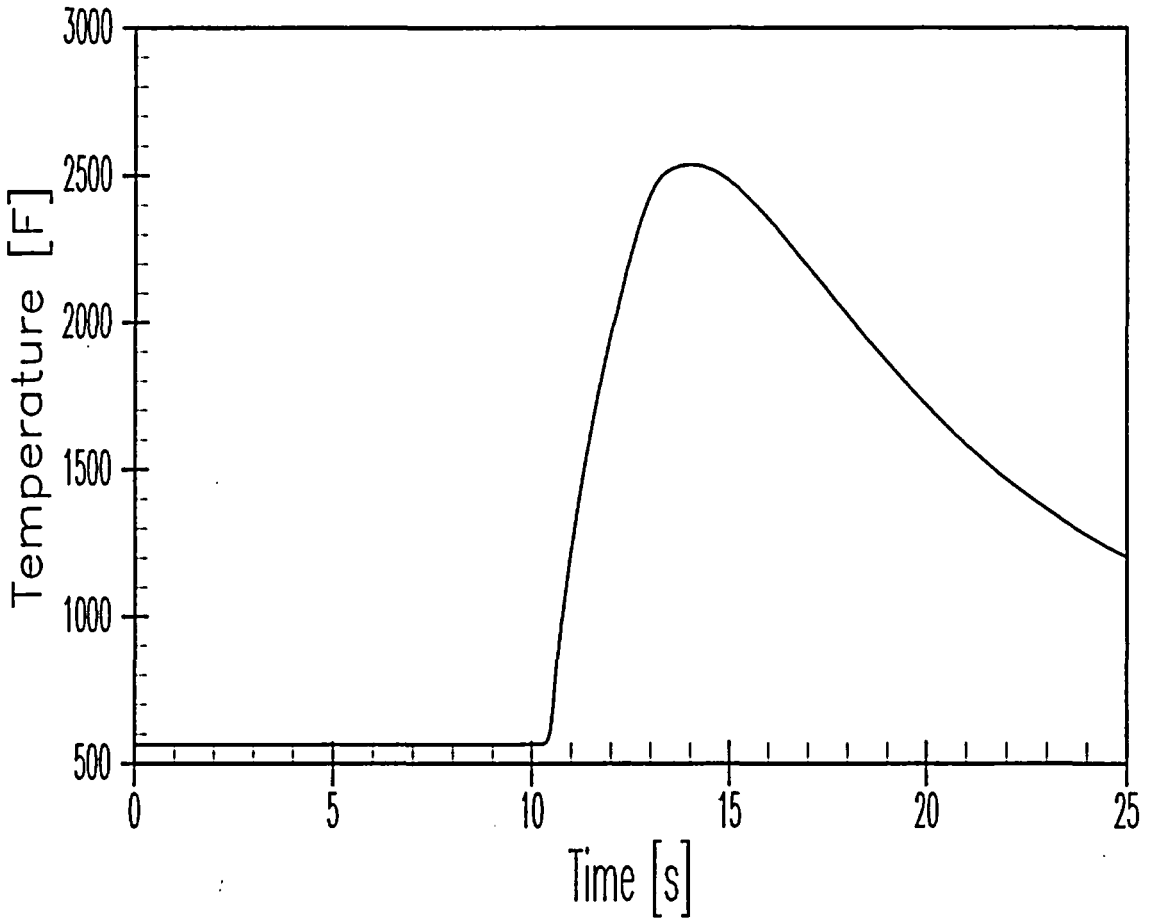


Figure 6.3.5.1-3
Uncontrolled Rod Control Cluster Assembly Withdrawal from a Subcritical Condition
Hot-Spot Fuel Centerline Temperature versus Time

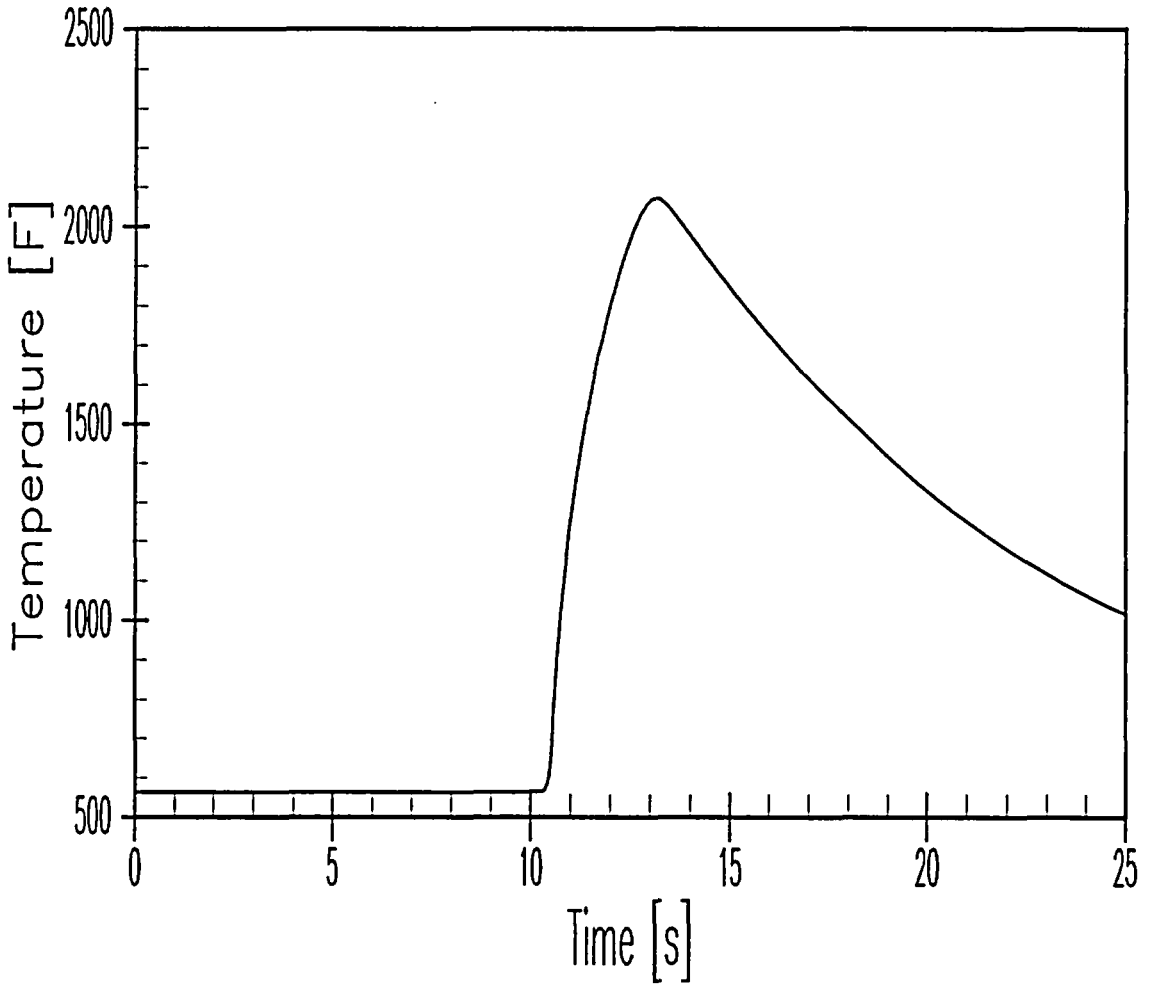


Figure 6.3.5.1-4
Uncontrolled Rod Control Cluster Assembly Withdrawal from a Subcritical Condition
Hot-Spot Fuel Average Temperature versus Time

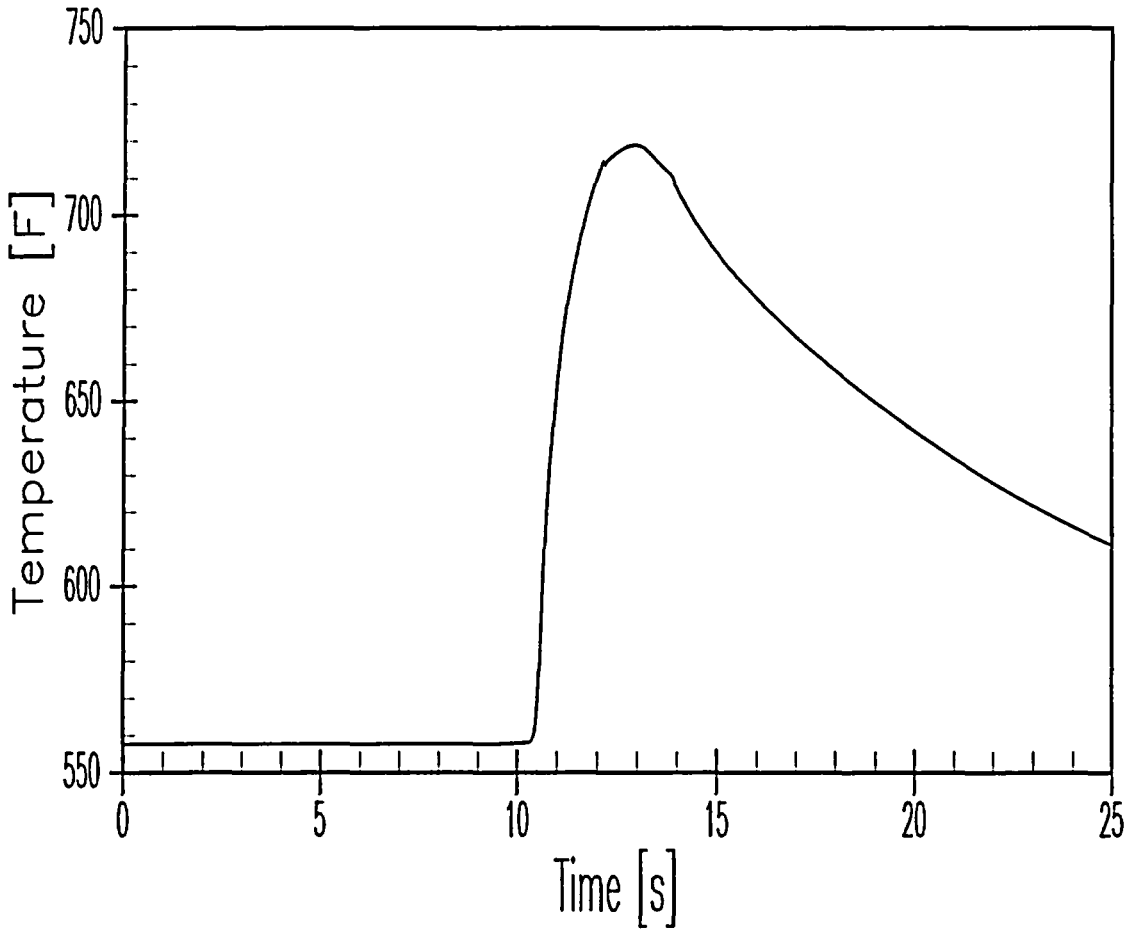


Figure 6.3.5.1-5
Uncontrolled Rod Control Cluster Assembly Withdrawal from a Subcritical Condition
Hot-Spot Cladding Temperature versus Time

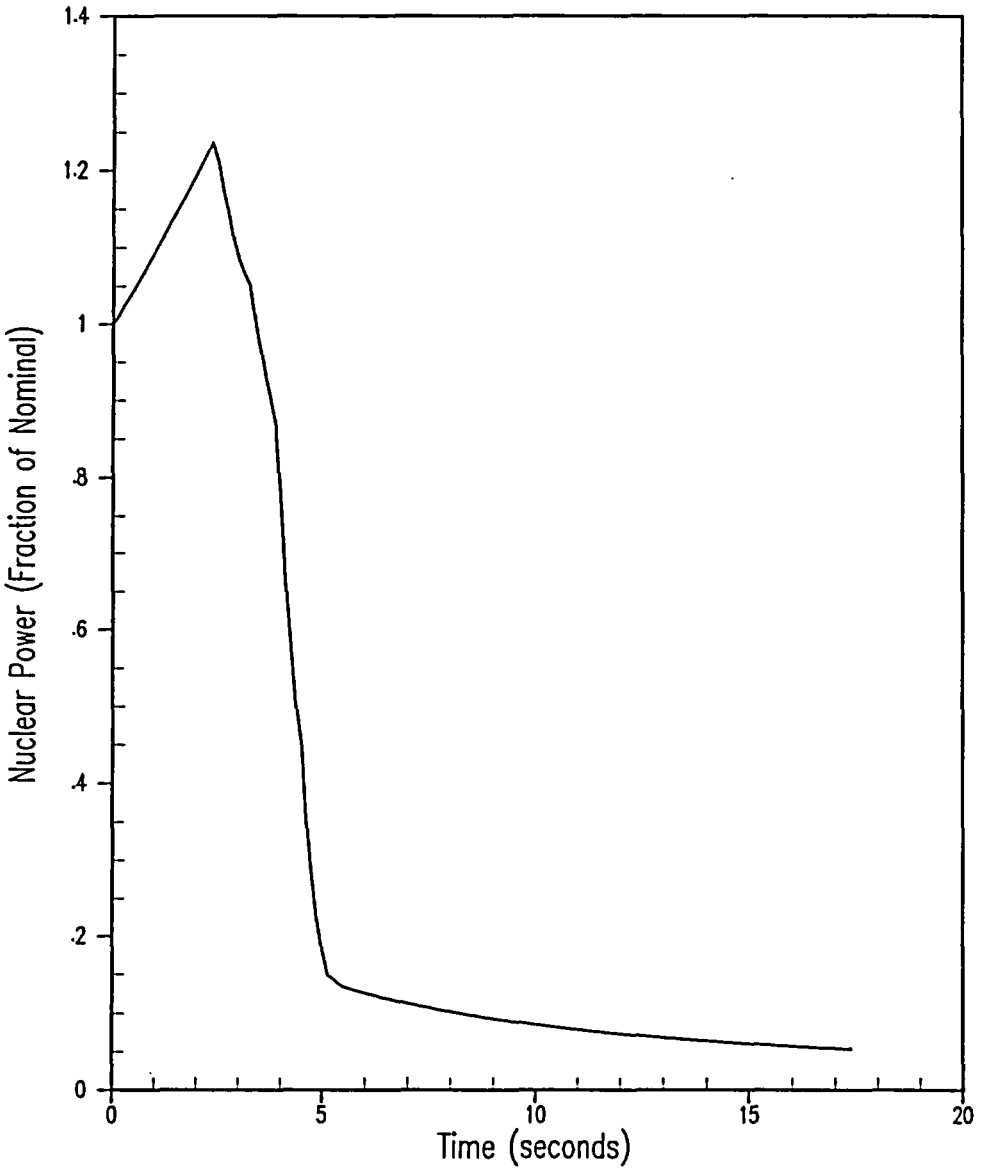


Figure 6.3.5.2-1
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (75 pcm/sec – Full Power) Power-Range High Neutron Flux Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

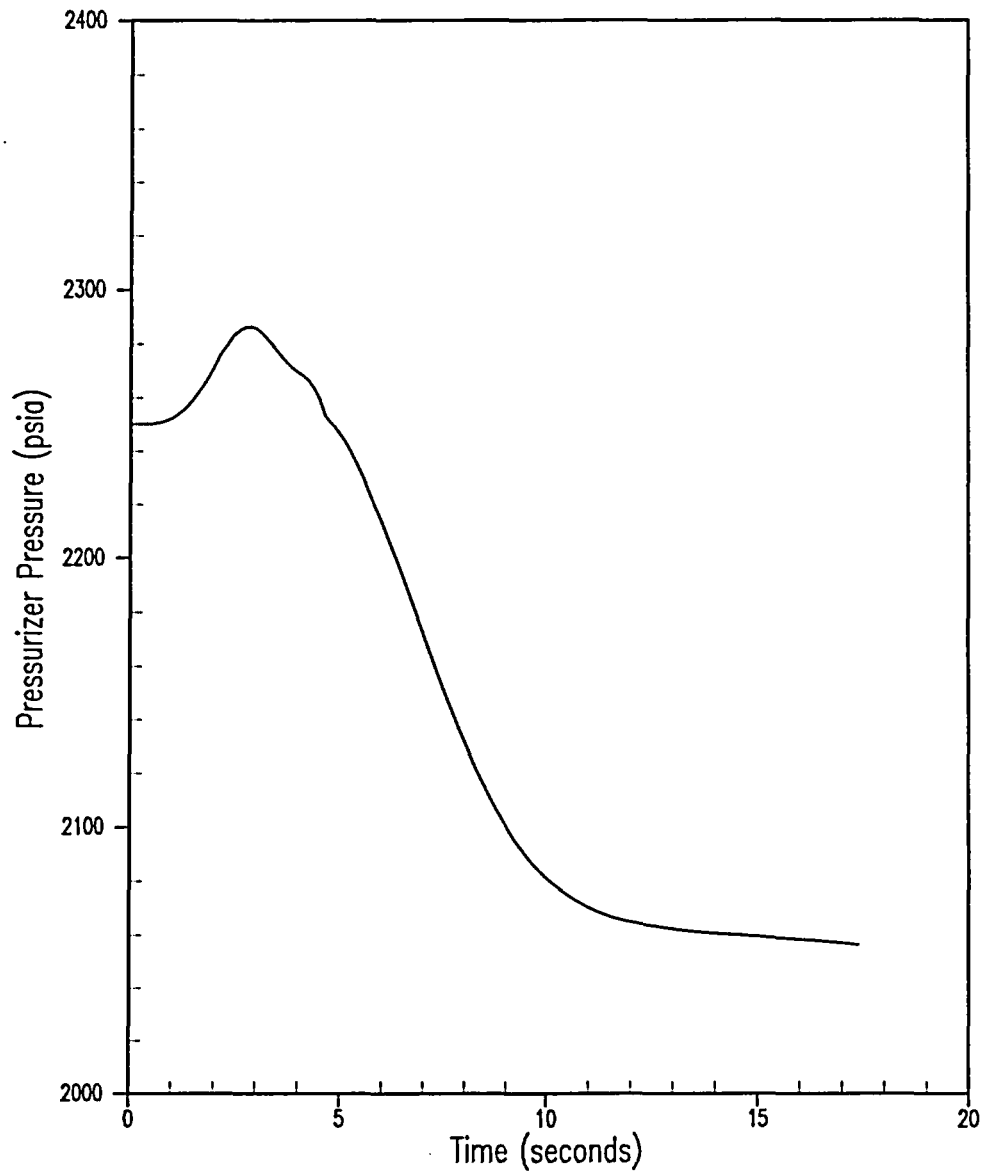


Figure 6.3.5.2-2
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (75 pcm/sec - Full Power) Power-Range High Neutron Flux Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

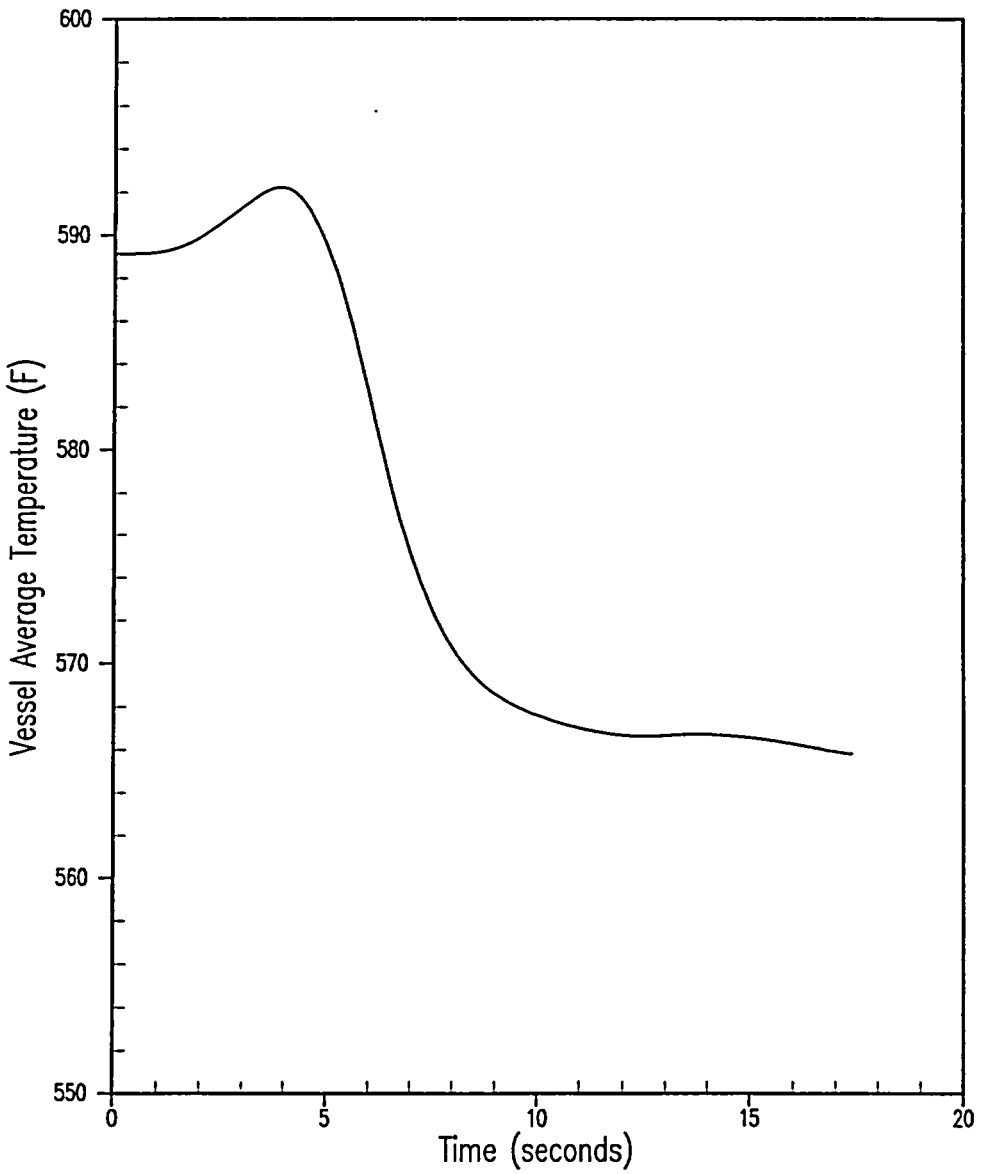


Figure 6.3.5.2-3
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (75 pcm/sec – Full Power) Power-Range High Neutron Flux Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

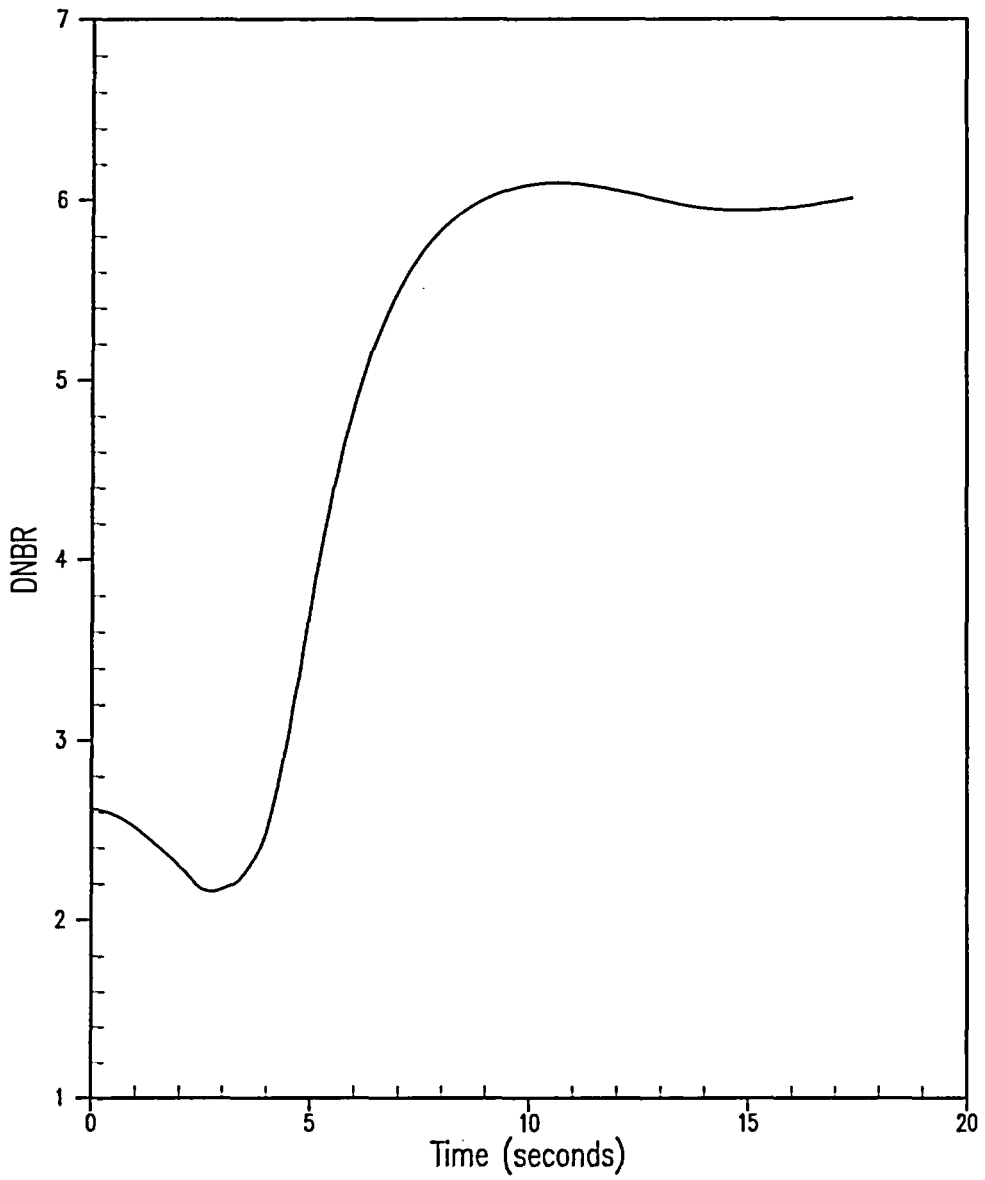


Figure 6.3.5.2-4
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (75 pcm/sec - Full Power) Power-Range High Neutron Flux Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

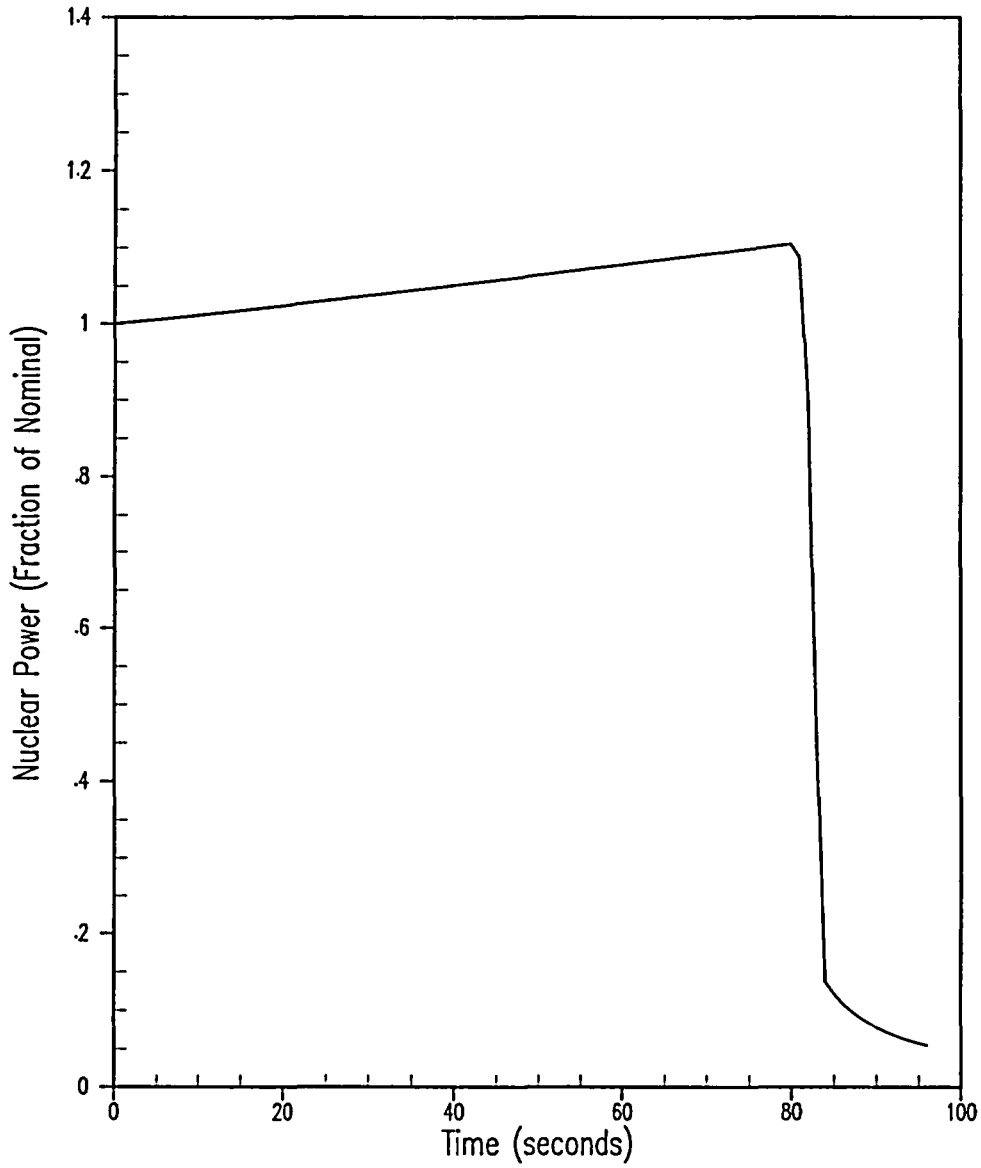


Figure 6.3.5.2-5
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power
(1 pcm/sec - 100% Power) OTΔT Trip, Maximum
Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

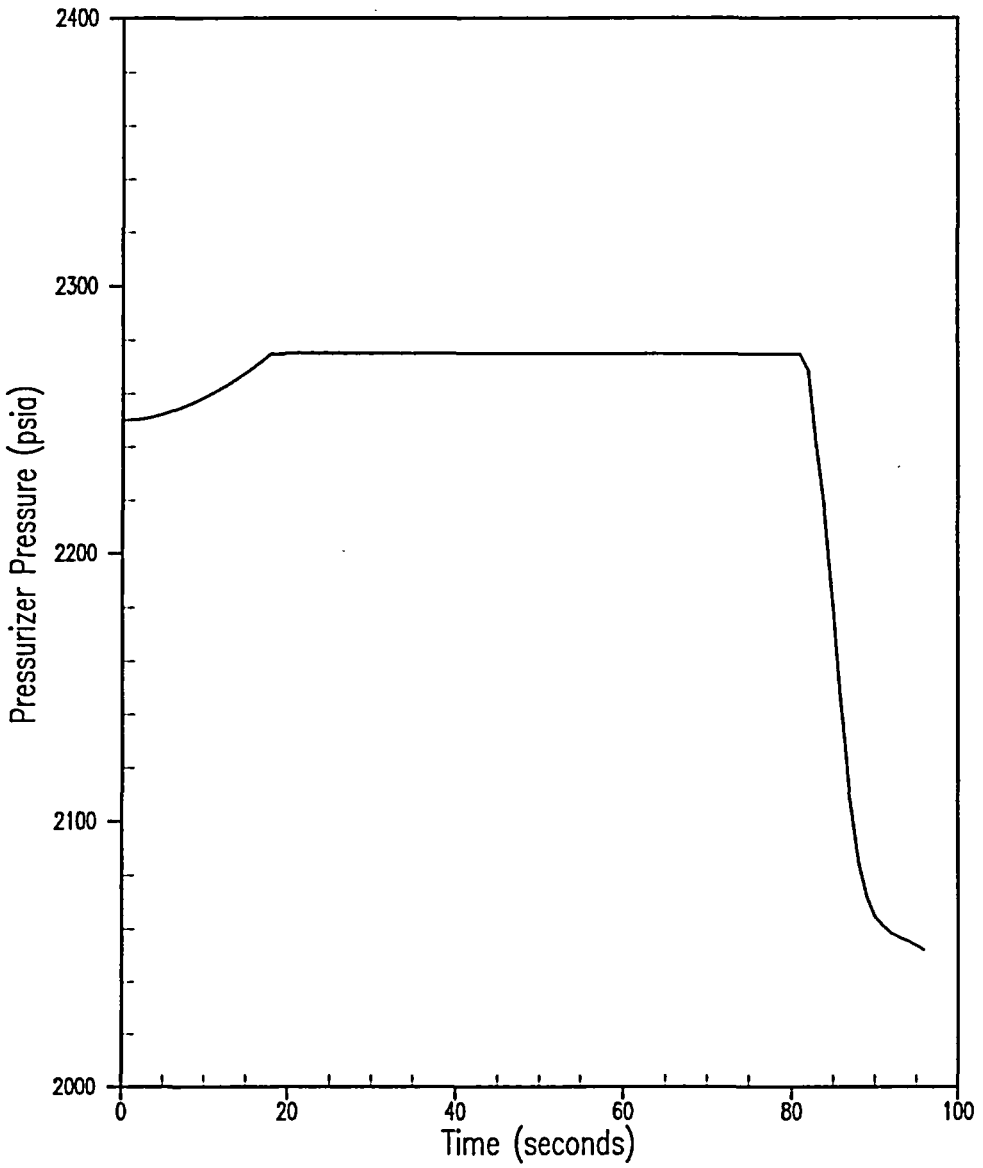


Figure 6.3.5.2-6
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (1 pcm/sec - 100% Power) OTΔT Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

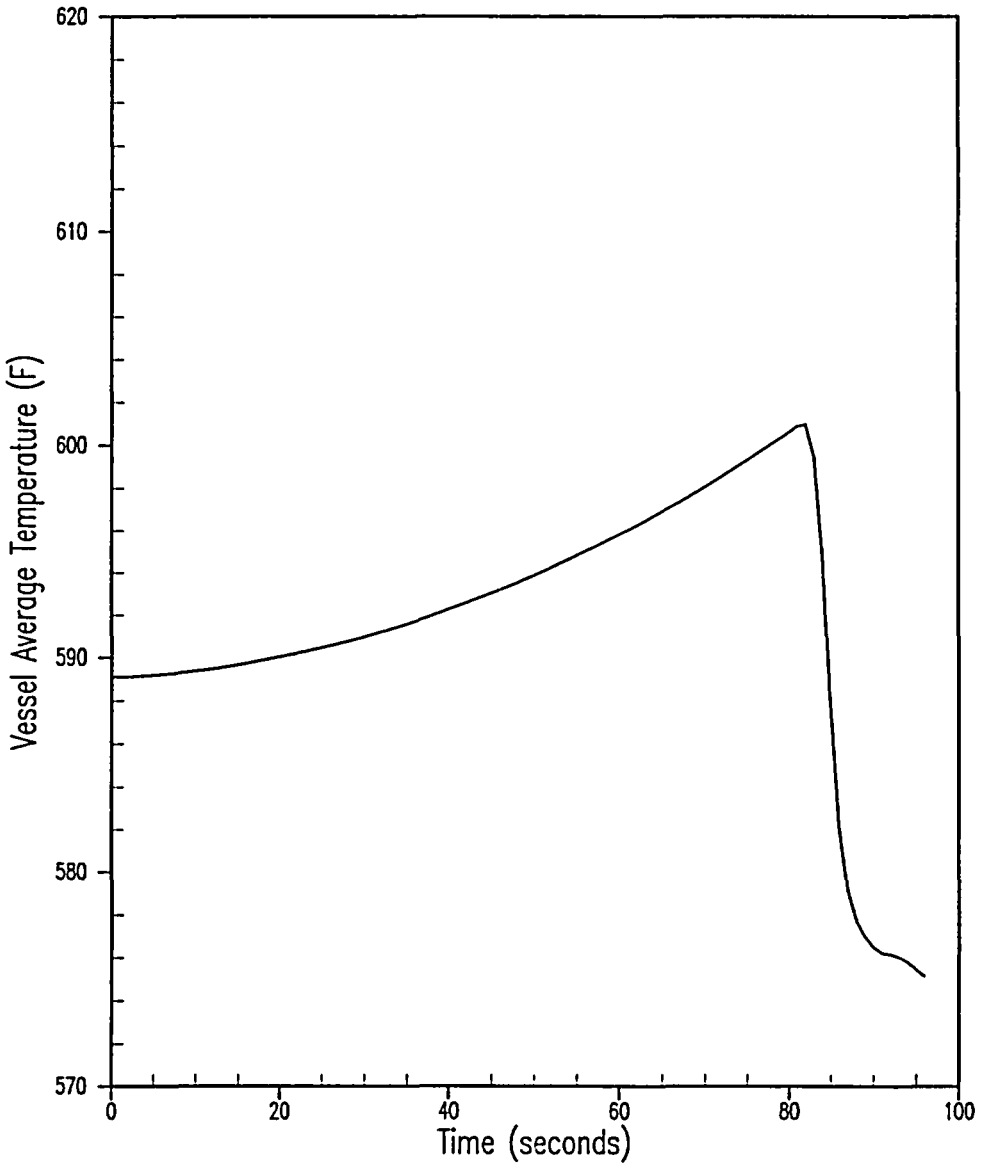


Figure 6.3.5.2-7
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (1 pcm/sec - 100% Power) OTΔT Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

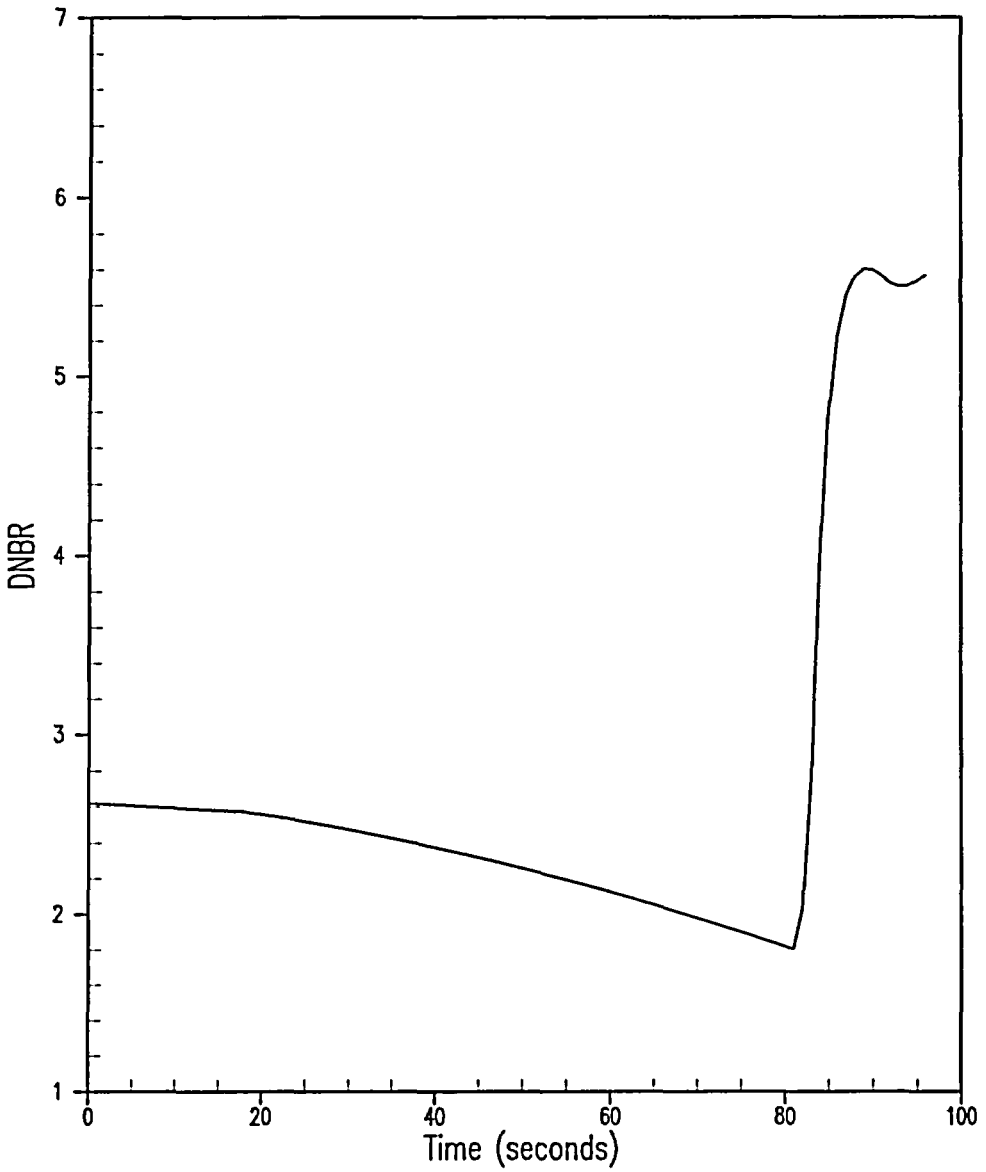


Figure 6.3.5.2-8
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power (1 pcm/sec - 100% Power) OTΔT Trip, Maximum Nominal Reactor Coolant System Vessel T_{avg}, Minimum Feedback

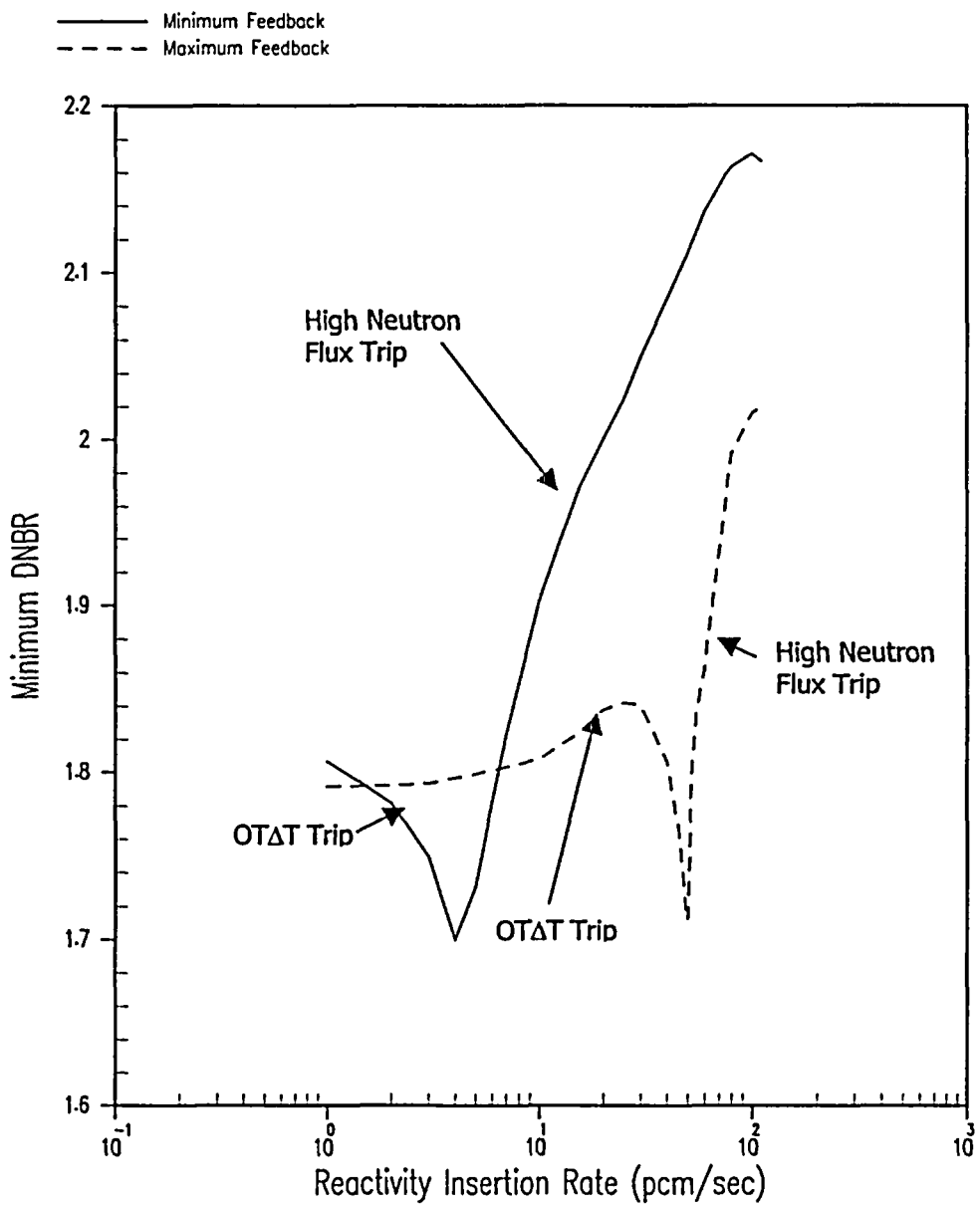


Figure 6.3.5.2-9
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power, 100% Power

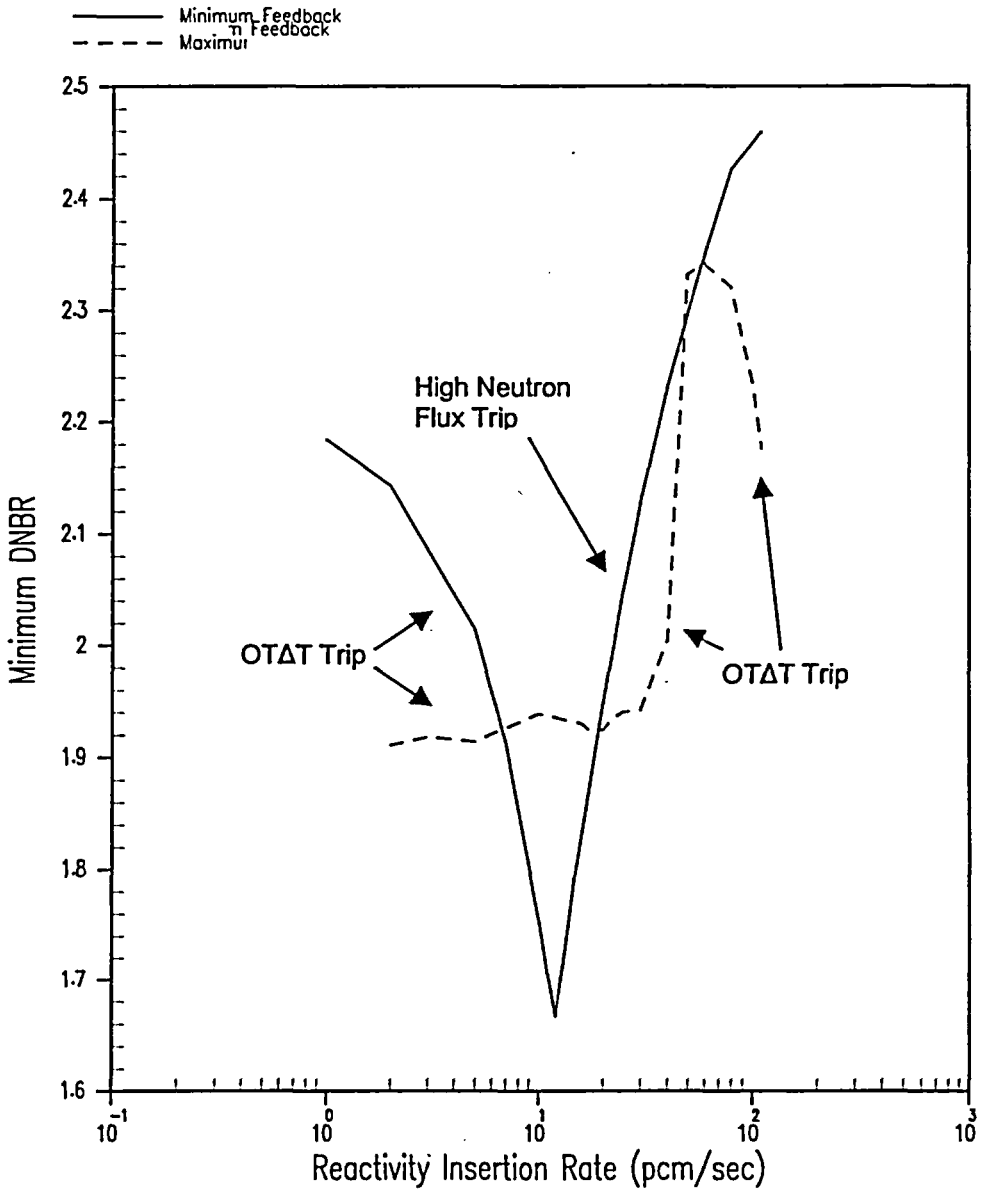


Figure 6.3.5.2-10
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power, 60% Power

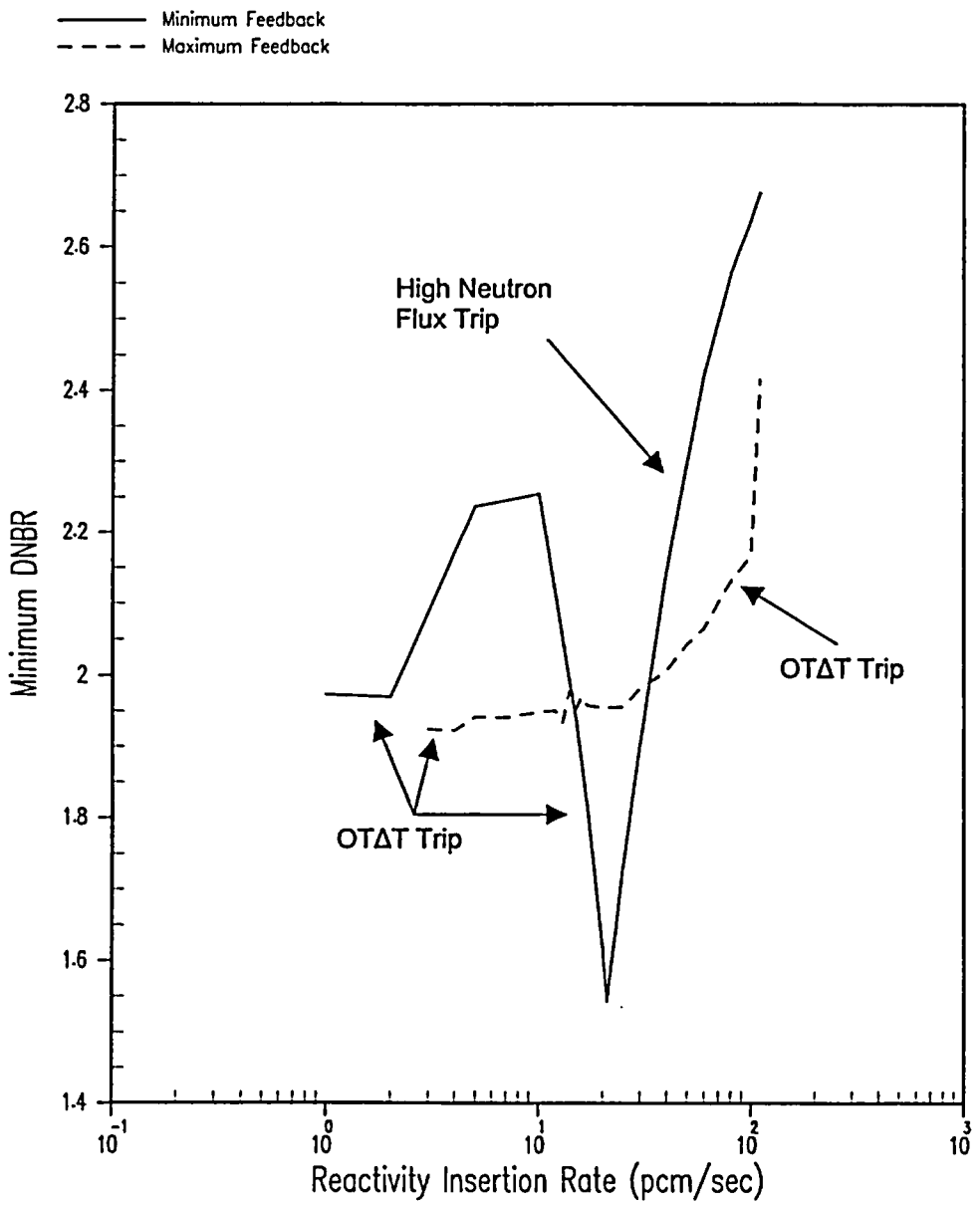


Figure 6.3.5.2-11
Uncontrolled Rod Control Cluster Assembly Bank Withdrawal at Power, 10% Power

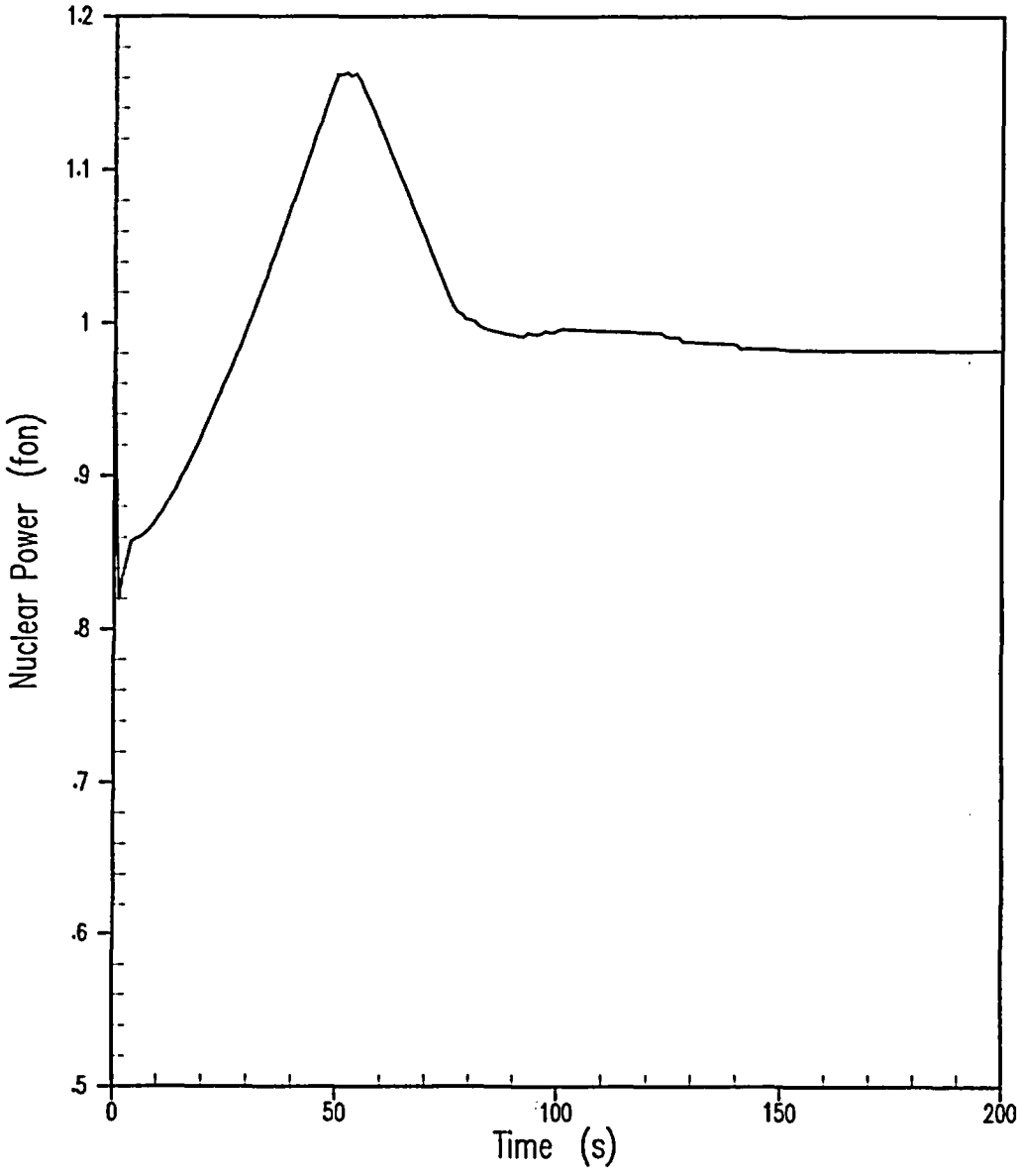


Figure 6.3.5.3-1
Representative Transient Response to Dropped Rod Control Cluster Assembly
Nuclear Power versus Time

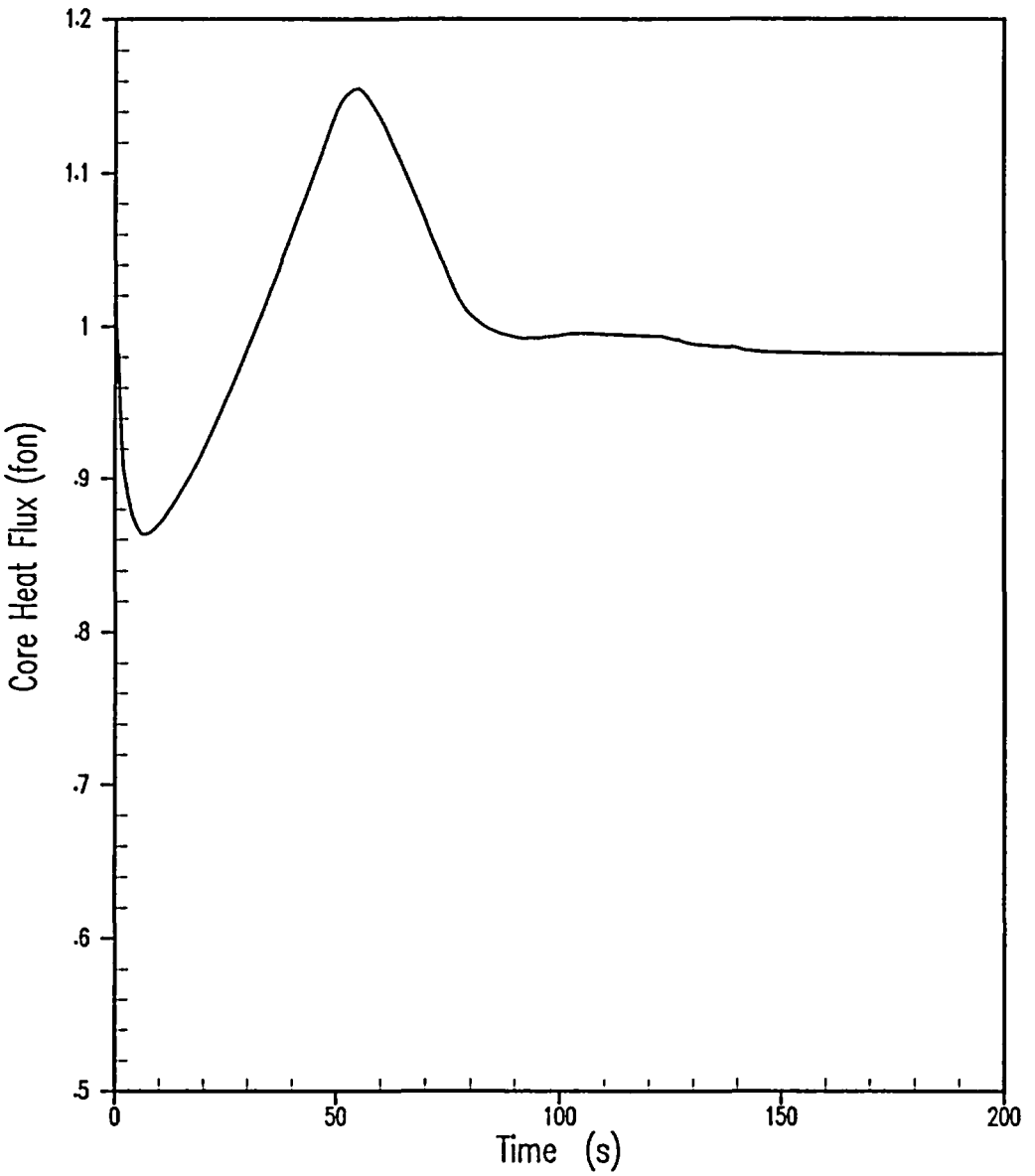


Figure 6.3.5.3-2
Representative Transient Response to Dropped Rod Control Cluster Assembly
Core Heat Flux versus Time

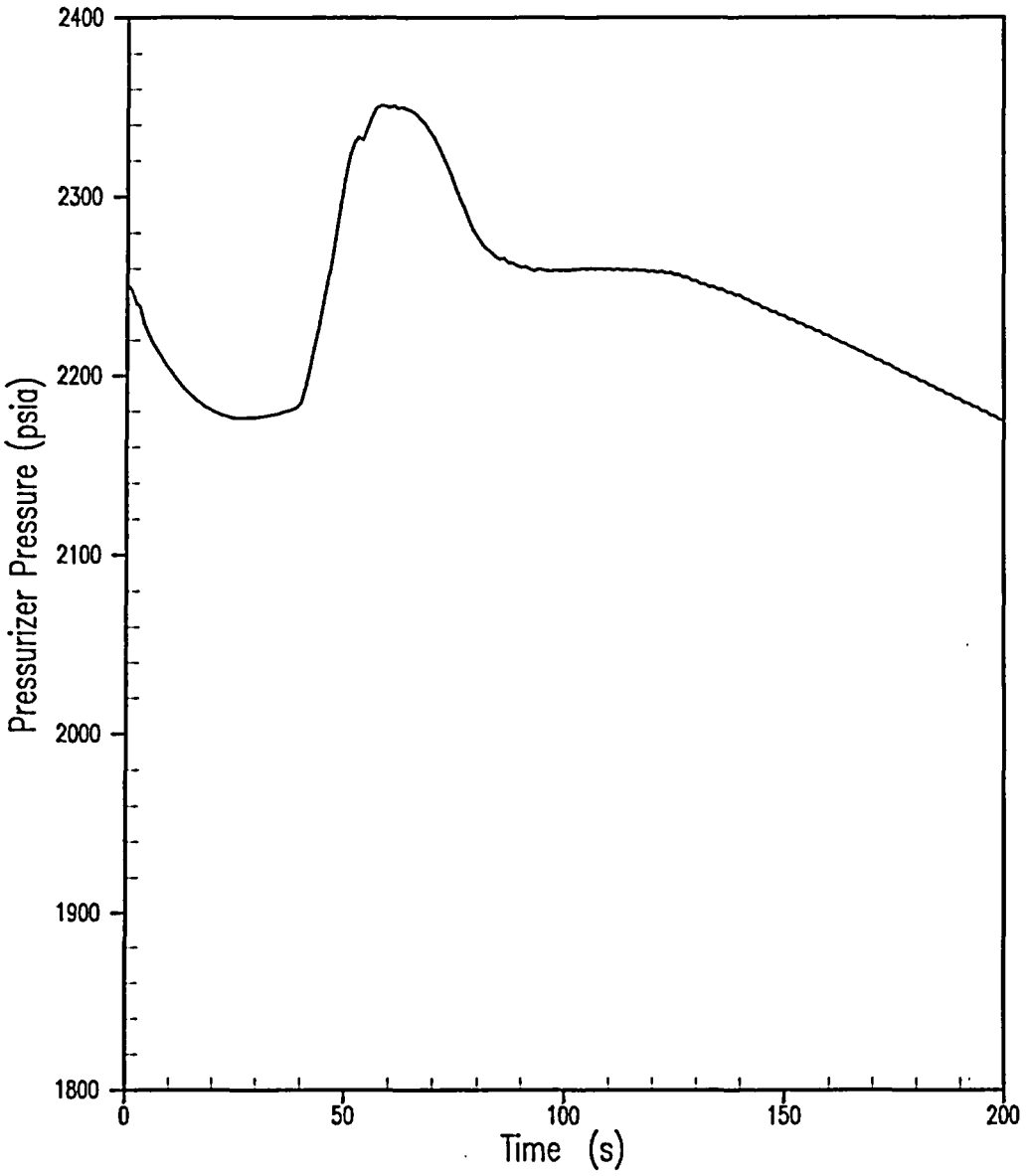


Figure 6.3.5.3-3
Representative Transient Response to Dropped Rod Control Cluster Assembly
Pressurizer Pressure versus Time

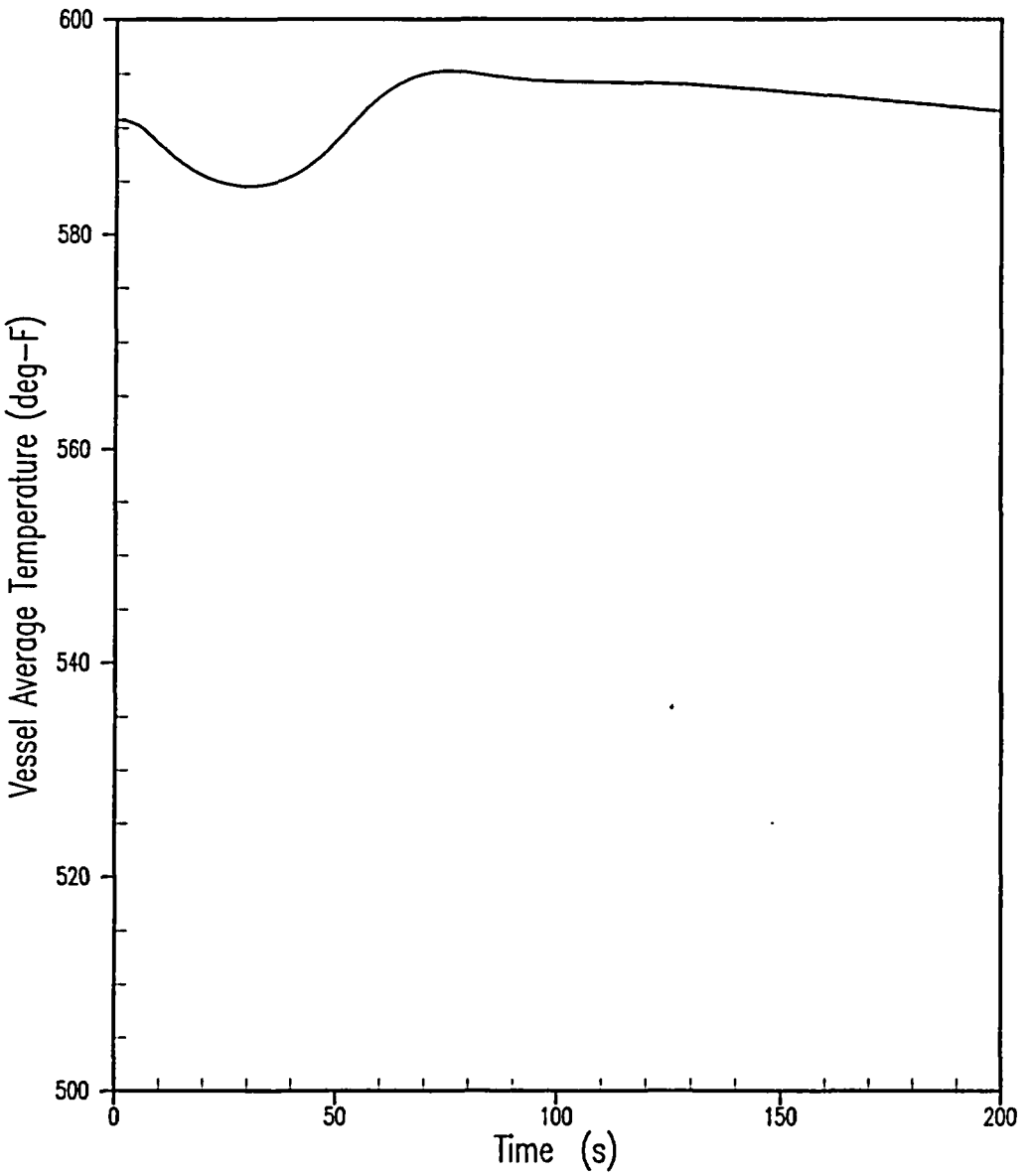


Figure 6.3.5.3-4
Representative Transient Response to Dropped Rod Control Cluster Assembly
Vessel Average Temperature versus Time

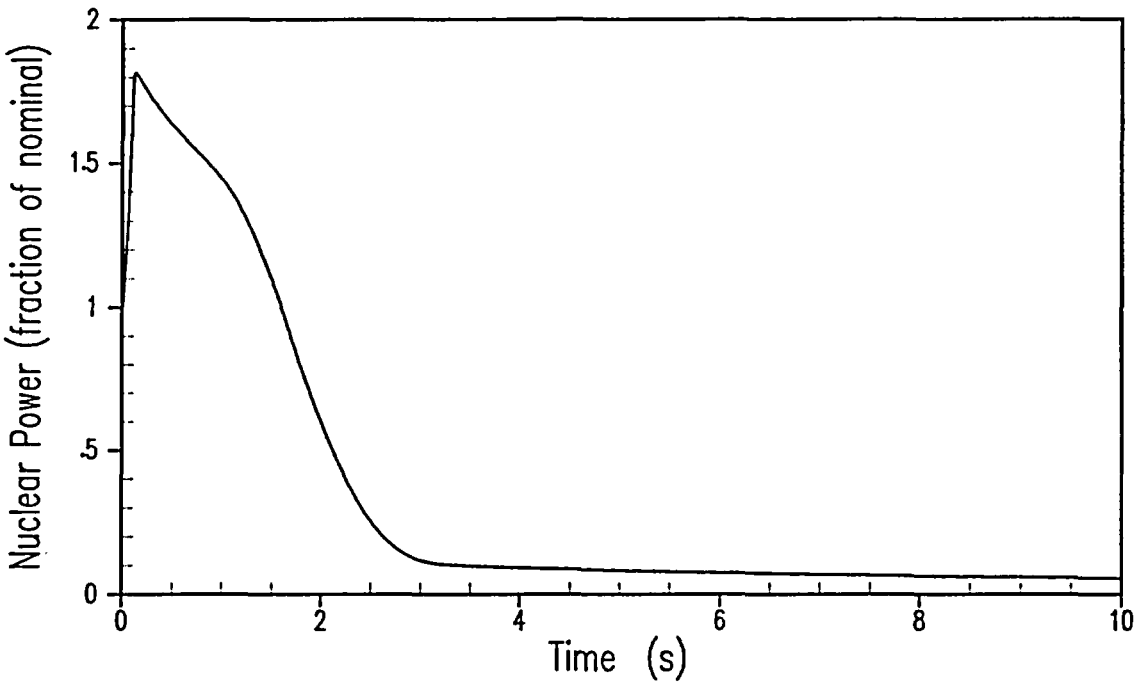


Figure 6.3.5.7-1
Rod Control Cluster Assembly Ejection Accident from Full Power Beginning of Cycle
Reactor Power versus Time

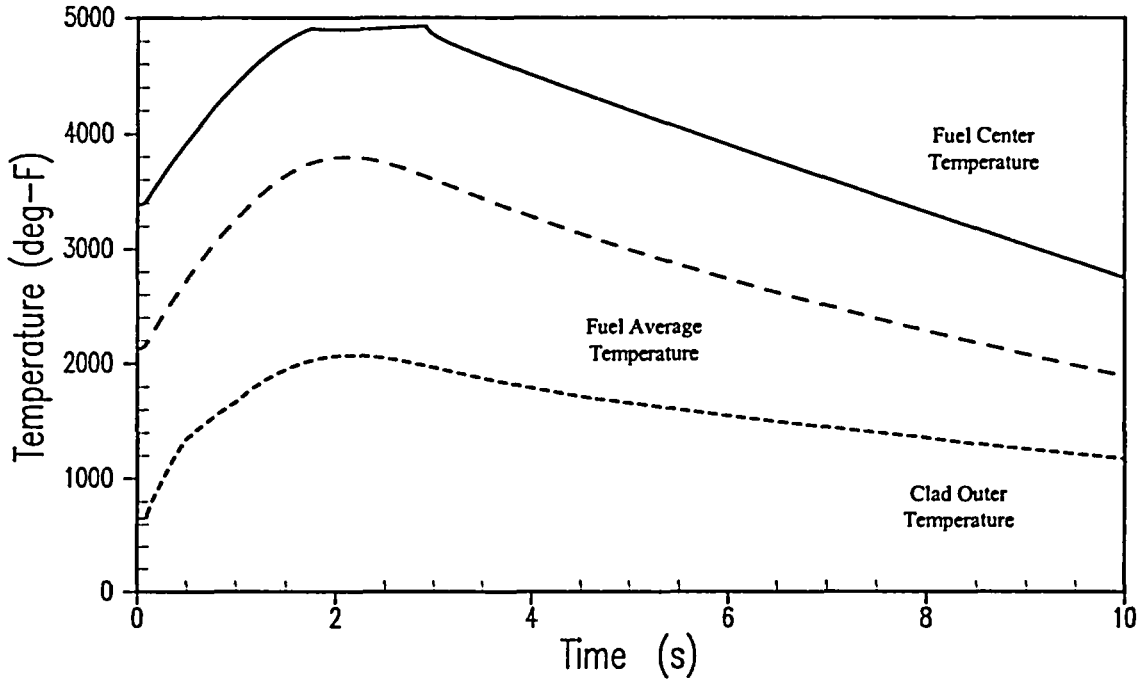


Figure 6.3.5.7-2
Rod Control Cluster Assembly Ejection Accident from Full Power Beginning of Cycle Fuel and Cladding Temperatures versus Time

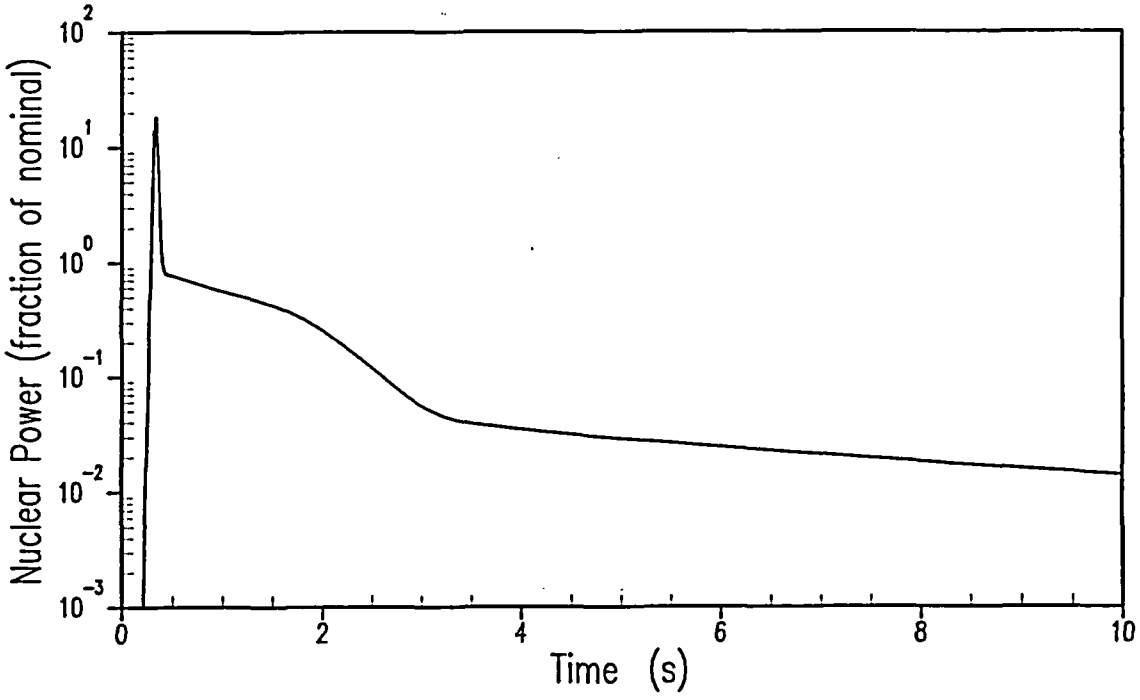


Figure 6.3.5.7-3
Rod Control Cluster Assembly Ejection Accident from Zero Power Beginning of Cycle Reactor Power versus Time

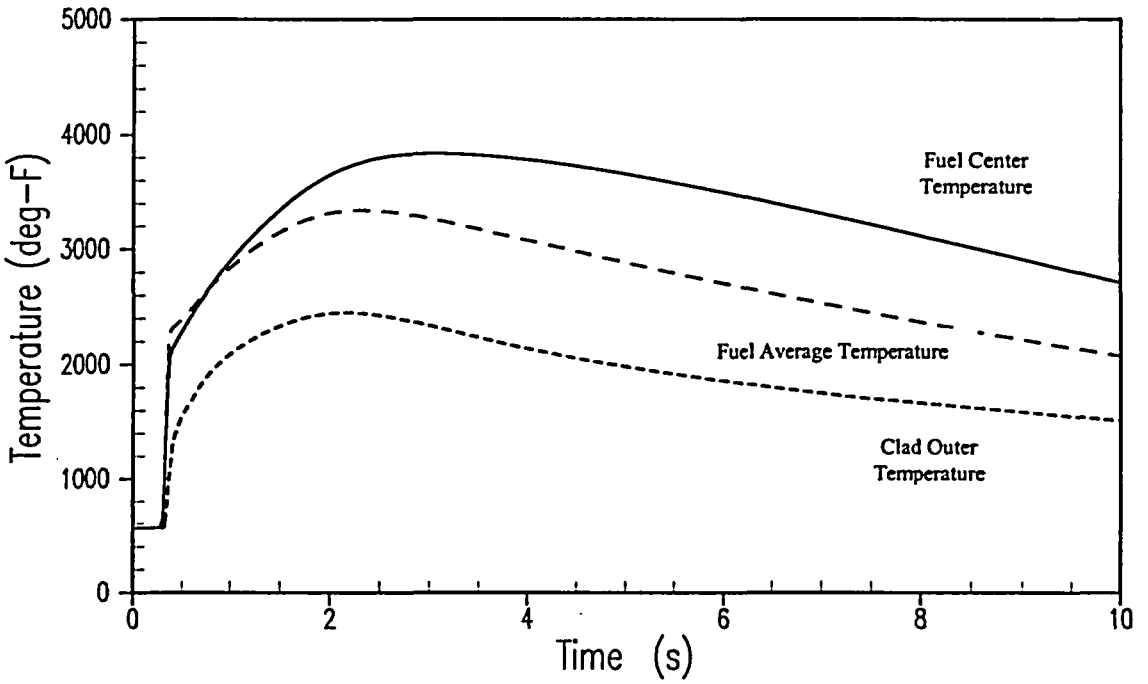


Figure 6.3.5.7-4
Rod Control Cluster Assembly Ejection Accident from Zero Power Beginning of Cycle Fuel and Cladding Temperatures versus Time

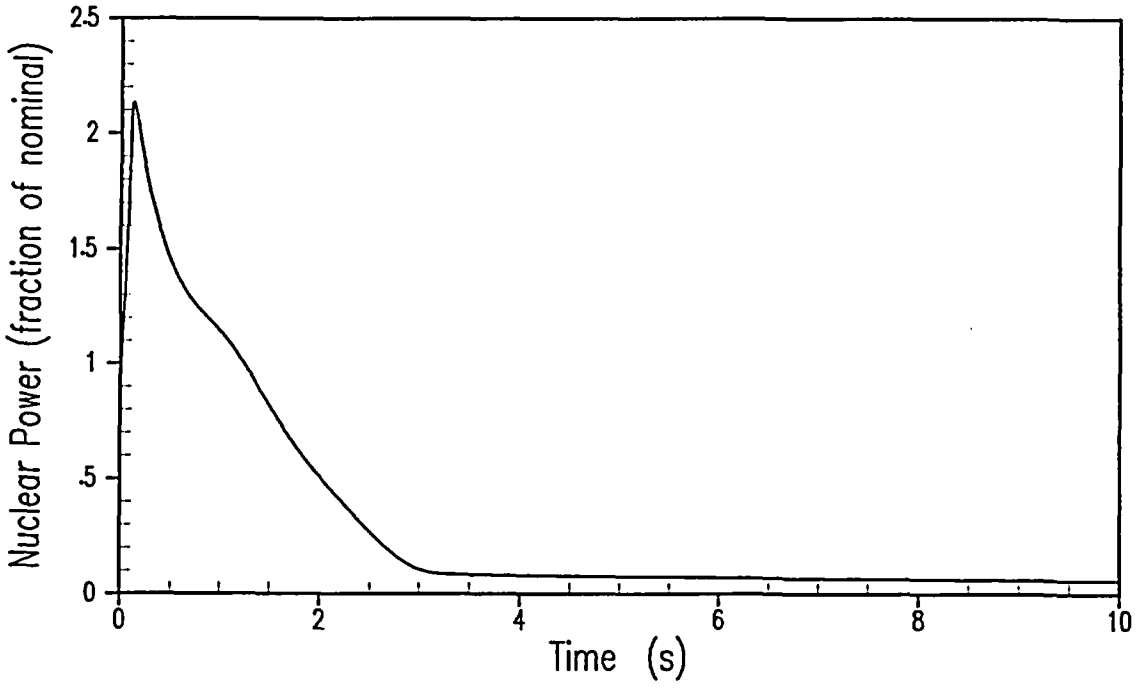


Figure 6.3.5.7-5
Rod Control Cluster Assembly Ejection Accident from Full Power End of Cycle
Reactor Power versus Time

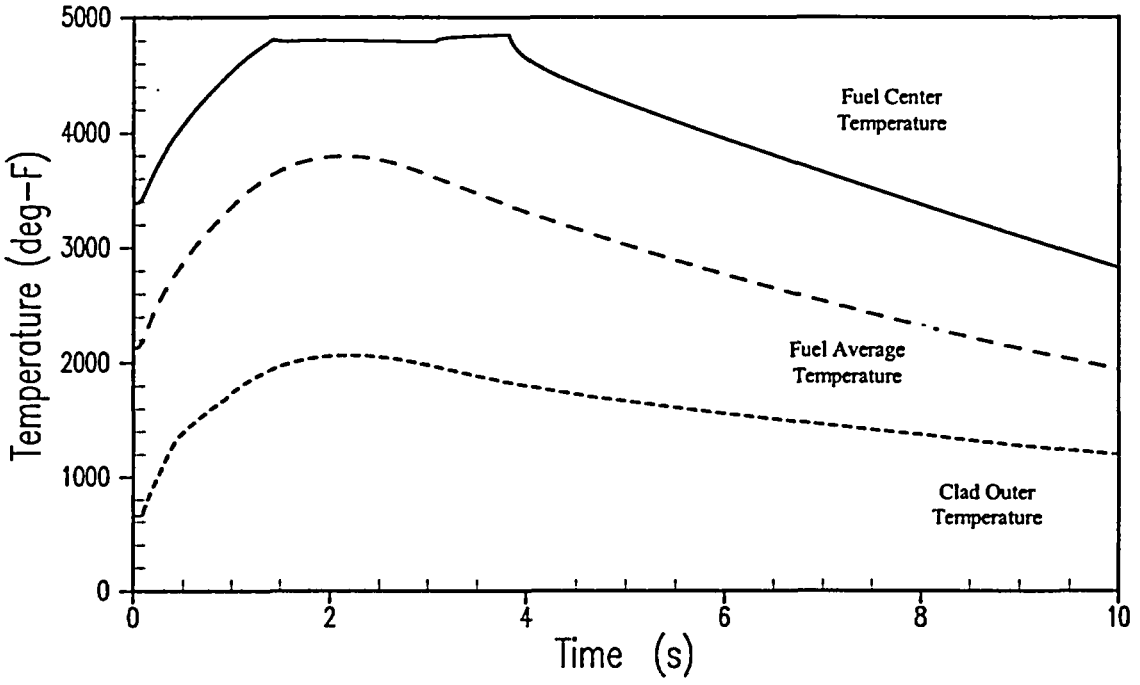


Figure 6.3.5.7-6
Rod Control Cluster Assembly Ejection Accident from Full Power End of Cycle Fuel and Cladding Temperatures versus Time

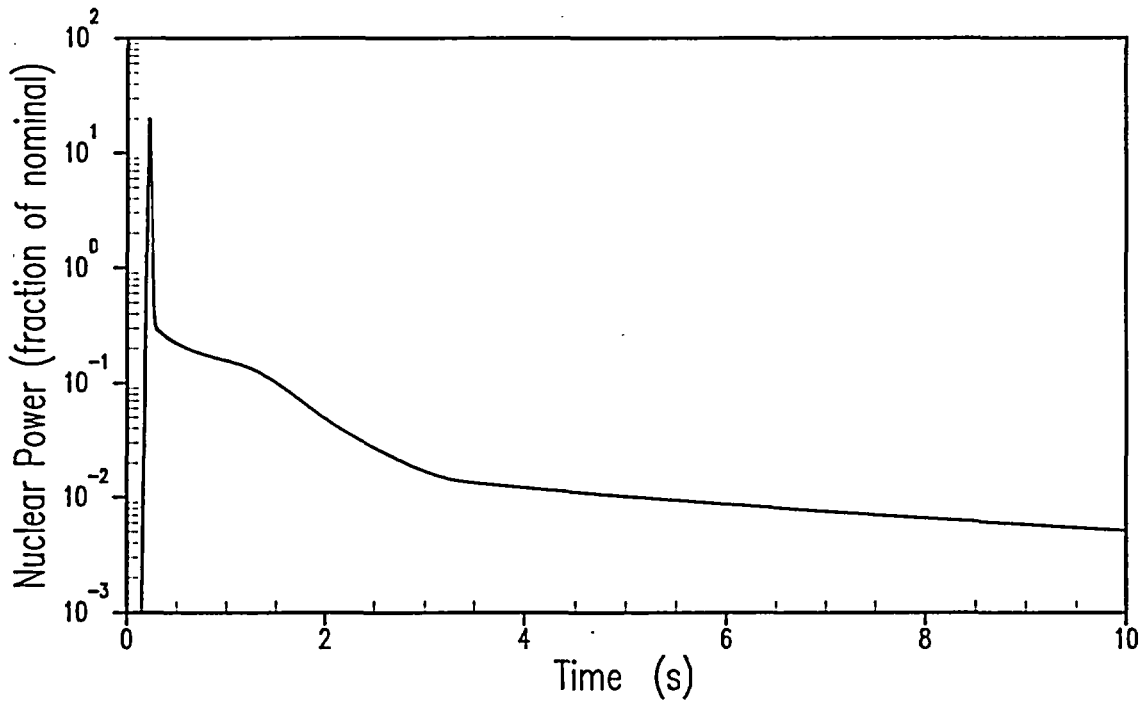


Figure 6.3.5.7-7
Rod Control Cluster Assembly Ejection Accident from Zero Power End of Cycle Reactor Power versus Time

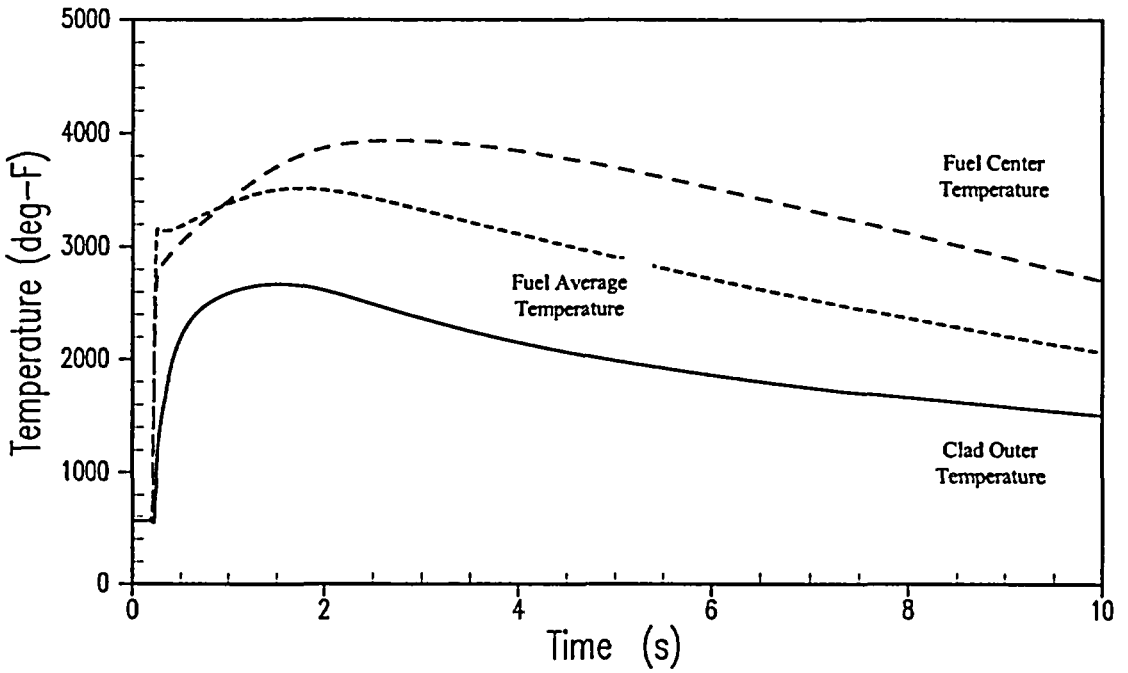


Figure 6.3.5.7-8
RCCA Ejection Accident from Zero Power End of Cycle
Fuel and Cladding Temperatures versus Time

6.3.6 INCREASE IN REACTOR COOLANT INVENTORY

6.3.6.1 INADVERTENT OPERATION OF EMERGENCY CORE COOLING SYSTEM DURING POWER OPERATION (SEABROOK STATION UFSAR SECTION 15.5.1)

6.3.6.1.1 ACCIDENT DESCRIPTION

An inadvertent or spurious actuation of the Emergency Core Cooling System at power event results in an increase in the Reactor Coolant System inventory leading to the potential filling of the pressurizer. The Inadvertent Emergency Core Cooling System Actuation at Power event could be caused by operator error or a false electrical actuating signal. Spurious actuation in plants designed with the "new" steamline break protection system may be caused by any of the following signals:

- High containment pressure
- Low pressurizer pressure
- Low steamline pressure
- Manual actuation

Following actuation of one or more of the above signals, the Safety Injection System is actuated which results in borated water being pumped from the refueling water storage tank. The centrifugal charging pumps then inject borated water into the cold leg of each Reactor Coolant System loop. The safety injection pumps also start automatically but provide no flow when the reactor coolant system is at normal pressure.

Normally, a safety injection signal results in an immediate automatic reactor trip, which in turn generates a turbine trip. However, it cannot be assumed that a single fault that actuated the Emergency Core Cooling System will also produce a reactor trip. Even without an immediate reactor trip, the reactor will experience a negative reactivity excursion as a result of the injected borated water. This negative reactivity excursion results in a decrease in reactor power.

In manual rod control, the power mismatch causes a drop in T_{avg} and a shrinkage of the reactor coolant. Prior to a reactor trip, this results in a decrease in pressurizer pressure and water level and the turbine load will decrease due to the effect of reduced steam pressure on load. The decrease in Reactor Coolant System pressure results in an increase in safety injection flow associated with the Emergency Core Cooling System pump performance characteristics.

In automatic rod control, the above effects may be compensated for by rod control cluster assembly withdrawal as the control system responds to maintain programmed T_{avg}. Once the rods have been fully withdrawn, the event continues as described for operation in manual rod control. The transient is eventually terminated by the reactor protection system low pressurizer pressure trip or by manual trip.

This event is trivial with respect to departure from nucleate boiling since the conditions resulting from injecting borated water into the Reactor Coolant System are beneficial with respect to departure from nucleate boiling. Depending on the control systems in operation, core power and Reactor Coolant System temperatures either remain near the initial nominal conditions or decrease during this event. The Reactor Coolant System flow remains constant throughout the event. A decrease in Reactor Coolant System pressure is the only condition that may occur which would adversely affect departure from nucleate boiling. However, for the decrease in Reactor Coolant System pressure that may occur, the effects are more than offset by beneficial changes in power and temperature. The net effect is a departure from nucleate boiling ratio that remains near the initial departure from nucleate boiling ratio or increases throughout the event.

The major concern that results from an Inadvertent Emergency Core Cooling System Actuation at Power event is associated with pressurizer overfill. The pressurizer water volume increases for this event as a result of the safety injection flow and operator action is ultimately required to terminate safety injection. The event is analyzed to demonstrate that sufficient time is available for appropriate operator action to mitigate the consequences of this event.

6.3.6.1.2 METHOD OF ANALYSIS

The Inadvertent Emergency Core Cooling System at Power event is analyzed with a Westinghouse version of the RETRAN-02 computer code [Reference 6.3-1].

The RETRAN-02 computer code is a digital computer code, developed to simulate transient behavior in light water reactor systems. The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, two-phase natural convection heat transfer correlations, a non-equilibrium pressurizer model, etc. The code computes pertinent plant variables including temperatures, pressures and power level.

Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits departure from nucleate boiling ratio.

For maximizing the potential for pressurizer filling (and the possibility for subsequent water relief through the pressurizer safety valves), the most limiting case is the maximum reactivity feedback condition with an immediate reactor trip on Safety Injection followed by a turbine trip on reactor trip.

To ensure that water relief through the pressurizer safety valves is precluded for this event, operator actions are modeled. These operator actions include terminating the Emergency Core Cooling System 10 minutes after the beginning of the event.

6.3.6.1.3 RESULTS

LAR Figures 6.3.6.1-1 through 6.3.6.1-3 show the evolution of the key parameters during the transient. LAR Table 6.3.6.1-1 presents the sequence of events.

Reactor trip occurs at event initiation followed by a rapid initial cooldown of the Reactor Coolant System. Coolant contraction results in a short-term reduction in pressurizer pressure and water level. The combination of the Reactor Coolant System heatup, due to residual Reactor Coolant System heat generation, and Emergency Core Cooling Systems injected flow causes the pressure and level transient to rapidly turn around. Pressurizer water level then increases throughout the transient.

The pressurizer becomes water solid shortly before nine minutes into the transient. Operator action is therefore needed to preclude water flow through the pressurizer safety valves. At 10 minutes into the transient, operator actions are assumed to terminate the safety injection flow consistent with the current licensing basis. At no time is the pressurizer safety valve setpoint challenged.

6.3.6.1.4 CONCLUSIONS

Results of the analysis show that spurious safety injection presents no hazard to the integrity of the Reactor Coolant System.

The departure from nucleate boiling ratio is never less than the initial value. Thus, there will be no cladding damage and no release of fission products to the Reactor Coolant System.

Analytical results show there will be no water flow through the pressurizer safety relief valves as a consequence of inadvertent operation of Emergency Core Cooling Systems during power operation provided that a minimum of 10 minutes is available for operator action to terminate Emergency Core Cooling Systems. No credit for operation of the pressurizer power operated relief valves was assumed.

6.3.6.2 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT INCREASES REACTOR COOLANT INVENTORY (SEABROOK STATION UFSAR SECTION 15.5.2)

6.3.6.2.1 ACCIDENT DESCRIPTION

Transients due to Chemical And Volume Control System malfunctions that increase the reactor coolant inventory can be divided into three categories:

- Category 1 Chemical And Volume Control System malfunctions that result in the injection of water with a boron concentration greater than the Reactor Coolant System boron concentration.
- Category 2 Chemical And Volume Control System malfunctions that result in the injection of water with a boron concentration less than the Reactor Coolant System boron concentration.
- Category 3 Chemical And Volume Control System malfunctions that result in the injection of water with a boron concentration equal to the Reactor Coolant System boron concentration.

There are two possible criteria for evaluating these transients: core integrity and overfilling of the pressurizer. Transients of the type listed in Category 1 are bounded by the inadvertent operation of emergency core cooling system analysis presented in

Seabrook Station UFSAR Subsection 15.5.1. Transients of the type listed in Category 2 are bounded by the Chemical And Volume Control System malfunction that results in a decrease in boron concentration in the reactor coolant presented in Seabrook Station UFSAR Subsection 15.4.6.

Chemical And Volume Control System malfunctions of the type described under Category 3 will not result in a significant nuclear power or Reactor Coolant System temperature transient; this type of transient may result in filling the pressurizer. An analysis of the Chemical And Volume Control System malfunction that results in injection of water with a boron concentration equal to the Reactor Coolant System boron concentration are presented in this section.

The most limiting case would result if charging was in automatic control and the pressurizer level channel being used for charging control failed in a low direction.

This would cause maximum charging flow to be delivered to the Reactor Coolant System and letdown flow would be isolated. The worst single failure for this event would be another pressurizer level channel failing in an as is condition or a low condition.

This will defeat the reactor trip on 2 out of 3 high pressurizer level channels. To prevent filling the pressurizer, the operator must be relied upon to terminate charging. This event is classified as an American Nuclear Society Condition II incident (an incident of moderate frequency).

6.3.6.2.2 METHOD OF ANALYSIS

The Chemical And Volume Control System Malfunction Event is analyzed with a Westinghouse version of RETRAN-02 [Reference 6.3-1].

The RETRAN-02 computer code is a digital computer code, developed to simulate transient behavior in light water reactor systems. The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, two-phase natural convection heat transfer correlations, a non-equilibrium pressurizer model, etc. The code computes pertinent plant variables including temperatures, pressures and power level.

The transient is initiated by the pressurizer level channel which is used for control purpose failing low. As a worst single failure, another pressurizer level channel fails low, defeating the two out of three high pressurizer level trip. No reactor trips are used.

Both manual and automatic control have been analyzed. No major differences were observed.

6.3.6.2.3 RESULTS

LAR Figures 6.3.6.2-1 through 6.3.6.2-2 show the evolution of the key parameters during the transient. The calculated sequence of events is shown in LAR Table 6.3.6.2-1.

In all the cases analyzed, core power and Reactor Coolant System average temperature remain relatively unchanged. The pressurizer becomes water solid at

about 13 minutes into the transient, which allows time for the operator to diagnose the problem and take corrective actions.

6.3.6.2.4 CONCLUSION

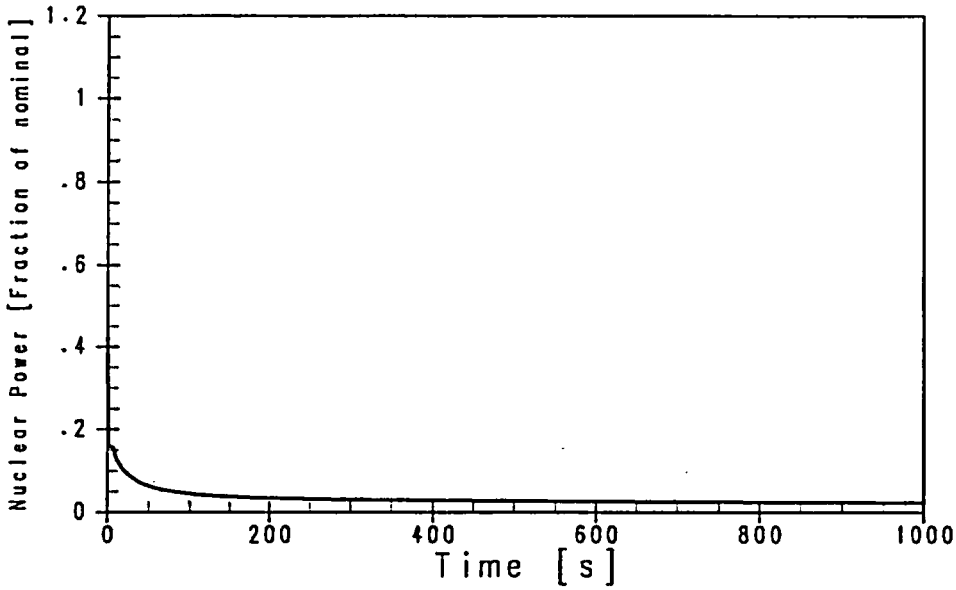
The sequence of events presented in LAR Table 6.3.6.2-1 show that the operator has sufficient time to take corrective action to preclude water passing through the pressurizer safety valves.

TABLE 6.3.6.1-1
SEQUENCE OF EVENTS
INADVERTENT EMERGENCY CORE COOLING SYSTEMS DURING POWER OPERATION

Event	Time (seconds)
Inadvertent Safety Injection actuation (manual)	0.0
Reactor trip	0.0
Turbine trip	0.01
Main steam safety valves actuation	38.38
Pressurizer level reaches 100% narrow range span	417.10
Pressurizer water volume reaches 1834.4 ft^3	535.10
Operator stops Safety Injection	600.01
Maximum pressurizer pressure (2378.18 psia)	600.01
Pressurizer pressure reaches the power operated relief valves setpoint of 2400 psia	---
First occurrence of pressurizer safety valve opening	---
End of the run	1000.0

TABLE 6.3.6.2-1
SEQUENCE OF EVENTS
CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION

Event	Time (seconds)
Two pressurizer level channels fail low; Maximum charging begins; Letdown is isolated; Low pressurizer level alarm	0.00
Pressurizer level reaches 100% narrow range span	684.10
Pressurizer water volume reaches 1834.4 ft^3	794.10
Pressurizer pressure reaches the power operated relief valves setpoint of 2400 psia	—
First occurrence of pressurizer safety valve opening	—
End of the run	1000.00



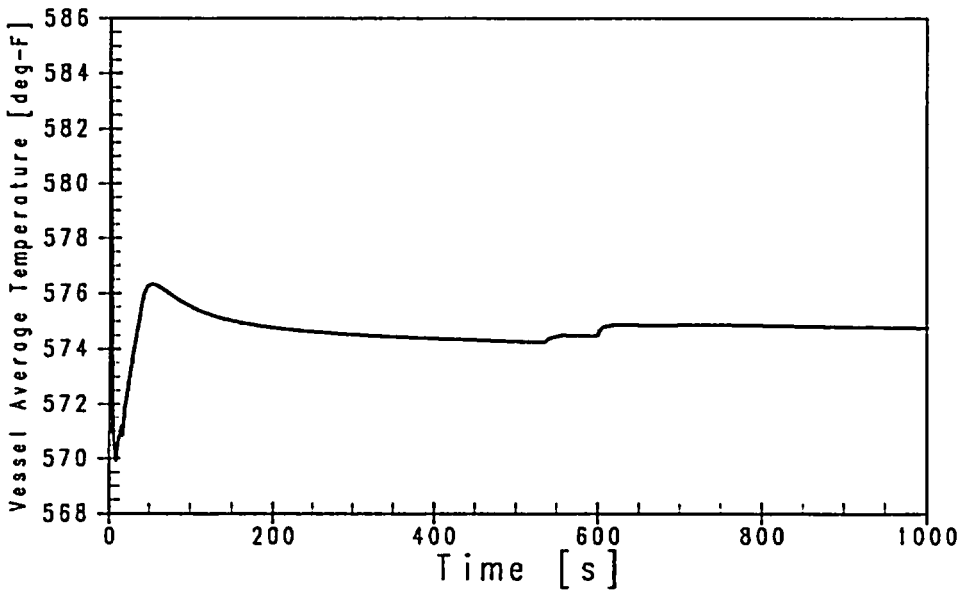
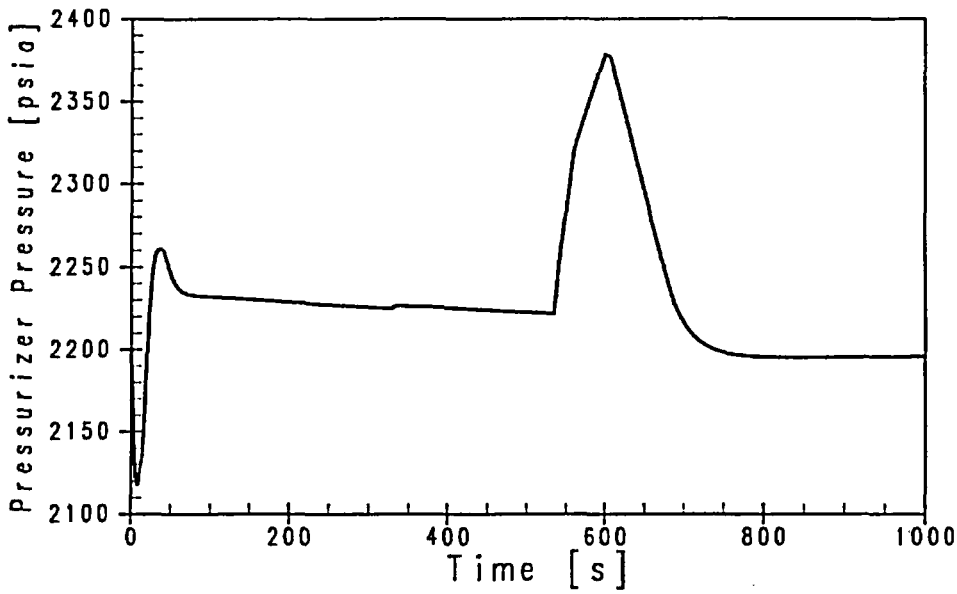


Figure 6.3.6.1-1
Inadvertent Emergency Core Cooling Systems During Power Operation
Nuclear Power and Vessel Average Temperature versus Time



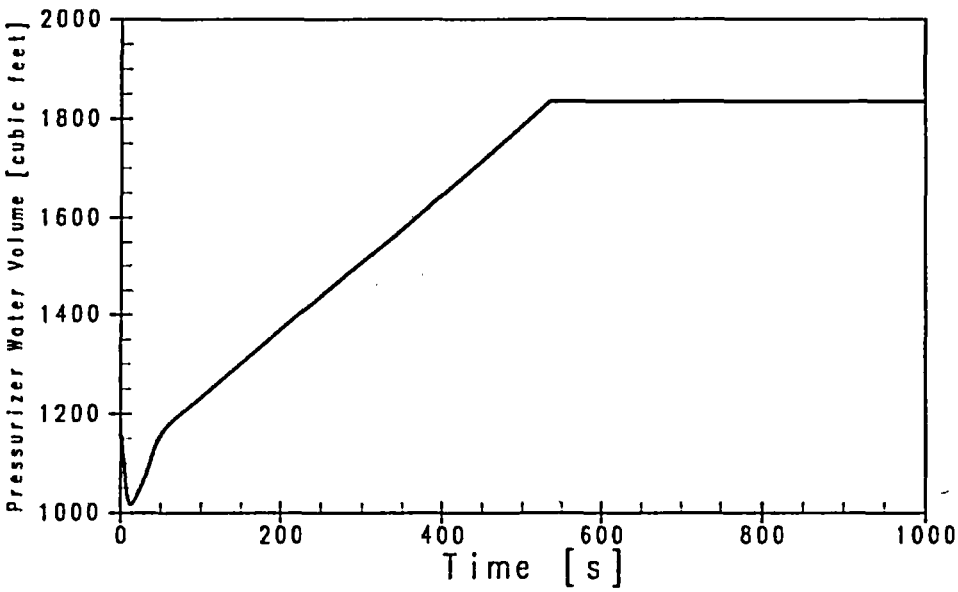


Figure 6.3.6.1-2
Inadvertent Emergency Core Cooling Systems During Power Operation
Pressurizer Pressure and Pressurizer Water Volume versus Time

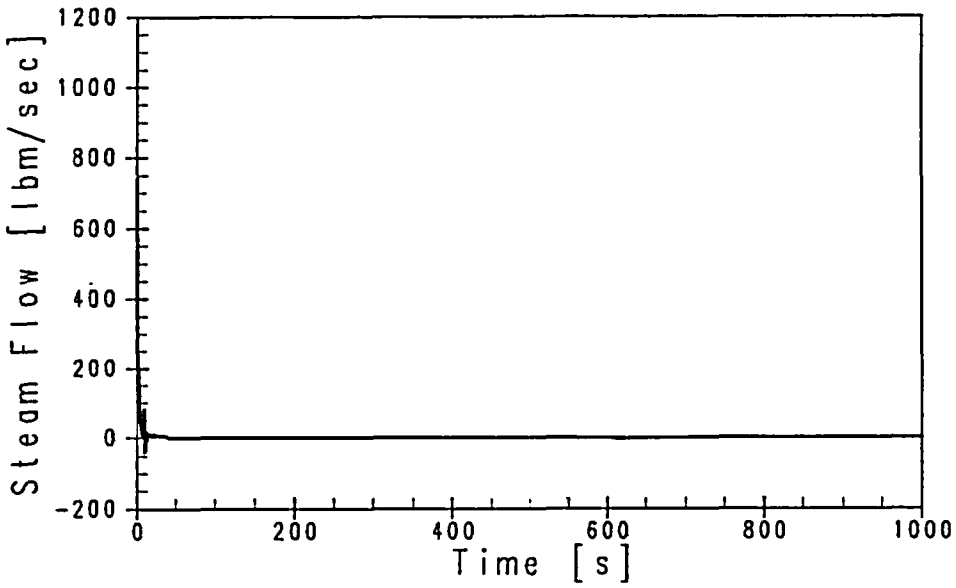
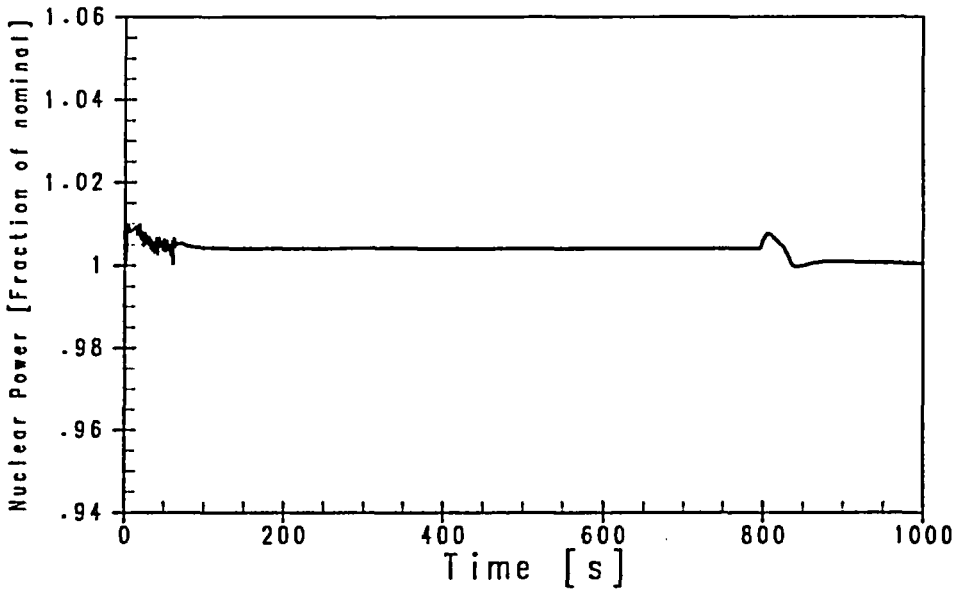


Figure 6.3.6.1-3
Inadvertent Emergency Core Cooling Systems During Power Operation
Steam Flow versus Time



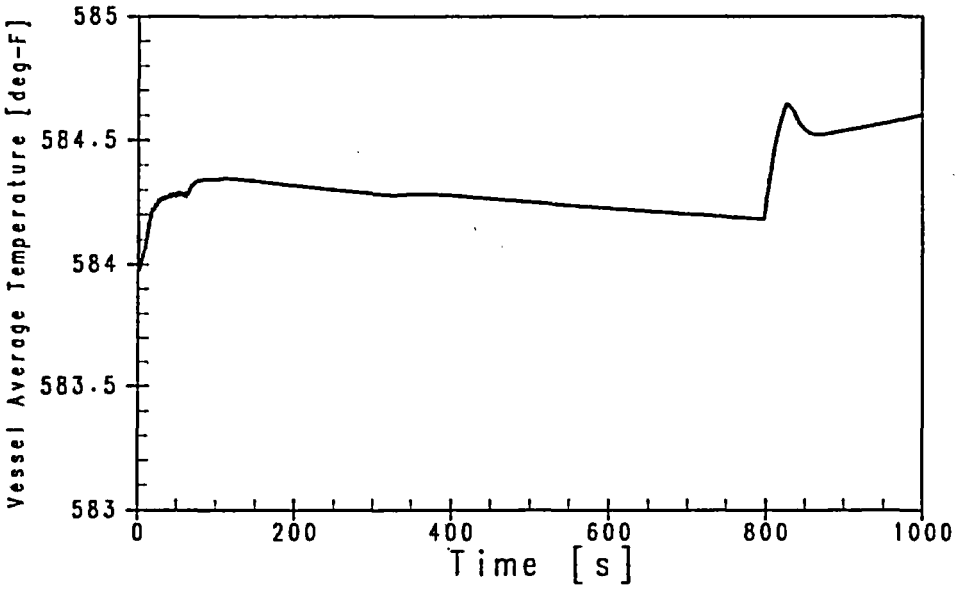
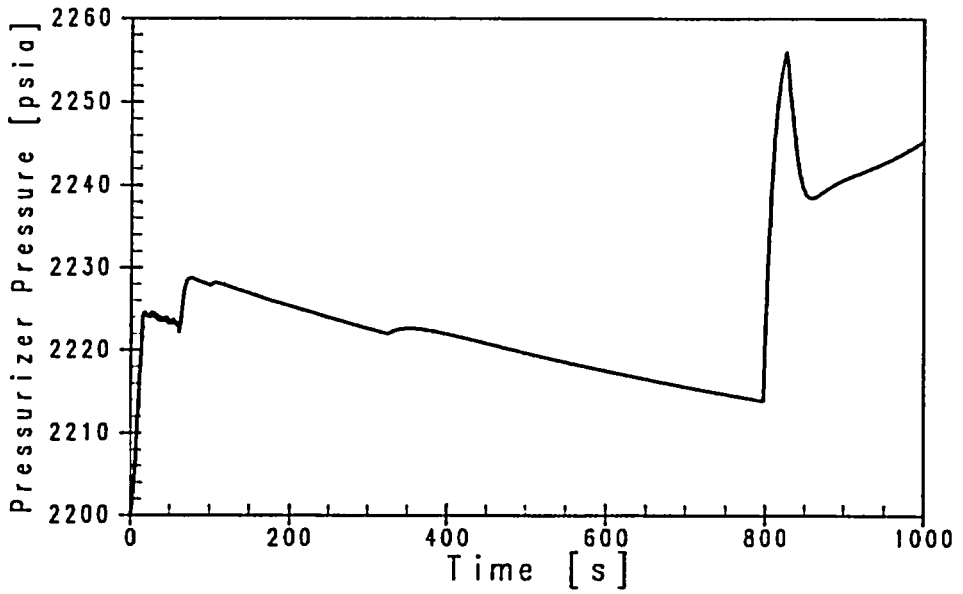


Figure 6.3.6.2-1
Chemical and Volume Control System Malfunction
Nuclear Power and Vessel Average Temperature versus Time



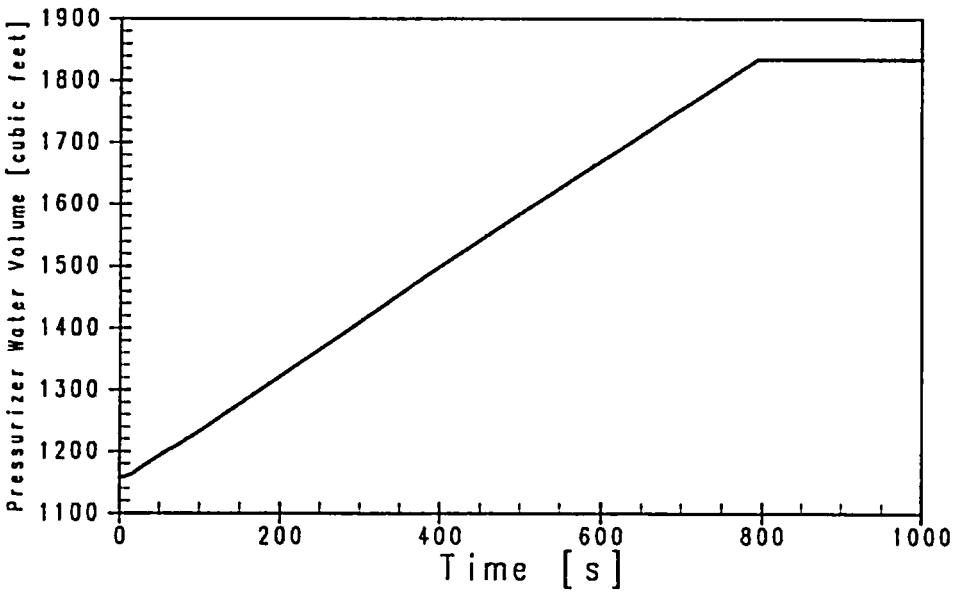


Figure 6.3.6.2-2
Chemical and Volume Control System Malfunction
Pressurizer Pressure and Pressurizer Water Volume versus Time

6.3.7 DECREASE IN REACTOR COOLANT INVENTORY

6.3.7.1 INADVERTENT OPENING OF A PRESSURIZER SAFETY OR RELIEF VALVE (SEABROOK STATION UFSAR SECTION 15.6.1)

6.3.7.1.1 ACCIDENT DESCRIPTION

An accidental depressurization of the Reactor Coolant System could occur as a result of an inadvertent opening of a pressurizer relief or safety valve. Since a safety valve is sized to relieve approximately twice the steam flow rate of a relief valve, and will therefore allow a much more rapid depressurization upon opening, the most severe core conditions resulting from an accidental depressurization of the Reactor Coolant System are associated with an inadvertent opening of a pressurizer safety valve. Initially, the event results in a rapidly decreasing Reactor Coolant System pressure until this pressure reaches a value corresponding to the hot leg saturation pressure. At this time, the pressure decrease is slowed considerably. The pressure continues to decrease throughout the transient. The effect of the pressure decrease would be to decrease power via the moderator density feedback, but the reactor control system (if in the automatic mode) functions to maintain the power essentially constant throughout the initial stage of the transient. The average coolant temperature decreases slightly. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor may be tripped by the following Reactor Protection System signals:

- Overtemperature ΔT
- Low pressurizer pressure

An inadvertent opening of a pressurizer relief valve is classified as an American Nuclear Society Condition II event, a fault of moderate frequency. The failure of a pressurizer safety valve is classified as an American Nuclear Society Condition III event. The analysis performed conservatively bounds the more limiting failure, while still applying the more restrictive Condition II acceptance criterion of ensuring the departure from nucleate boiling design basis is met.

6.3.7.1.2 METHOD OF ANALYSIS

The accidental depressurization transient is analyzed by employing the detailed digital computer code RETRAN [Reference 6.3-1]. The code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level.

This accident is analyzed with the Revised Thermal Design Procedure. In order to give conservative results in calculating the departure from nucleate boiling ratio during the transient, the following assumptions are made:

- This accident is analyzed with the Revised Thermal Design Procedure. Therefore, initial reactor power, pressure, and Reactor Coolant System temperatures are

assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit departure from nucleate boiling ratio.

- Minimum reactivity feedback is assumed to minimize the resulting departure from nucleate boiling ratio, including a moderator temperature coefficient of -0.90 pcm/°F and the least-negative Doppler coefficient.

Normal Reactor Control Systems are not required to function; however, the rod control system is assumed to be in the automatic mode in order to hold the core at full power longer and thus delay the trip. This is a worst case assumption; if the reactor were in manual control, an earlier trip could occur. The reactor protection system functions to trip the reactor on the appropriate signal. No single active failure will prevent the Reactor Protection System from functioning properly.

6.3.7.1.3 RESULTS

The system response to an inadvertent opening of a pressurizer safety valve is shown in LAR Figures 6.3.7.1-1 and 6.3.7.1-2. LAR Figure 6.3.7.1-1 illustrates the nuclear power and departure from nucleate boiling ratio transients following the depressurization. Nuclear power is maintained at the initial value until reactor trip occurs on low pressurizer pressure. The pressure decay transient and average temperature transient following the accident are given in LAR Figure 6.3.7.1-2.

Pressure drops more rapidly while core heat generation is reduced via the trip, and would then slow once saturation temperature is reached in the hot leg. The departure from nucleate boiling ratio decreases initially, but increases rapidly following the trip, as shown in LAR Figure 6.3.7.1-1.

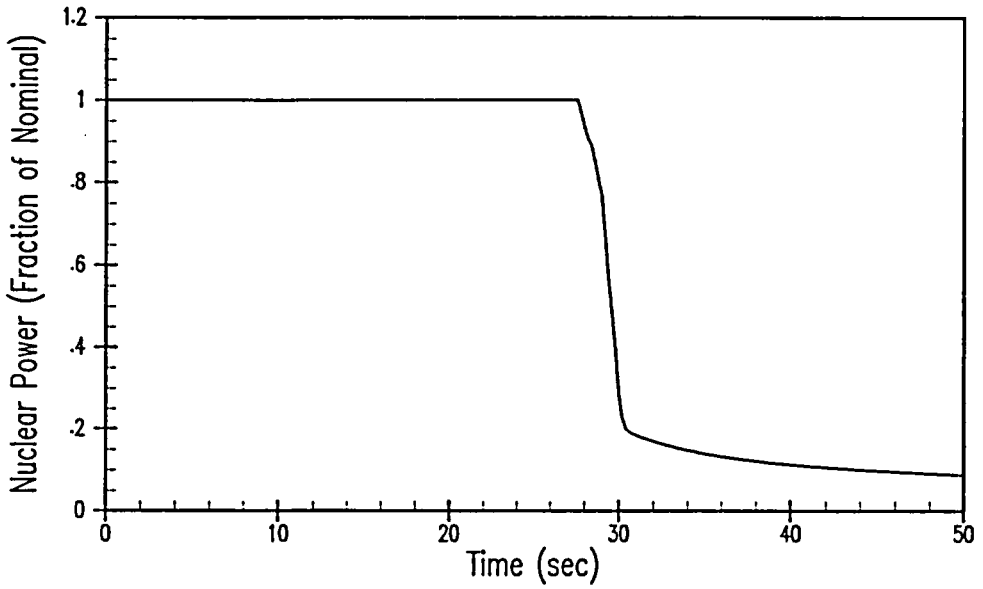
The departure from nucleate boiling ratio remains above the safety analysis limit values throughout the transient. The calculated sequence of events for the inadvertent opening of a pressurizer safety valve incident is shown on LAR Table 6.3.7.1-1.

6.3.7.1.4 CONCLUSIONS

The results of the analysis show that the low pressurizer pressure and the overtemperature ΔT Reactor Protection System signals provide adequate protection against the Reactor Coolant System depressurization event. No fuel or clad damage is predicted for this accident.

TABLE 6.3.7.1-1
TIME SEQUENCE OF EVENTS
REACTOR COOLANT SYSTEM DEPRESSURIZATION

Event	Time (seconds)
Pressurizer safety valve open fully	0.0
Low pressurizer pressure reactor trip setpoint reached	25.6
Rods begin to drop	27.6
Minimum departure from nucleate boiling ratio (1.866) occurs	27.6



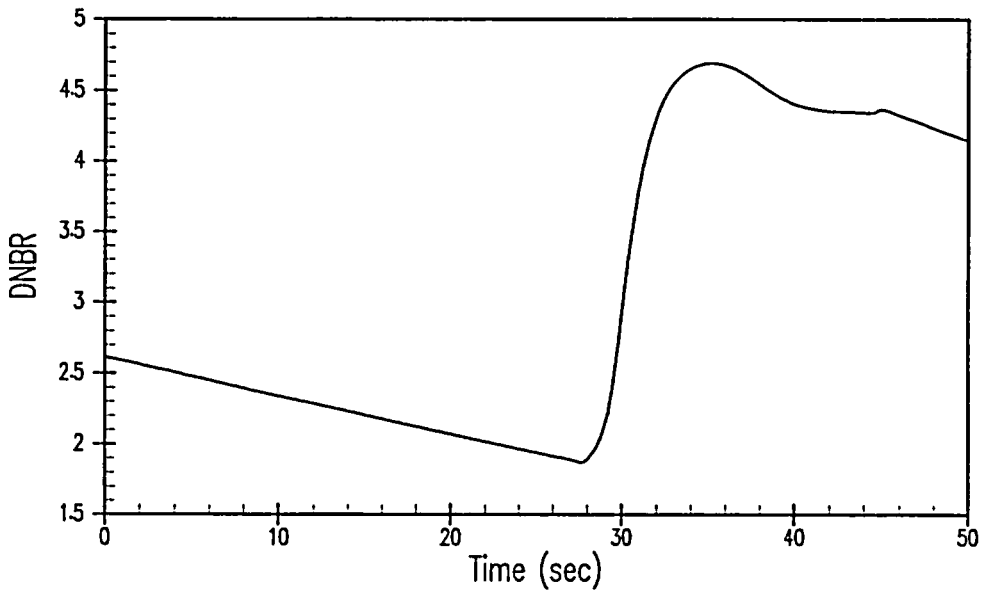
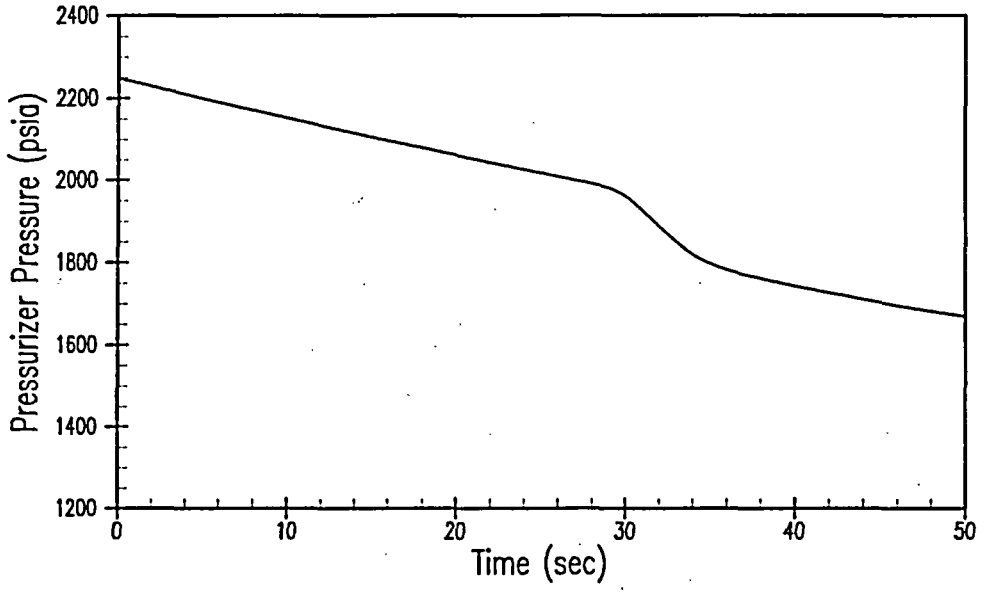


Figure 6.3.7.1-1
Inadvertent Opening of a Pressurizer Safety Valve
Nuclear Power and Departure from Nucleate Boiling Ratio Transients



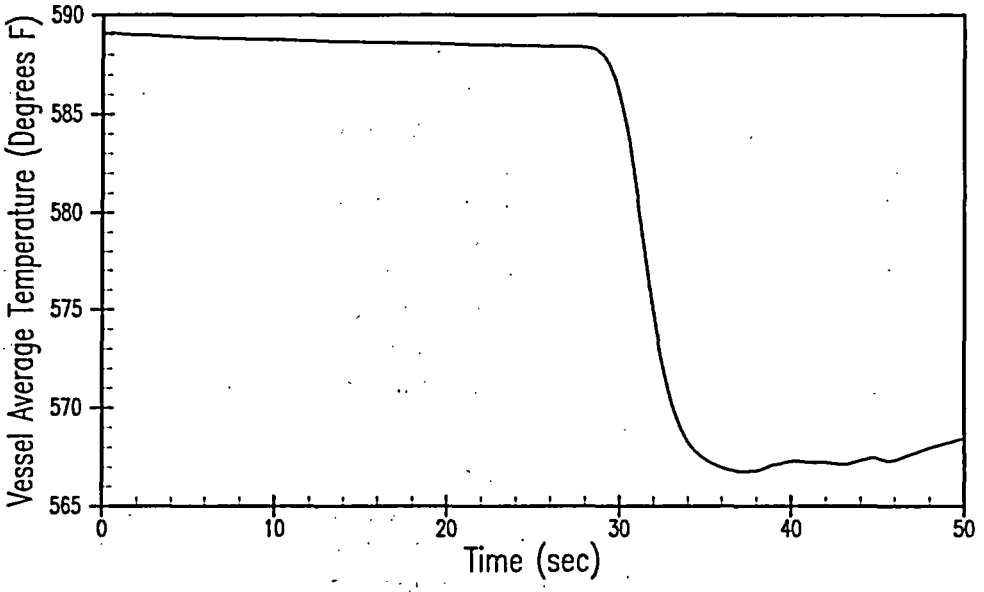


Figure 6.3.7.1-2
Inadvertent Opening of a Pressurizer Safety Valve
Pressurizer Pressure and Vessel Average Temperature Transients

6.3.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM (ATWS)

6.3.8.1 DESCRIPTION

An Anticipated Transient Without Scram (ATWS) is a postulated anticipated operational occurrence (such as loss of feedwater, loss of load, or loss of off-site power) that is accompanied by a failure of the Reactor Protection System to shutdown the reactor.

The final Anticipated Transient Without Scram rule, 10 CFR 50.62(c) [Reference 6.3-19], requires that Westinghouse designed plants such as the Seabrook Station install Nuclear Regulatory Commission approved Anticipated Transient Without Scram Mitigating System Actuation Circuitry to initiate a turbine trip and actuate emergency feedwater flow independent of the Reactor Protection System. An Anticipated Transient Without Scram mitigation system has been installed at the Seabrook Station, thus satisfying the requirements of 10 CFR 50.62(c).

6.3.8.2 METHOD OF ANALYSIS

The basis for the final Anticipated Transient Without Scram rule and the Anticipated Transient Without Scram Mitigating System Actuation Circuitry design is supported by Westinghouse analyses documented in NS-TMA-2182 [Reference 6.3-20]. These analyses were performed based on the guidelines published in NUREG-0460 (1978) [Reference 6.3-21]. Appendix A of WASH-1270 [Reference 6.3-22] states that in evaluating the reactor coolant system boundary for Anticipated Transient Without Scram events, "the calculated reactor coolant system transient pressure should be limited such that the maximum primary stress anywhere in the system boundary is less than that of the "emergency conditions" as defined in the ASME Nuclear Power Plant Components Code, Section III" (recently termed Service Limit C). Based on a review of reactor vessels for 2-, 3- and 4-loop plants, the maximum allowable pressure for the reactor vessel is 3200 psig. This value corresponds to the maximum allowable pressure for the weakest component in the reactor pressure vessel (the nozzle safe end); thus, the Reference 6.3-20 analyses were performed to demonstrate that the Reactor Coolant System pressure did not exceed 3200 psig (3215 psia). Reference 6.3-20 describes the methods used in the analyses and provides reference analyses for 2-loop, 3-loop and 4-loop plant designs with several different steam generator models available in plants at that time.

The loss of normal feedwater and loss of load Anticipated Transient Without Scram events are the two most limiting Reactor Coolant System overpressure transients reported in Reference 6.3-20. To address the SPU for the Seabrook Station, these two events were reanalyzed at the SPU conditions to ensure that the basis for the final Anticipated Transient Without Scram rule continues to be met.

The primary input to the loss of normal feedwater and loss of load Anticipated Transient Without Scram analyses performed in support of the Seabrook Station SPU are the 4-loop reference loss of normal feedwater and loss of load Anticipated Transient Without Scram models with Model F steam generators supporting Reference 6.3-20. The

nominal and initial conditions were updated to reflect an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

Seabrook Station has two emergency feedwater pumps, one motor-driven and one turbine-driven pump. The design flow capacity of each pump is 710 gpm for a total emergency feedwater flow of 1420 gpm. The emergency feedwater flow assumed in the Reference 6.3-20 analysis was a best-estimate value of 1760 gpm. In support of the SPU, three cases were run for both the loss of normal feedwater and loss of load Anticipated Transient Without Scram events, one with the Reference 6.3-20 best-estimate feedwater flow of 1760 gpm and two sensitivity cases, one with the Seabrook Station emergency feedwater design flow capacity of 1420 gpm and one with an assumed maximum emergency feedwater flow capacity of 1337 gpm.

6.3.8.2.1 RESULTS AND CONCLUSIONS

To remain consistent with the basis of the final Anticipated Transient Without Scram rule and the supporting analyses reported in Reference 6.3-20, the peak Reactor Coolant System pressure calculated for the Seabrook Station loss of load and loss of normal feedwater Anticipated Transient Without Scram events at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) corresponding to the SPU should not exceed the ASME Boiler and Vessel Code Level C service limit stress criteria of 3215 psia.

In all cases analyzed, the results obtained do not exceed the ASME Boiler and Vessel Code Level C service limit stress criteria of 3215 psia. Thus, it has been demonstrated that the analytical basis for the final Anticipated Transient Without Scram rule continues to be met for operation of the Seabrook Station at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

6.3.9 STATION BLACKOUT

6.3.9.1 INTRODUCTION

10CFR 50.63 [Reference 6.3-26], Regulatory Guide 1.155 [Reference 6.3-27] and NUMARC 87-100 [Reference 6.3-28] require that each light water cooled nuclear power plant be able to withstand and recover from a loss of all alternating current power, referred to as Station Blackout. The effects of Station Blackout are not considered as part of the design basis for the transients analyzed in Seabrook Station UFSAR Chapter 15. The capability for Seabrook Station to cope with Station Blackout is described in Seabrook Station UFSAR Section 8.4.

6.3.9.2 STATION BLACKOUT DURATION

Seabrook Station's Station Blackout coping duration is four hours. This is based on an evaluation of the offsite power design characteristics, emergency AC power system configuration and emergency diesel generator reliability in accordance with the evaluation procedure outlined in NUMARC 87-100. The offsite power design characteristics include the expected frequency of grid-related loss of offsite power, the estimated frequency of loss of offsite power from severe and extremely severe weather, and the independence of offsite power. The SPU does not impact the above offsite power design characteristics, modify the emergency AC power system configuration or affect the emergency diesel generator reliability. Therefore, the SPU has no impact on Seabrook Station's Station Blackout coping duration.

6.3.9.3 COPING ASSESSMENT

Condensate Inventory for Decay Heat Removal

Seabrook Station UFSAR Section 8.4.4.1 indicates that the current condensate storage tank inventory requirement for decay heat removal during the four hour Station Blackout coping period is 131,137 gallons. This inventory requirement will increase slightly to 137,000 gallons, resulting from increased decay heat related to the SPU. This value includes decay heat removal, removal of sensible heat and steam generator level shrinkage. This requirement is significantly below the minimum condensate storage tank usable inventory of 196,000 gallons. Therefore, the current condensate storage tank minimum usable inventory supports Station Blackout decay heat removal requirements for the SPU.

Battery Capacity

The SPU does not increase the loads required to cope with the Station Blackout, nor does it impact the load shedding requirement. Station Blackout battery sizing requirements are not impacted by SPU. Therefore, the SPU has no impact on Station Blackout battery capacity.

Compressed Air

The only air-operated valves required for decay heat removal during the four hour Station Blackout coping period are the atmospheric steam dump valves. Seabrook

Station UFSAR Section 9.3.1.1 describes the backup air supply for the atmospheric steam dump valves. The backup air supply is completely independent of AC power and is sized for atmospheric steam dump valve operation over a ten hour period. Therefore, Station Blackout compressed air requirements for Seabrook Station will be met for SPU conditions.

Effects of Loss of Ventilation

The areas containing equipment required to cope with a Station Blackout were evaluated for the effects of loss of ventilation at SPU conditions. Motor horsepower, electrical loading and fluid temperatures for systems utilized during the Station Blackout four hour coping period are not affected by the SPU. Therefore, the SPU has no impact on the effects of loss of ventilation for Station Blackout.

Containment Isolation

No valves that have been identified as containment isolation valves of concern for Station Blackout are required to be operable during a Station Blackout. Therefore, the SPU has no impact on the requirements for containment isolation during Station Blackout.

Reactor Coolant Inventory

The expected rates of reactor coolant inventory loss under Station Blackout conditions will not increase as a result of the SPU. The core will not become uncovered during the four hour Station Blackout coping period. Therefore, makeup systems will not be required during Station Blackout at SPU conditions to maintain core cooling under natural circulation conditions.

6.3.9.4 CONCLUSIONS

Seabrook Station will continue to meet the requirements of 10 CFR 50.63, Regulatory Guide 1.155 and NUMARC 87-100 for a Station Blackout event under SPU conditions.

6.4 CONTAINMENT RESPONSE

6.4.1 LOSS OF COOLANT ACCIDENT (LOCA) MASS AND ENERGY RELEASE

The uncontrolled release of pressurized high temperature reactor coolant, termed a LOCA, will result in release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures, and an increase in the global containment pressure and temperature. Therefore, there are both long and short-term issues reviewed relative to a postulated LOCA that must be considered for the SPU for the Seabrook Station.

The long-term LOCA mass and energy releases are analyzed to approximately 10^7 seconds and are utilized as input to the containment integrity analysis, which demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large break LOCA. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and to limit the temperature excursion to less than the Equipment Qualification Program acceptance limits. For this program, Westinghouse generated the mass and energy releases using the March 1979 model, described in Reference 6.4-1. The Nuclear Regulatory Commission review and approval letter is included with Reference 6.4-1. Even though this is a first time application of this methodology for Seabrook Station, it has also been utilized and approved on many plant-specific dockets. LAR Section 6.4.1.1 discusses the long-term LOCA mass and energy releases generated for this program.

The short-term LOCA-related mass and energy releases are used as input to the sub-compartment analyses, which are performed to ensure that the walls of a sub-compartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high energy line pipe rupture within that sub-compartment. As documented in the Seabrook Station UFSAR Section 6.2, based upon Leak-Before-Break, Reactor Cavity and Steam Generator over-pressurization no longer need to be considered as part of the current licensing basis. This is based upon the final rulemaking with respect to GDC-4, dated October 27, 1987. Therefore releases for these breaks are no longer required. The design basis for the sub-compartments currently includes the pressurizer compartment and the pressurizer skirt cavity. The breaks for these sub-compartments are the double-ended spray line break and the double-ended surge line break, respectively. LAR Subsection 6.4.2 discusses the short-term evaluation conducted for this program for these breaks and sub-compartments.

6.4.1.1 LONG-TERM LOCA MASS AND ENERGY RELEASES

The mass and energy release rates described in this section form the basis for the containment pressure calculations described in LAR Subsection 6.4.3. The long-term LOCA mass and energy releases for the hypothetical double-ended pump suction rupture and double-ended hot leg rupture break cases for the Seabrook Station are discussed in this section.

6.4.1.1.1 INPUT PARAMETERS AND ASSUMPTIONS

The mass and energy release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the Reactor Coolant System operating temperatures are chosen to bound the highest average coolant temperature range of the operating cases, and a temperature uncertainty allowance of (+6.0°F) is then added. Nominal parameters are used in certain instances. For example, the Reactor Coolant System pressure in this analysis is based on a nominal value of 2250 psia plus an uncertainty allowance (+50 psi). The input parameters are chosen consistent with accepted analysis methodology.

Some of the most-critical items are the Reactor Coolant System initial conditions, core decay heat, safety injection flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are next discussed. LAR Tables 6.4.1.1-1 through 6.4.1.1-3 present key data assumed in the analysis.

The maximum analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) includes any calorimetric error. As previously noted, the use of Reactor Coolant System operating temperatures to bound the highest average coolant temperature range were used as bounding analysis conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures, which are at the maximum levels attained in steady state operation. Additionally, an allowance to account for instrument error and deadband is reflected in the initial Reactor Coolant System temperatures. As previously discussed, the initial Reactor Coolant System pressure in this analysis is based on a nominal value of 2250 psia plus an allowance which accounts for the measurement uncertainty on pressurizer pressure. The selection of 2300 psia as the limiting pressure is considered to affect the blowdown phase results only, since this represents the initial pressure of the Reactor Coolant System. The Reactor Coolant System rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the Reactor Coolant System blows down is initially more severe at the higher Reactor Coolant System pressure. Additionally the Reactor Coolant System has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher Reactor Coolant System mass available for releases. Thus, 2250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term mass and energy release calculations.

The selection of the fuel design features for the long-term mass and energy release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (i.e., to maximize the core stored energy). The following fuel features are considered, 1) rod geometry, 2) rod power, and 3) limiting time in life (e.g., burnup). To conservatively address the thermal fuel model, considering uncertainties, margin, and fuel densification, a 15% uncertainty is included in the core stored energy value. Thus, the analysis very conservatively accounts for the stored energy in the core.

A margin in Reactor Coolant System volume of 3% is assumed. This is composed of 1.6% allowance for thermal expansion and 1.4% for uncertainty.

A uniform steam generator tube plugging level of 0% is modeled. This assumption maximizes the reactor coolant volume and fluid release by virtue of consideration of the Reactor Coolant System fluid in the steam generator tubes. During the post-blowdown period the steam generators are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0% tube plugging assumption maximizes heat transfer area and therefore the transfer of secondary heat across the steam generator tubes. Additionally, this assumption reduces the reactor coolant loop resistance, which reduces the pressure differential upstream of the break for the pump suction breaks and increases break flow. Thus, the analysis very conservatively accounts for the level of steam generator tube plugging.

Regarding safety injection flow, the mass and energy release calculation considered configurations and assumed failures to conservatively bound respective alignments. The cases include

1. Minimum Safeguards Case - (1 charging/safety injection pump, 1 high head safety injection pump, and 1 low head safety injection pump)
2. Maximum Safeguards Case - (2 charging/safety injection pumps, 2 high head safety injection pumps, and 2 low head safety injection pumps).

The following assumptions were employed to ensure that the mass and energy releases are conservatively calculated, thereby maximizing energy release to containment.

1. Maximum expected operating temperature of the reactor coolant system (maximum analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level)
2. Allowance for Reactor Coolant System temperature uncertainty (+6.0°F)
3. Margin in Reactor Coolant System volume of 3% (which is composed of 1.6% allowance for thermal expansion, and 1.4% for uncertainty)
4. Core analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) which includes any calorimetric error
5. Conservative heat transfer coefficient (i.e., steam generator primary/secondary heat transfer and reactor coolant system metal heat transfer)
6. Allowance in core stored energy for effect of fuel densification
7. A margin in core stored energy (+15 percent to account for manufacturing tolerances)
8. An allowance for Reactor Coolant System initial pressure uncertainty (+50 psi)
9. A maximum containment backpressure equal to design pressure (52 psig)
10. Minimum Reactor Coolant System loop flow (93,600 gpm/loop)

11. Steam generator tube plugging leveling (0% uniform)
    - Maximizes reactor coolant volume and fluid release
    - Maximizes heat transfer area across the steam generator tubes
    - Reduces coolant loop resistance, which reduces the delta-p upstream of the break for the pump suction breaks and increases break flow

6.4.1.1.2 DESCRIPTION OF ANALYSES

The evaluation model used for the long-term LOCA mass and energy release calculations is the March 1979 model described in Reference 6.4-1. This evaluation model has been reviewed and approved generically by the Nuclear Regulatory Commission. The approval letter is included with Reference 6.4-1. Even though this is a first time application for Seabrook Station, it has also been utilized and approved on the plant-specific dockets for other Westinghouse pressurized water reactors.

This report section presents the long-term LOCA mass and energy releases generated in support of the Seabrook Station SPU. These mass and energy releases are then subsequently used in the containment integrity analysis.

6.4.1.1.3 LOCA MASS AND ENERGY (M&E) RELEASE PHASES

The containment system receives mass and energy releases following a postulated rupture in the Reactor Coolant System. These releases continue over a time period, which, for the LOCA mass and energy analysis, is divided into four phases.

1. Blowdown - the period of time from accident initiation (when the reactor is at steady state operation) to the time that the Reactor Coolant System and containment reach an equilibrium state.
2. Refill - the period of time when the lower plenum is being filled by accumulator and Emergency Core Cooling System water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment mass and energy releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of mass and energy to containment. Thus, the refill period is conservatively neglected in the mass and energy release calculation.
3. Reflood - begins when the water from the lower plenum enters the core and ends when the core is completely quenched.
4. Post-reflood (Froth) - describes the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the steam generators prior to exiting the break as steam. Later, after the broken loop steam generator cools, the break flow becomes two phase.

6.4.1.1.4 COMPUTER CODES

The Reference 6.4-1 mass and energy release evaluation model is comprised of mass and energy release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA mass and energy releases for Seabrook Station.

SATAN VI calculates blowdown, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, mass and energy flowrates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code 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 refills the reactor vessel and provides cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (LAR Subsection 6.4.1.1.8).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the steam generator heat addition calculation from the broken and intact loop steam generators.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous mass and energy release tables and mass and energy balance tables with data at critical times.

6.4.1.1.5 BREAK SIZE AND LOCATION

Generic studies have been performed with respect to the effect of postulated break size on the LOCA mass and energy releases. The double ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and froth phases, the break size has little effect on the releases.

Three distinct locations in the Reactor Coolant System loop can be postulated for pipe rupture for release purposes:

1. Hot leg (between vessel and steam generator)
2. Cold leg (between pump and vessel)
3. Pump suction (between steam generator and pump)

The break locations analyzed for Seabrook Station SPU (consistent with the UFSAR) are the double-ended pump suction rupture (10.48 ft^2), and the double-ended hot leg rupture (9.18 ft^2). Break mass and energy releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the double-ended pump suction cases. For the double-ended hot leg case, the releases were calculated only for the blowdown. The following information provides a discussion on each break location.

The double-ended hot leg rupture has been shown in previous studies to result in the highest blowdown mass and energy release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the steam generator secondary is minimal because the majority of the fluid, which exits the core, vents directly to containment bypassing the steam generators. As a result, the reflood mass and energy releases are reduced significantly as compared to either the pump suction or cold leg break locations where the core exit mixture must pass through the steam generators before venting through the break. For the hot leg break, generic studies have confirmed that there is no reflood peak (i.e., from the end of the blowdown period the containment pressure would continually decrease). Therefore, only the mass and energy releases for the hot leg break blowdown phase are calculated and presented.

The cold leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold leg break is bounded by other breaks and no further evaluation is necessary.

The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and the addition of the stored energy in the steam generators. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period by including the available energy of the Reactor Coolant System in calculating the releases to containment.

6.4.1.1.6 APPLICATION OF SINGLE-FAILURE CRITERION

An analysis of the effects of the single-failure criterion has been performed on the mass and energy release rates for each break analyzed. An inherent assumption in the generation of the mass and energy release is that offsite power is lost. This results in the actuation of the emergency diesel generators, required to power the safety injection system. This is not an issue for the blowdown period which is limited by the double-ended hot leg break.

An assessment of the limiting single failure has been made for the two double-ended pump suction cases which have long-term mass and energy release. The two cases that have been analyzed to assess the effects of a single failure are the double-ended pump suction cases with minimum and maximum Emergency Core Cooling System flows. The first case assumes minimum safeguards Safety Injection flow based on the postulated single failure of an emergency diesel generator. This results in the loss of one train of safeguards equipment. The other case assumes maximum safeguards Safety Injection flow based on no postulated failures that would impact the amount of Emergency Core Cooling System flow. The single failure for the maximum Emergency

Core Cooling System case is the loss of a spray pump. The analysis of the cases described provides confidence that the effect of credible single failures is bounded.

6.4.1.1.7 ACCEPTANCE CRITERIA FOR ANALYSES

A LBLOCA is classified as an American Nuclear Society Condition IV event, an infrequent fault. To satisfy the Nuclear Regulatory Commission acceptance criteria presented in the Standard Review Plan Section 6.2.1.3, the relevant requirements are as follows:

- 10 CFR 50, Appendix A
- 10 CFR 50, Appendix K, paragraph I.A

In order to meet these requirements, the following must be addressed.

- Sources of energy
- Break size and location
- Calculation of each phase of the accident

6.4.1.1.8 MASS AND ENERGY RELEASE DATA

Blowdown Mass and Energy Release Data

The SATAN-VI code is used for computing the blowdown transient. The 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 thermodynamic 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. The methodology for the use of this model is described in Reference 6.4-1.

LAR Table 6.4.1.1-4 presents the calculated mass and energy release for the blowdown phase of the double-ended hot leg break. For the hot leg break mass and energy release tables, break path 1 refers to the mass and energy exiting from the reactor vessel side of the break; break path 2 refers to the mass and energy exiting from the steam generator side of the break.

LAR Table 6.4.1.1-7 presents the calculated mass and energy releases for the blowdown phase of the double-ended pump suction break with minimum Emergency Core Cooling System flows. LAR Table 6.4.1.1-13 presents the calculated mass and energy releases for the blowdown phase of the double-ended pump suction break with maximum Emergency Core Cooling System flows. For the pump suction breaks, break path 1 in the mass and energy release tables refers to the mass and energy exiting from the steam generator side of the break; break path 2 refers to the mass and energy exiting from the pump side of the break.

Reflood Mass and Energy Release Data

The WREFLOOD code is used for computing the reflood transient. 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, reactor coolant pump performance, and steam generator release are included as auxiliary equations which 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 and downcomer water levels, fluid thermodynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break; i.e., the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and Emergency Core Cooling System injection water during the reflood phase has been assumed for each loop receiving Emergency Core Cooling System water. This is consistent with the usage and application of the Reference 6.4-1 mass and energy release evaluation model in recent analyses, e.g., D. C. Cook Docket [Reference 6.4-2]. Even though the Reference 6.4-1 model credits steam/water mixing only in the intact loop and not in the broken loop; the justification, applicability, and Nuclear Regulatory Commission approval for using the mixing model in the broken loop has been documented [Reference 6.4-2]. Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (i.e., thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold Emergency Core Cooling System water. The second is a single-phase mixing of condensate and Emergency Core Cooling System water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Spillage directly heats only the sump.)

The most applicable steam/water mixing test data has been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests [Reference 6.4-3], which are the largest scale data available and thus most clearly simulates the flow regimes and gravitational effects that would occur in a pressurized water reactor. These tests were designed specifically to study the steam/water interaction for pressurized water reactor reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flowrates for this group cover the phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in Reference 6.4-1. For these tests, the data clearly

indicates the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is therefore wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump suction double ended rupture break. For this break, there are two flowpaths available in the Reactor Coolant System by which mass and energy may be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the reactor coolant pump. Steam which is not condensed by Emergency Core Cooling System injection in the intact Reactor Coolant System loops passes around the downcomer and through the broken loop cold leg and pump in venting to containment. This steam also encounters Emergency Core Cooling System injection water as it passes through the broken loop cold leg, complete mixing occurs and a portion of it is condensed. It is this portion of steam which is condensed that is taken credit for in this analysis. This assumption is justified based upon the postulated break location, and the actual physical presence of the Emergency Core Cooling System injection nozzle. A description of the test and test results are contained in References 6.4-1 and 6.4-3.

LAR Tables 6.4.1.1-8 and 6.4.1.1-14 present the calculated mass and energy releases for the reflood phase of the pump suction double-ended rupture, minimum safeguards, and maximum safeguards cases, respectively. The transient response of the principal parameters during reflood are given in LAR Tables 6.4.1.1-9 and 6.4.1.1-15 for the double-ended pump suction cases.

Post-Reflood Mass and Energy Release Data

The FROTH code [Reference 6.4-4] 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 mass and energy releases that occur during this phase are superheated due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the Reactor Coolant System has equilibrated with 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 Emergency Core Cooling System 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 (see LAR Subsection 6.4.1.1.8 for additional information).

The methodology for the use of this model is described in Reference 6.4-1. The mass and energy release rates are calculated by FROTH and EPITOME until the time of containment depressurization. After containment depressurization (14.7 psia), the

mass and energy release available to containment is generated directly from core boil off/decay heat.

LAR Tables 6.4.1.1-10 and 6.4.1.1-16 present the two-phase post-reflood mass and energy release data for the pump suction double-ended cases, minimum and maximum Emergency Core Cooling System assumptions.

Decay Heat Model

On November 2, 1978, the Nuclear Power Plant Standards Committee (NUPPSCO) of the American Nuclear Society approved American Nuclear Society Standard 5.1 [Reference 6.4-5] for the determination of decay heat. This standard was used in the Mass and Energy release. Table 6.4.1.1-22 lists the decay heat curve used in the MASS AND ENERGY release analysis, post blowdown, for the Seabrook Station SPU.

Significant assumptions in the generation of the decay heat curve for use in the LOCA Mass and Energy releases analysis include the following:

1. Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
2. Decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
3. Fission rate is constant over the operating history of maximum power level.
4. The factor accounting for neutron capture in fission products has been taken from Equation 11 of Reference 6.4-5, up to 10,000 seconds and from Table 10 of Reference 6.4-5, beyond 10,000 seconds.
5. The fuel has been assumed to be at full power for 10^8 seconds.
6. The number of atoms of U-239 produced per second has been assumed to be equal to 70 percent of the fission rate.
7. The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.
8. Two-sigma uncertainty (two times the standard deviation) has been applied to the fission product decay.

Based upon Nuclear Regulatory Commission staff review, Safety Evaluation Report (SER) of the March 1979 evaluation model [Reference 6.4-1], use of the American Nuclear Society Standard-5.1, November 1979 decay heat model was approved for the calculation of mass and energy releases to the containment following a LOCA.

Steam Generator Equilibration and Depressurization

Steam generator equilibration and depressurization is the process by which secondary side energy is removed from the steam generators in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the saturation temperature (T_{sat}) at the containment design pressure. After the FROTH calculations, the EPITOME code continues the FROTH calculation for steam generator cooldown removing steam generator secondary energy at different

rates (i.e., first and second stage rates). The first stage rate is applied until the steam generator reaches T_{sat} at the user specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then the second stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken loop and intact loop steam generators are calculated separately.

During the FROTH calculations, steam generator heat removal rates are calculated using the secondary side temperature, primary side temperature and a secondary side heat transfer coefficient determined using a modified McAdam's correlation. Steam generator energy is removed during the FROTH transient until the secondary side temperature reaches saturation temperature at the containment design pressure. The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The Steam Generator energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure and that at the (lower) user specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second stage rate. The second stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user specified time of the final depressurization at 212°F. With current methodology, the secondary energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3600 seconds, i.e., 14.7 psia and 212°F.

Sources of Mass and Energy

The sources of mass considered in the LOCA mass and energy release analysis are given in LAR Tables 6.4.1.1-5, 6.4.1.1-11, and 6.4.1.1-17. These sources are the reactor coolant system, accumulators, and pumped safety injection.

The energy inventories considered in the LOCA mass and energy release analysis are given in LAR Tables 6.4.1.1-6, 6.4.1.1-12, and 6.4.1.1-18. The energy sources include:

1. Reactor Coolant System Water
2. Accumulator Water (all four inject)
3. Pumped Safety Injection Water
4. Decay Heat
5. Core Stored Energy
6. Reactor Coolant System Metal (includes steam generator tubes)
7. Steam Generator Metal (includes transition cone, shell, wrapper, and other internals)

8. Steam Generator Secondary Energy (includes fluid mass and steam mass)
9. Secondary Transfer of Energy (feedwater into and steam out of the steam generator secondary)

Energy Reference Points:

1. Available Energy: 212°F; 14.7 psia
2. Total Energy Content: 32°F; 14.7 psia

The mass and energy inventories are presented at the following times, as appropriate:

1. Time zero (initial conditions)
2. End of blowdown time
3. End of refill time
4. End of reflood time
5. Time of broken loop steam generator equilibration to pressure setpoint
6. Time of intact loop steam generator equilibration to pressure setpoint
7. Time of full depressurization (3600 seconds)

In the mass and energy release data presented, no Zirconium-water reaction heat was considered because the clad temperature is assumed not to rise high enough for the rate of the Zirconium-water reaction heat to be of significance.

The SPU LOCA mass and energy releases are lower than the mass and energy releases in the current analysis of record. This reduction is a result of three key factors. First, a generic set of LOCA mass and energies was used for the current licensing basis for Seabrook Station. The data presented in LAR Subsection 6.4.1.1 was generated with a Seabrook Station plant-specific model. Secondly, the decay heat model used in the generic data was American Nuclear Society 1971 +20%, while the analysis documented herein was performed with American Nuclear Society 1979 +2σ. Thirdly, in the SPU analysis, credit was taken for steam-water interaction in the Reactor Coolant System loop piping, which was not available when the generic data was calculated. The two methodology improvements were documented in WCAP-10325 [Reference 6.4-1] which has been reviewed and approved by the Nuclear Regulatory Commission.

The sequence of events for the LOCA transients are shown in LAR Tables 6.4.1.1-19 through 6.4.1.1-21.

6.4.1.1.9 CONCLUSIONS

The consideration of the various energy sources in the long-term mass and energy release analysis provides assurance that the available sources of energy have been included in this analysis. Thus, the review guidelines presented in Standard Review Plan Section 6.2.1.3 have been satisfied. The results of this analysis were provided for use in the containment integrity analysis, as discussed in LAR Subsection 6.4.3.

6.4.1.2 SHORT-TERM LOCA MASS AND ENERGY RELEASES

6.4.1.2.1 PURPOSE

An evaluation was conducted to determine the effect of the SPU on the short-term LOCA-related mass and energy releases that support subcompartment analyses discussed in Chapter 6.2 of the Seabrook Station UFSAR.

As documented in the Seabrook Station UFSAR Section 6.2, based upon Leak-Before-Break, reactor cavity and steam generator over-pressurization no longer need to be considered in the current licensing basis. This is based upon the final rulemaking with respect to General Design Criteria 4, dated October 27, 1987. The current licensing basis for subcompartments currently includes the pressurizer compartment and the pressurizer skirt cavity. The breaks for these subcompartments are the double-ended spray line break and the double-ended surge line break, respectively. This section discusses the short-term evaluation conducted for this program for these breaks.

6.4.1.2.2 DISCUSSION AND EVALUATION

The short-term LOCA-related mass and energy releases are used as input to the subcompartment analyses, which are performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high energy line pipe rupture within that subcompartment.

The blowdown mass and energy release rates are affected by the initial Reactor Coolant System pressure and temperature conditions. Since short-term releases are linked directly to the critical mass flux, which increases with decreasing temperatures, the short-term LOCA releases would be expected to increase due to any reductions in Reactor Coolant System coolant temperature conditions. Short term blowdown transients are characterized by a peak mass and energy release rate that occurs during a subcooled condition, thus the Zaloudek correlation, which models this condition, is currently used in the short term LOCA mass and energy release analyses with the SATAN computer program.

Double-ended Spray Line Break

Analysis was conducted for the spray line break. A SATAN IV [Reference 6.4-13] model was developed that was representative of the Seabrook specific spray line and included initial Reactor Coolant System conditions based upon the SPU parameters. This included initial Reactor Coolant System Enthalpies that were reduced by 6°F due to uncertainty and initial Reactor Coolant System pressures (2250 psia) increased by 50 psi due to uncertainty. The model also reflected specific geometric data for the pressurizer and the spray line (volume, diameter, area and length). This model was then used in computer analysis to determine the mass and energy releases.

The resulting releases were then compared to those in Seabrook UFSAR Table 6.2-30. Based upon this comparison it was shown that the current releases remained bounding for the SPU conditions.

Double-ended Surge Line Break

An evaluation was conducted for the surge line break that involved the comparison of the initial T_{hot} for the SPU to sensitivities from a generic pressurizer skirt pressurization. Since the coldest T_{hot} (604.3 °F) for the Uprate was higher than the T_{hot} (603.2 °F) used in a generic evaluation of the skirt region, the summary and conclusions of the sensitivity work applies. That is, changes to cavity pressurization force, thrust force, and jet are bounded by the original analysis.

6.4.1.2.3 RESULTS AND CONCLUSION

Seabrook Station specific mass and energy releases were generated for a postulated break in the pressurizer spray line and compared to the release presented in Seabrook Station UFSAR Table 6.2-30. Based upon the results of this comparison it is concluded that the spray line break releases in UFSAR Table 6.2-30 remain bounding for the Seabrook Station SPU.

For the surge line break that is used for the pressurizer skirt cavity analysis, changes to cavity pressurization force, thrust force, and jet impingement are bounded by the original analysis due to conservatisms in the original analysis.

6.4.2 SUB-COMPARTMENT ANALYSIS

6.4.2.1 DESCRIPTION

The evaluation of the sub-compartments is discussed in Seabrook Station UFSAR Section 6.2.1.2. The major sub-compartments within the containment are the reactor cavity, steam generator compartment, the pressurizer compartment, and the pressurizer skirt cavity. These sub-compartments are designed to withstand the differential pressures resulting from a postulated pipe break. The evaluation of the reactor cavity and the steam generator sub-compartments no longer need to be considered as part of the current licensing basis. This is based upon the final rulemaking with respect to General Design Criteria 4, dated October 27, 1987, as reported in Section 6.2.1.2 of the Seabrook Station UFSAR.

6.4.2.2 EVALUATION

The sub-compartments evaluated, at the SPU, include the pressurizer compartment and the pressurizer skirt cavity. The postulated break inside the pressurizer compartment and the pressurizer skirt cavity is the spray line full double ended guillotine rupture and the surge line full double ended guillotine rupture, respectively.

LAR Subsection 6.4.2 discusses the evaluation that was conducted to determine the effect of the SPU on the short term LOCA related mass and energy releases that support sub-compartment analyses. The evaluation determined that the current mass and energy releases as presented by Seabrook Station UFSAR Table 6.2-30 are bounding for SPU without the need to be adjusted.

6.4.2.3 CONCLUSION

The engineering evaluation has concluded that the current Seabrook Station mass and energy releases are bounding for the SPU, therefore, over pressurization of the pressurizer cubicle and pressurizer skirt cavity is bounded at SPU.

6.4.3 LOCA LONG-TERM CONTAINMENT RESPONSE

6.4.3.1 DESCRIPTION

The containment pressure and temperature response after various LOCAs is described in Seabrook Station UFSAR Section 6.2.1.1. Seabrook Station UFSAR Table 6.2.8 provides results for the existing (prior to SPU) analysis of record for containment pressure and temperature response. Existing peak containment pressure is 49.6 psig following a full double-ended rupture of the reactor coolant pump suction piping with maximum safety injection. The corresponding peak containment atmosphere temperature due to LOCA, determined to be 273°F, is less than that for the limiting main steam line break case. The results of the SPU evaluation demonstrate that the analysis of record remains bounding for peak containment pressure and temperature.

6.4.3.2 EVALUATION

Westinghouse developed mass and energy release data at SPU conditions and an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) were evaluated for the following four cases: double-ended rupture of a hot leg, with minimum and maximum safety injection; and double-ended rupture of a reactor coolant pump suction pipe, with minimum and maximum safety injection. Refer to LAR Subsection 6.4.1.1 for a description of the LOCA long-term mass and energy release data.

A model of the Seabrook Station containment and associated systems on the GOTHIC computer program was developed to calculate the containment response to LOCAs under SPU conditions. The GOTHIC model is similar to the existing CONTRAST-S-MOD1 model that was originally used to determine the Seabrook Station containment response. The primary difference between the CONTRAST and GOTHIC calculations is that the latter use revised mass and energy release rates developed by Westinghouse at the SPU conditions. Refer to LAR Section 6.4.1.1 for a description of the differences between the original and SPU LOCA mass and energy release data.

A benchmark comparison of results for a hot leg double ended rupture between the GOTHIC computer code and the existing calculation done using the CONTRAST-S-MOD-1 computer code for a power level of 3425 MWt shows the peak pressure and temperature values obtained using GOTHIC to be slightly more conservative (i.e., 38.6 vs. 37.5 psig, and 256.4 vs. 255.8°F). The same mass and energy release rates and input data used in the CONTRAST results were used in the GOTHIC calculation.

The GOTHIC containment model developed for the SPU included the same containment volume and heat structures as found in the current analysis of record except that the paint thermal conductivity on several heat sinks was decreased, which increased containment pressure and temperature responses. Consistent with the

current analysis of record, the Tagami heat transfer coefficients were utilized for condensation heat transfer to the heat sinks. The droplet diameter modeled for the break effluent was 0.004 inches while droplet diameter modeled for the containment spray was 0.002 inches, which are the recommended values specified in the GOTHIC user manual. The analysis also considered a loss of offsite power and the same limiting single failure as described in the Seabrook Station UFSAR Section 6.2.1.1, which is consistent with Standard Review Plan Section 6.2.1.1.A [Reference 6.4-12]. The inlet temperature of primary component cooling water to the residual heat removal and containment spray heat exchangers remains conservative and sensitivity analyses were performed to ensure conservative initial conditions were selected. The GOTHIC model also included the nitrogen released from the accumulators.

The SPU peak containment pressure determined using GOTHIC is 49.13 psig after a double-ended pump suction break with one safety injection train and one spray train operating. This value is less than the peak pressure for the existing (pre-SPU) conditions of 49.6 psig and the containment design pressure of 52 psig. The peak containment pressure determined in the current analysis of record is obtained for a double-ended rupture of the pump suction piping with maximum safety injection (two trains operating). The peak containment pressure obtained in the GOTHIC analysis, using the mass and energy releases for SPU conditions, is obtained for the double-ended rupture of the pump suction piping with minimum safety injection (one train operating). The LOCA case that results in highest containment pressure has changed, but the peak pressure determined in the analysis of record remains bounding. The current analysis of record was done using mass and energy releases for a generic Westinghouse plant whereas the results under SPU conditions are specific to the Seabrook Station.

The SPU peak containment atmosphere temperature post-LOCA calculated with GOTHIC is 271.0°F, which is lower than the existing post-LOCA peak containment temperature of 272.7°F.

The peak containment pressures and temperatures for the Seabrook Station containment under SPU conditions are therefore bounded by the licensing bases established with the CONTRAST code. (See LAR Figures 6.4.3-1 and 6.4.3-2).

The long-term containment temperature response obtained with the GOTHIC containment model remains bounded by the existing equipment qualification envelope. The long-term containment pressure response is bounded by the equipment qualification pressure envelope for a time period of five days. The impact of the slightly higher long term pressure, after five days on equipment qualification is evaluated in LAR Section 9.2.

Also, as part of the LOCA calculation, the SPU peak sump water temperature was determined to be 258.2°F following a double-ended pump suction break with maximum safety injection and failure of one containment spray pump. The peak sump water temperature is below the previously calculated peak of 262.5°F.

6.4.3.3 CONCLUSION

The LOCA evaluation of the Seabrook containment with the GOTHIC computer program demonstrates that the current design peak pressure and temperature remains bounding for operation at the SPU conditions. The current pressures and temperatures developed with the CONTRAST code remain the current licensing basis. The containment and associated systems will continue to meet the requirements of GDCs 16 and 50 following implementation of the SPU.

6.4.4 MAIN STEAMLINE BREAK MASS AND ENERGY RELEASES INSIDE CONTAINMENT

6.4.4.1 INTRODUCTION

Steamline ruptures occurring inside the reactor containment structure may result in significant releases of high-energy fluid to the containment environment, producing elevated containment temperatures and pressures. The magnitude of the releases following a steamline rupture is dependent upon the plant initial operating conditions and the size of the rupture as well as the configuration of the plant steam system and the containment design. These variations make it difficult to determine the absolute worst cases for either containment pressure or temperature evaluation following a steamline break. The analysis considers a variety of postulated pipe breaks encompassing wide variations in plant operation, safety system performance, and break size in determining the main steamline break mass and energy releases for use in containment analysis.

The only event other than the main steamline break that results in a breach of the secondary-side piping is the feedwater line break . The feedwater enthalpy at power is less than the enthalpy of saturated steam at the secondary-side operating pressures. Therefore, the long-term integrated energy released following a feedwater line break is bounded by the long-term integrated energy released following a main steamline break. Thus, the containment pressure and temperature responses to the mass and energy releases from a feedwater line break would be bounded by the containment responses following the main steamline break event.

6.4.4.2 INPUT PARAMETERS AND ASSUMPTIONS

The analysis inputs, assumptions, and methods pertaining to the main steamline break mass and energy releases inside containment are presented in this section.

To determine the effects of plant power level and break area on the mass and energy releases from a ruptured steamline, spectra of both variables have been evaluated. At plant power levels of 100 percent, 70 percent, 30 percent, and near 0 percent of the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), two break sizes have been defined. These break areas are defined as the following.

1. A full double-ended rupture downstream of the flow restrictor in one steamline. Note that a double-ended rupture is defined as a rupture in which the steam pipe is completely severed and the ends of the break fully displace from each other. The full

double-ended rupture represents the largest break of the main steamline producing the highest mass flowrate from the faulted-loop steam generator.

2. A small split rupture that will neither generate a steamline isolation signal from the Westinghouse Solid-State Protection System nor result in water entrainment in the break effluent. Reactor protection and safety injection actuation functions are obtained from containment pressure signals.

The 24 cases included in the Seabrook Station analysis for the SPU have been chosen based on the selection of similar steamline ruptures included in the analyses presented in the Seabrook Station UFSAR Subsection 6.2.1.4. The cases have been analyzed at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Other assumptions regarding important plant conditions and features are discussed in the following paragraphs.

Initial Power Level

Steamline breaks can be postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Since steam generator water mass decreases with increasing power level, breaks occurring at lower power levels will generally result in a greater total mass release to the containment. However, because of increased stored energy in the primary side of the plant, increased heat transfer in the steam generators, and additional energy generation in the fuel, the energy release to the containment from breaks postulated to occur during full-power, or near full-power, operation may be greater than for breaks occurring with the plant in a low-power, or hot-shutdown, condition. Additionally, pressure in the steam generators changes with increasing power and has a significant influence on the rate of blowdown.

Because of the opposing effects on mass versus energy release for the main steamline break due to a change in initial power level, a single power level cannot be specified as the worst case for either the containment pressure response or the containment temperature response. Therefore, conditions associated with representative power levels including 100 percent, 70 percent, 30 percent, and near 0 percent of the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) have been evaluated for Seabrook Station based on the information in Reference 6.4-6. Reference 6.4-1 has been reviewed and approved by the Nuclear Regulatory Commission for use in main steamline break analysis inside containment.

In general, the plant initial conditions are assumed to be at the nominal value corresponding to the initial power for that case, with appropriate uncertainties included. LAR Tables 6.4.4.1-1 and 6.4.4.1-2 identify the values assumed for NSSS power, Reactor Coolant System pressure, Reactor Coolant System vessel average temperature, Reactor Coolant System flow, pressurizer water volume, steam generator water level, steam generator temperature and pressure, and feedwater enthalpy corresponding to each power level analyzed. Steamline break mass and energy releases assuming an Reactor Coolant System average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window. At the high end, there is more mass and energy available for release into containment. The thermal design flowrate has been used for the Reactor Coolant

System flow input consistent with the assumptions documented in Reference 6.4-6. The thermal design flowrate is also consistent with other main steamline break analysis assumptions related to nonstatistical treatment of uncertainties, as well as Reactor Coolant System thermal-hydraulic inputs related to pressure drops and rod drop time.

Uncertainties on the initial conditions assumed in the analysis for the SPU have been applied only to the Reactor Coolant System average temperature (6.0°F) and the steam generator mass (8.0 percent narrow-range span). The calorimetric uncertainty associated with power has been included in the value for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Nominal values are adequate for the initial conditions associated with pressurizer pressure and pressurizer water level. Uncertainty conditions are only applied to those parameters that could increase the amount of mass or energy discharged into containment.

Single-Failure Assumptions

Various single failures have been identified and used in the spectrum of main steamline break cases analyzed, consistent with the standard approach for licensing-basis analyses. Most cases analyzed consider only one single failure. One of these failures is considered as part of the containment response analysis. The postulated single failures (discussed also in Reference 6.4-6) that increase the main steamline break mass and energy releases to containment are discussed below.

a. Failure of the Main Steam Isolation Valve in the Faulted Loop

   The main steamline isolation function is accomplished via the main steamline isolation valve in each of the four steamlines. Each valve closes on an isolation signal to terminate steam flow from the associated steam generator. The main steamline rupture upstream of this valve, as postulated for the inside-containment analysis, creates a situation in which the steam generator on the faulted loop cannot be isolated, even when the main steamline isolation valve successfully closes. The break location allows a continued blowdown from the faulted-loop steam generator until it is empty and the sources of feedwater and emergency feedwater addition are terminated. If the faulted-loop main steamline isolation valve fails to close, blowdown from more than one steam generator is terminated by the closure of the corresponding main steam isolation valve for each intact-loop steam generator. Therefore, there is no failure of a single main steam isolation valve that could cause continued blowdown from multiple steam generators.

   In addition to the continued blowdown from the faulted-loop steam generator after main steam isolation valve closure, the steam in the non-isolable sections of the main steam system need to be considered. The main steam isolation valve failure impacts the mass and energy releases since a failed main steam isolation valve will result in a larger non-isolable steamline volume.

b. Failure of the Main Feedwater Isolation Valve in the Faulted Loop

   If the main feedwater isolation valve in the feedwater line to the faulted steam generator is assumed to fail in the open position, backup isolation is provided via the main feedwater flow control valve closure. The additional inventory between the

main feedwater isolation valve and the flow control valve in the faulted loop would be available to be released to containment.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture results in large amounts of water being added to the steam generators through the main feedwater system. Rapid-closing main feedwater isolation valve s or flow control valves in the main feedwater lines limit this effect. The feedwater addition that occurs prior to closing of the main feedwater isolation valve or flow control valve influences the steam generator blowdown in several ways. First, because the water entering the steam generator is subcooled, it lowers the steam pressure thereby reducing the flowrate out of the break. As the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolation valves will flash into the steam generators providing additional secondary fluid which may exit out of the rupture. Secondly, the increased flow causes an increase in the total heat transfer from the primary to secondary systems resulting in greater integrated energy being released out of the break.

Following the initiation of the main steamline break, main feedwater flow is conservatively modeled by assuming that sufficient feedwater flow is provided to match or exceed the steam flow prior to reactor trip, as shown in LAR Table 6.4.4.1-3. The initial increase in feedwater flow (until fully isolated) is in response to the feedwater pump control valve opening up in response to the steam flow/feedwater flow mismatch, or the decreasing steam generator water level as due to a lower backpressure on the feedwater pump as a result of the depressurizing steam generator. This maximizes the total mass addition prior to feedwater isolation. The feedwater isolation response time, following the safety injection signal, is assumed to be a total of 11 seconds, accounting for delays associated with signal processing plus main feedwater isolation valve stroke time. For the circumstance in which the main feedwater isolation valve in the faulted loop fails to close, there is no effect on the feedwater isolation response time since the total delay for the flow control valve closure is also 11 seconds.

Following feedwater isolation, as the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolation or control valve may flash to steam if the feedwater temperature exceeds the saturation temperature. This non-isolable feedwater line volume is an additional source of fluid that can increase the mass discharged out of the break. The non-isolable volume in the feedwater lines is maximized for the faulted loop. Feedwater line piping volumes available for steam flashing in this analysis are shown in LAR Table 6.4.4.1-3.

Steamline break mass and energy releases assuming a main feedwater temperature at the high end of the feedwater temperature window are conservative with respect to similar releases at the low end of the feedwater temperature window. At the high end, there is more energy available for release into containment.

Emergency Feedwater System

Generally, within the first minute following a steamline break, the Emergency Feedwater System is initiated on any one of several protection system signals. Addition of

emergency feedwater to the steam generators will increase the secondary mass available for release to containment as well as increase the heat transferred to the secondary fluid. The emergency feedwater flow to the faulted steam generator has been assumed to be a constant value consistent with all emergency feedwater pumps operating. For the double-ended rupture cases, emergency feedwater flow is assumed to be automatically isolated within 100 seconds due to high flow through the branch line to the faulted-loop steam generator. For the split-break cases, emergency feedwater flow to the faulted-loop steam generator has been assumed up until the time of operator action at 30 minutes after event initiation to isolate the flow to the steam generator near the break location. Emergency feedwater system assumptions that have been used in the analysis are presented in LAR Table 6.4.4.1-3.

Steam Generator Fluid Mass

A maximum initial steam generator mass in the faulted-loop steam generator has been used in the analyzed cases. The use of a high faulted-loop initial steam generator mass maximizes the steam generator inventory available for release to containment. The initial mass has been calculated as the value corresponding to the programmed level +8.0 percent narrow-range span and assuming 0 percent tube plugging. This assumption is conservative with respect to the Reactor Coolant System cooldown through the faulted-loop steam generator resulting from the steamline break.

Steam Generator Reverse Heat Transfer

Once the steamline isolation is complete, the steam generators in the intact loops may become sources of energy that can be transferred to the steam generator with the broken steamline. This energy transfer occurs via the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes could drop below the temperature of the secondary fluid in the intact steam generators, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. When applicable, the effects of reverse steam generator heat transfer are included in the results.

Break Flow Model

Piping discharge resistances are not included in the calculation of the releases resulting from the steamline ruptures (Moody Curve for an f (ℓ / D) = 0 is used). This is consistent with the expectations of the Nuclear Regulatory Commission as presented in Section 6.2.1.4 of the Standard Review Plan, NUREG-0800, Revision 1. No entrainment is assumed in the break effluent. The assumption of saturated steam being released for all break types is a conservative assumption that maximizes the energy release into containment.

Steamline Volume Blowdown

The contribution from the secondary plant steam piping is included in the mass and energy release calculations. The flowrate is determined using the Moody correlation, the pipe cross-sectional area, and the initial steam pressure. For the steamline break cases analyzed for the SPU, the non-isolable steamline mass is included in the mass exiting the break from the time of steamline isolation until the non-isolable mass is

completely released to containment. The steam piping volume assumed in the analysis is 974 ft^3 with no main steam isolation valve failure and 6,179 ft^3 assuming an main steam isolation valve failure in the faulted-loop steamline.

Main Steamline Isolation

Steamline isolation is assumed in all four loops to terminate the blowdown from the three intact steam generators. A delay time of 6 seconds, accounting for delays associated with signal processing plus main steam isolation valve stroke time, with unrestricted steam flow through the valve during the valve stroke, has been assumed.

Protection System Actuations

The protection systems available to mitigate the effects of a main steamline break inside containment include reactor trip, safety injection, steamline isolation, and feedwater isolation. The protection system actuation signals and associated setpoints that have been modeled in the analysis are identified in LAR Table 6.4.4.1-4. The setpoints used are conservative values with respect to the plant-specific values delineated in the Technical Specifications.

Safety Injection System

Minimum Safety Injection System flowrates corresponding to the failure of one Safety Injection System train have been assumed in this analysis. A minimum Safety Injection flow is conservative since the reduced boron addition maximizes a return to power resulting from the Reactor Coolant System cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. The delay time to achieve full safety injection flow is assumed to be 27 seconds for this analysis with offsite power available. A coincident loss of offsite power is not assumed for the analysis of the steamline break inside containment since the mass and energy releases would be reduced due to the loss of forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

Reactor Coolant System Metal Heat Capacity

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, the reactor coolant pumps, and the steam generator thick-metal mass and tubing. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. The effects of this Reactor Coolant System metal heat are included in the results using conservative thick-metal masses and heat transfer coefficients.

Core Decay Heat

Core decay heat generation assumed in calculating the steamline break mass and energy releases is based on the 1979 American Nuclear Society Decay Heat + 2σ model as presented in ANSI/ANS-5.1-1979 [Reference 6.4-5].

Rod Control

The rod control system is conservatively assumed to be in manual operation for the steamline break analyses. If the reactor was in automatic rod control, the rods would

withdraw to maintain nominal average temperature prior to reactor trip. Assuming that the reactor is in manual rod control allows for a greater Reactor Coolant System cooldown prior to the reactor trip signal, which maximizes the reactivity feedback at end-of-cycle conditions and produces a greater post-trip power increase.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle conditions are used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reactivity feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

Description of Analyses and Evaluations

The system transient that provides the break flows and the energy release rates from the steamline break inside containment has been analyzed with the RETRAN [Reference 6.4-7] computer code. Blowdown mass and energy releases determined using RETRAN include the effects of core power generation, main and emergency feedwater additions, engineered safeguards systems, reactor coolant system thick-metal heat storage including steam generator thick-metal mass and tubing, and reverse steam generator heat transfer. The use of the RETRAN code for the analysis of the main steamline break mass and energy releases inside containment is documented in WCAP-14882-P-A [Reference 6.4-8], which has been reviewed and approved by the Nuclear Regulatory Commission for use in Westinghouse non-LOCA safety analyses. As noted in Reference 6.4-4, no entrainment is assumed in the break effluent. The assumption of saturated steam being released from the break location is a conservative assumption that maximizes the energy release into containment. The Seabrook Station NSSS has been analyzed to determine the transient mass releases and the energy release rates inside containment following a steamline break event. The tables of mass and energy releases are used as input conditions to the analysis of the containment response.

The following licensing-basis cases of the main steamline break inside containment have been analyzed at the noted conditions for the SPU.

- Full double-ended (1.388 ft^2) rupture at 100 percent power – no single failure in main steamline break transient
- Full double-ended (1.388 ft^2) rupture at 100 percent power – main steam isolation valve failure
- Full double-ended (1.388 ft^2) rupture at 100 percent power – main feedwater isolation valve failure
- 1.172 ft^2 split rupture at 100 percent power – no single failure in main steamline break transient
- 1.172 ft^2 split rupture at 100 percent power – main steam isolation valve failure
- 1.172 ft^2 split rupture at 100 percent power – main feedwater isolation valve failure

- Full double-ended (1.388 ft^2) rupture at 70 percent power – no single failure in main steamline break transient
- Full double-ended (1.388 ft^2) rupture at 70 percent power – main steam isolation valve failure
- Full double-ended (1.388 ft^2) rupture at 70 percent power – main feedwater isolation valve failure
- 1.175 ft^2 split rupture at 70 percent power – no single failure in main steamline break transient
- 1.175 ft^2 split rupture at 70 percent power – main steam isolation valve failure
- 1.175 ft^2 split rupture at 70 percent power – main feedwater isolation valve failure
- Full double-ended (1.388 ft^2) rupture at 30 percent power – no single failure in main steamline break transient
- Full double-ended (1.388 ft^2) rupture at 30 percent power – main steam isolation valve failure
- Full double-ended (1.388 ft^2) rupture at 30 percent power – main feedwater isolation valve failure
- 1.170 ft^2 split rupture at 30 percent power – no single failure in main steamline break transient
- 1.170 ft^2 split rupture at 30 percent power – main steam isolation valve failure
- 1.170 ft^2 split rupture at 30 percent power – main feedwater isolation valve failure
- Full double-ended (1.388 ft^2) rupture at 2 percent power – no single failure in main steamline break transient
- Full double-ended (1.388 ft^2) rupture at 2 percent power – main steam isolation valve failure
- Full double-ended (1.388 ft^2) rupture at 2 percent power – main feedwater isolation valve failure
- 1.086 ft^2 split rupture at 2 percent power – no single failure in main steamline break transient
- 1.086 ft^2 split rupture at 2 percent power – main steam isolation valve failure
- 1.086 ft^2 split rupture at 2 percent power – main feedwater isolation valve failure

For the double-ended rupture cases, the forward-flow cross-sectional area from the faulted-loop steam generator is limited by the integral flow restrictor area of 1.388 ft^2, which is less than the actual area of 3.903 ft^2 for the reverse-direction cross-sectional flow area of the piping inside containment. The full double-ended rupture represents the break producing the highest mass flowrate from the faulted-loop steam generator. Smaller double-ended rupture break sizes are represented by a reduction in the initial

steam blowdown rate at the time of the break. Therefore, no other double-ended rupture break sizes have been considered other than the full double-ended rupture.

For the split-break main steamline break cases, the break area is smaller than the area of a single integral flow restrictor. The flowrate from all steam generators prior to main steam isolation valve closure and the flowrate from a single steam generator after main steam isolation valve closure supply the steam flow to the break. The cross-sectional split-rupture areas have been redefined based on the Seabrook Station specific values for the secondary-side protection system setpoints incorporated into the RETRAN NSSS model. Each break size as a function of power is the largest area that does not produce a steamline isolation signal from the Westinghouse Solid State Protection System nor results in water entrainment in the break effluent as discussed in Reference 6.4-1.

6.4.4.3 ACCEPTANCE CRITERIA

The main steamline break is classified as an American Nuclear Society Condition IV event, an infrequent fault. The acceptance criteria associated with the steamline break event resulting in a mass and energy release inside containment is based on an analysis that provides sufficient conservatism to show that the containment design margin is maintained. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, the break flow model, main and emergency feedwater flow, steamline and feedwater isolation, and single failure such that the containment peak pressure and temperature are maximized. These analysis assumptions have been included in this steamline break mass and energy release analysis as discussed in Reference 6.4-6 and LAR Subsection 6.4.4.2.

6.4.4.4 RESULTS

The steamline break mass and energy release analysis of record for Seabrook Station is a generic analysis for plants with Westinghouse Model F steam generators. The inputs to the generic analysis are not plant-specific for Seabrook Station. The analysis was performed using a computer code that is no longer technically supported by Westinghouse.

The SPU analysis uses the RETRAN code to model the steamline break transient response. Also, the analysis inputs and assumptions are plant-specific for Seabrook Station as defined for the SPU conditions. Thus, the methodology change to RETRAN and the use of plant-specific inputs resulted in changes to the mass and energy releases beyond those due to the SPU power increases alone.

Using the main steamline break analysis methodology documented in Reference 6.4-1 as a basis, including Seabrook Station specific parameter changes associated with the SPU, the mass and energy release rates for each of the steamline break cases noted in LAR Subsection 6.4.4.2 have been developed for use in containment pressure and temperature response analyses discussed in LAR Subsection 6.4.5. LAR Table 6.4.4.1-5 provides the sequence of events for each of the 24 steamline break sizes analyzed for Seabrook Station SPU.

For the double-ended rupture main steamline break at all power levels, the first protection system signal actuated is Low Steamline Pressure (2-of-3 channels per loop, lead/lag compensated in each channel) in any loop that initiates steamline isolation and safety injection; the safety injection signal produces a reactor trip signal. Feedwater system isolation and emergency feedwater actuation occur as a result of the safety injection signal.

For the split-rupture steamline breaks at all power levels, no mitigation signal is received from any secondary-side signal produced by the Engineered Safety Features Actuation System. The first protection system signal actuated is assumed to be the High-1 Containment Pressure (2-of-3 channels), which initiates safety injection; the safety injection signal produces a reactor trip signal. Feedwater system isolation and emergency feedwater actuation occur as a result of the safety injection signal. Steamline isolation is initiated following receipt of the High-2 Containment Pressure (2-of-3 channels) signal.

The turbine stop valve is assumed to close instantly following the reactor trip signal; the delay time used in the steamline break mass and energy releases inside containment is 0.0 seconds.

6.4.4.5 CONCLUSIONS

The mass and energy releases from the 24 steamline break cases inside containment have been analyzed at the conditions defined by the SPU. The assumptions delineated in LAR Subsection 6.4.4.2 have been included in the steamline break analysis such that conservative mass and energy releases are calculated. The steam mass and energy releases discussed in this section have been provided for use in the containment response analysis in LAR Subsection 6.4.5.

6.4.5 STEAMLINE BREAK CONTAINMENT RESPONSE

6.4.5.1 DESCRIPTION

The containment pressure and temperature response following various main steam line breaks is described in Seabrook Station UFSAR Section 6.2.1. Seabrook Station UFSAR Tables 6.2-13 and 6.2-14 provide results for the existing analyses of record for containment pressure and temperature response. Under existing conditions, peak containment temperature is determined to be 364°F following a main steam line break at 100% power with failure of one emergency diesel generator. The existing peak pressure following a main steamline break is 36.1 psig determined for a double-ended rupture of the main steam line at hot standby with failure of one spray train.

Re-evaluation of steam line breaks inside containment under SPU conditions demonstrates that the analysis of record remains bounding for peak containment temperature. The main steamline break peak containment pressure, under SPU conditions, is bounded by the existing LOCA pressure analysis. Predicted pressures and temperatures remain enveloped by the existing environmental qualification curves.

6.4.5.2 EVALUATION

The Westinghouse-developed mass and energy release data for an analyzed nuclear steam supply system power of 3678 MWt were evaluated for twelve main steam line double-ended rupture cases and twelve main steam line split break cases. Power levels considered included 100%, 70%, 30%, and near zero of the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Single failures assumed include a main steam isolation valve, a main feedwater isolation valve, or the start-up of a diesel generator after loss of offsite power.

A single node model of the Seabrook Station containment and associated systems on the GOTHIC computer program was developed to calculate containment response to main steam line breaks under SPU conditions. The GOTHIC model is similar to the existing CONTRAST-S-MOD1 model that was originally used to determine the Seabrook Station containment response. The primary difference between the CONTRAST and GOTHIC calculations is that the latter uses revised mass and energy release rates determined for the SPU conditions.

The mass and energy release data determined by Westinghouse utilized containment isolation signals that were calculated from the GOTHIC pressure response in an iterative manner. Main steam line break release rates were determined by Westinghouse assuming, for conservatism, that offsite power is not lost. Refer to LAR Subsection 6.4.4 for a description of the steam line break mass and energy release data.

The containment volume and heat structures in the GOTHIC model are the same as in the approved analysis of record except that the paint thermal conductivity on several heat sinks was decreased, which increased the containment pressure and temperature responses. The conservative Uchida heat transfer correlations with 8% re-vaporization, as allowed by NUREG 0588, are utilized for the main steam line break cases. The droplet diameter of break effluent is taken as 0.004 inch, and that of containment spray is taken as 0.002 inch, which are the recommended values specified in the GOTHIC user manual. The inlet temperature of primary component cooling water to the residual heat removal and containment spray heat exchangers remains conservative, and sensitivity analyses were performed to ensure conservative initial conditions were selected.

The existing peak containment temperature resulting from a main steam line break inside is 364°F for a full double ended rupture of the main steam line from 100% power with failure of the main steam isolation valve.

Under SPU conditions using the GOTHIC model and credit for 8 percent re-vaporization, the highest peak containment temperature was determined to be 357.4°F for a full double ended rupture of the main steam line at 100% power with failure of one emergency diesel generator (one train of emergency cooling). The peak containment temperature under SPU conditions for a steam line break is therefore bounded by the existing analysis of record.

The existing peak pressure during main steamline break is 36.1 psig determined for a double-ended rupture of the main steam line at hot standby power with failure of one spray train. This peak containment pressure determined for main steamline break conditions is well below the peak containment pressure determined under LOCA conditions of 49.6 psig following a full double-ended rupture of the reactor coolant pump suction piping with two trains of safety injection in operation. Refer to LAR Subsection 6.4.3.

The highest peak pressure under SPU conditions following a main steamline break is calculated to be 37.3 psig for a doubled ended rupture at near zero power with failure of one diesel generator (i.e., one train). Peak containment pressure of 30.8 psig is developed for main steamline break under SPU conditions for the double-ended rupture at 100% power with failure of one train. The peak pressure for main steamline break has changed from the double-ended rupture at near zero power (hot standby) to the double-ended rupture at 100% power under SPU conditions. The current analysis of record was done using mass and energy release data for a generic Westinghouse plant whereas the results under SPU conditions are specific to Seabrook Station. Although the peak containment pressure resulting from main steamline break under SPU conditions is slightly higher than that developed in the analysis of record, this value remains bounded by the peak pressures determined by the LOCA analysis. Refer to LAR Subsection 6.4.3.

The peak containment pressures and temperatures for the Seabrook Station containment under SPU conditions are therefore bounded by the licensing bases established with the CONTRAST code. Refer to LAR Figures 6.4.5-1 and 6.4.5-2.

The long-term containment pressure and temperature response obtained with the GOTHIC containment model remains bounded by the existing equipment qualification envelope.

6.4.5.3 CONCLUSION

The existing peak containment temperature and pressure resulting from a main steam line break inside the Seabrook Station containment remains bounding for operation at SPU conditions. A GOTHIC computer model of the containment was utilized to analyze twelve double ended rupture cases and twelve split breaks. Power levels of 100%, 70%, 30% and near zero and single failures of a main steam isolation valve, a feedwater isolation valve or loss of an emergency diesel generator were evaluated based on mass and energy release data provided by Westinghouse. Results from the GOTHIC model showed that a double ended rupture from 100% power with failure of a diesel generator yields a peak containment temperature of 357.4°F which is less than the pre-uprate calculated peak temperature of 364°F and well below the containment equipment qualification envelope of 375°F. Containment pressures calculated for SPU conditions remain bounded. The containment and associated systems will continue to meet the requirements of GDCs 16 and 50 following implementation of the SPU.

TABLE 6.4.1.1-1
SYSTEM PARAMETERS
INITIAL CONDITIONS FOR SPU

Parameters	Value
Core Thermal Power (MWt)	3659
Reactor Coolant System Total Flowrate (lbm/sec)	38,722.22
Vessel Outlet Temperature (°F)	627.4
Core Inlet Temperature (°F)	562.8
Vessel Average Temperature (°F)	595.1
Initial Steam Generator Steam Pressure (psia)	985
Steam Generator Tube Plugging (%)	0
Initial Steam Generator Secondary Side Mass (lbm)	128737
Assumed Maximum Containment Backpressure (psia)	66.7
Accumulator Water Volume (ft^3) per accumulator Nitrogen Cover Gas Pressure (psia) Temperature (°F)	 892.1 600 120
Safety Injection Delay, total (sec) with loss of offsite power(from beginning of event) (Minimum Emergency Core Cooling Systems case) (Maximum Emergency Core Cooling Systems case)	 30.0 5.0

Note: Core Thermal Power, Reactor Coolant System Total Flowrate, Reactor Coolant System Coolant Temperatures, and Steam Generator Secondary Side Mass include appropriate uncertainty and/or allowance.

TABLE 6.4.1.1-2
SAFETY INJECTION FLOW
MINIMUM SAFEGUARDS

Reactor Coolant System Pressure (psia)	Total Flow (gpm)
Injection Mode (Reflood Phase)	
15.0	5129.0
115.0	3653.5
200.0	884.19
Injection Mode (Post-Reflood Phase)	
66.7	4366.17
Cold Leg Recirculation Mode	
66.7	552.44 Lbm/Sec
Hot Leg Recirculation Mode	
66.7	534.97 Lbm/Sec

TABLE 6.4.1.1-3
SAFETY INJECTION FLOW
MAXIMUM SAFEGUARDS

Reactor Coolant System Pressure (psia)	Total Flow (gpm)
Injection Mode (Reflood Phase)	
15.0	6400.3
115.0	4874.3
215.0	2127.4
Injection Mode (Post-Reflood Phase)	
66.7	5611.36
Cold Leg Recirculation Mode	
66.7	906.01 Lbm/Sec
Hot Leg Recirculation Mode	
66.7	946.49 Lbm/Sec

TABLE 6.4.1.1-4
DOUBLE-ENDED HOT LEG BREAK
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
Time (Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)
.00000	.0	.0	.0	.0
.00110	47825.7	31191.0	47823.9	31188.5
.101	42298.3	27851.3	27843.2	18118.0
.201	37272.7	24510.4	23780.2	15359.7
.302	35778.9	23507.0	21332.2	13580.6
.402	34740.5	22808.2	20116.0	12582.6
.502	34248.8	22473.5	19390.6	11926.8
.602	34166.4	22425.5	18924.9	11473.3
.701	33729.4	22182.0	18553.0	11111.7
.801	32975.9	21761.4	18297.5	10847.0
.902	32276.3	21396.9	18130.0	10655.3
1.00	31968.8	21309.4	17973.7	10487.4
1.10	31648.6	21218.2	17952.2	10407.4
1.20	31205.7	21040.1	17987.3	10368.4
1.30	30613.4	20754.5	18069.4	10363.2
1.40	29998.1	20441.9	18173.2	10377.3
1.50	29484.1	20190.5	18287.7	10403.8
1.60	29050.0	19991.2	18402.8	10436.5
1.70	28548.5	19739.4	18503.8	10467.2
1.80	27933.0	19398.2	18579.7	10489.2
1.90	27285.6	19025.4	18636.8	10505.1
2.00	26721.8	18706.3	18675.8	10515.1
2.10	26213.3	18424.0	18698.6	10519.1
2.20	25714.9	18141.8	18700.3	10514.1
2.30	25183.2	17823.3	18683.7	10501.0
2.40	24648.1	17489.4	18648.4	10479.2
2.50	24174.6	17196.2	18600.5	10451.6
2.60	23738.3	16925.2	18542.1	10419.0
2.70	23317.8	16655.6	18472.6	10381.0

NOTES:
1. Mass and energy exiting from the reactor vessel side of the break
2. Mass and energy exiting from the steam generator side of the break

TABLE 6.4.1.1-4 (continued)
DOUBLE-ENDED HOT LEG BREAK
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
Time (Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)
2.80	22934.0	16404.8	18395.6	10339.2
2.90	22560.9	16151.3	18310.2	10293.1
3.00	22219.6	15913.8	18216.6	10242.8
3.10	21922.3	15703.7	18120.7	10191.3
3.20	21643.0	15498.5	18017.2	10135.8
3.30	21394.1	15310.7	17910.1	10078.4
3.40	21163.6	15130.4	17797.9	10018.2
3.50	20962.1	14966.4	17682.3	9956.3
3.60	20781.9	14814.2	17562.1	9892.1
3.70	20630.2	14680.2	17439.8	9826.8
3.80	20511.1	14568.4	17313.1	9759.3
3.90	20438.1	14490.7	17184.7	9690.9
4.00	20375.5	14419.9	17055.3	9622.3
4.20	20225.6	14266.9	16798.9	9486.9
4.40	20070.4	14141.6	16540.5	9351.1
4.60	19903.5	14022.6	16310.2	9232.3
4.80	19737.7	13902.3	16045.9	9094.2
5.00	19651.7	13807.4	15586.7	8845.8
5.20	19658.7	13750.6	15223.7	8656.0
5.40	19710.8	13709.4	14853.0	8463.0
5.60	19809.4	13677.6	14448.0	8250.6
5.80	19961.8	13666.2	14106.7	8074.6
6.00	20179.3	13685.7	13697.0	7857.6
6.20	20437.5	13721.9	13300.3	7647.5
6.40	20757.0	13788.6	12928.3	7450.5
6.60	21152.9	13901.4	12577.7	7264.3
6.80	15571.3	11360.9	12235.1	7080.9
7.00	15708.4	11376.4	11911.3	6906.8

NOTES:
1. Mass and energy exiting from the reactor vessel side of the break
2. Mass and energy exiting from the steam generator side of the break

TABLE 6.4.1.1-4 (continued)
DOUBLE-ENDED HOT LEG BREAK
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
Time (Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)
7.20	15777.0	11319.0	11637.6	6760.4
7.40	15918.5	11375.3	11359.7	6608.9
7.60	15995.0	11352.8	11075.9	6453.2
7.80	16094.4	11342.2	10813.7	6309.5
8.00	16204.8	11307.7	10559.5	6169.9
8.20	16260.5	11292.0	10308.0	6031.6
8.40	16358.8	11279.7	10057.9	5894.0
8.60	16281.5	11183.3	9813.7	5760.2
8.80	16202.6	11051.9	9570.3	5627.0
9.00	16334.5	11055.7	9326.3	5493.9
9.20	16457.5	11060.0	9088.0	5364.7
9.40	16571.7	11063.6	8852.3	5237.2
9.60	16668.7	11061.0	8616.8	5110.2
9.80	16733.7	11045.0	8383.4	4984.7
10.0	16724.0	10991.5	8151.2	4860.6
10.2	16486.8	10815.3	7918.8	4736.9
10.2	16480.4	10811.1	7915.4	4735.0
10.4	15843.1	10419.5	7689.8	4615.6
10.6	15163.0	10011.9	7467.6	4498.8
10.8	14821.2	9792.7	7251.1	4385.8
11.0	14690.5	9693.9	7044.3	4278.5
11.2	14626.4	9637.5	6849.4	4177.8
11.4	14562.7	9585.8	6663.2	4081.6
11.6	14462.6	9516.8	6482.5	3988.4
11.8	14266.3	9396.0	6310.8	3899.7
12.0	13862.4	9160.5	6142.7	3813.1
12.2	13265.5	8818.2	5977.6	3728.3
12.4	12774.0	8535.2	5814.7	3645.1

NOTES:
1. Mass and energy exiting from the reactor vessel side of the break
2. Mass and energy exiting from the steam generator side of the break

TABLE 6.4.1.1-4 (continued)
DOUBLE-ENDED HOT LEG BREAK
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
Time (Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)
12.6	12491.6	8369.9	5662.2	3567.9
12.8	12298.8	8259.5	5514.2	3493.3
13.0	12119.5	8162.5	5374.9	3423.1
13.2	11918.5	8058.5	5243.5	3356.5
13.4	11665.6	7928.7	5115.1	3291.1
13.6	11343.7	7761.5	4990.2	3227.3
13.8	10968.7	7565.5	4869.8	3166.1
14.0	10583.4	7363.9	4749.5	3105.2
14.2	10242.2	7189.6	4630.9	3045.6
14.4	9952.3	7048.2	4516.9	2988.6
14.6	9686.0	6926.0	4405.4	2933.0
14.8	9423.0	6810.1	4298.0	2879.3
15.0	9095.8	6630.0	4194.6	2827.8
15.2	8660.3	6281.8	4084.7	2771.9
15.4	7584.9	5961.5	3965.7	2711.4
15.6	6786.5	5752.8	3819.3	2639.7
15.8	6214.4	5483.9	3643.0	2558.5
16.0	5654.6	5167.5	3437.0	2468.4
16.2	5112.1	4834.3	3207.1	2370.8
16.4	4647.8	4539.4	2962.6	2269.9
16.6	4238.5	4279.7	2717.6	2170.2
16.8	3883.0	4034.5	2482.6	2074.6
17.0	3570.4	3822.7	2268.3	1985.9
17.2	3300.5	3634.2	2082.5	1908.3
17.4	3072.9	3462.2	1916.6	1836.4
17.6	2885.2	3302.9	1782.4	1774.8
17.8	2712.5	3139.1	1662.4	1717.7
18.0	2534.1	2965.7	1563.2	1665.3

NOTES:
1. Mass and energy exiting from the reactor vessel side of the break
2. Mass and energy exiting from the steam generator side of the break

TABLE 6.4.1.1-4 (continued)
DOUBLE-ENDED HOT LEG BREAK
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
Time (Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)	Flow (Lbm/Sec)	Energy Thousand (Btu/Sec)
18.2	2343.1	2779.3	1476.5	1621.3
18.4	2147.3	2574.0	1391.7	1574.3
18.6	1966.9	2375.3	1324.1	1525.4
18.8	1786.4	2170.6	1261.5	1475.7
19.0	1628.5	1992.1	1205.5	1436.8
19.2	1502.1	1851.1	1116.5	1352.2
19.4	1437.8	1785.0	1049.8	1283.0
19.6	1366.9	1707.3	993.8	1219.9
19.8	1276.8	1598.6	949.1	1168.4
20.0	1178.7	1480.7	916.5	1130.1
20.2	1096.0	1377.9	892.2	1101.3
20.4	1019.9	1282.3	863.7	1067.4
20.6	925.3	1163.2	799.6	990.1
20.8	843.1	1062.9	704.4	874.4
21.0	744.5	939.0	657.2	818.0
21.2	663.5	838.2	562.0	699.2
21.4	578.9	732.1	459.8	574.3
21.6	502.2	635.4	330.6	413.7
21.8	455.6	577.0	237.8	298.9
22.0	431.2	546.9	159.6	201.7
22.2	.0	.0	51.0	64.8
22.4	.0	.0	.0	.0

NOTES:
1. Mass and energy exiting from the reactor vessel side of the break
2. Mass and energy exiting from the steam generator side of the break

TABLE 6.4.1.1-5
DOUBLE-ENDED HOT LEG BREAK MASS BALANCE
SEABROOK STATION SPU

Time (Seconds)		.00	22.40	22.40+δ
		Mass (Thousand lbm)		
Initial	In Reactor Coolant System and Accumulators	728.35	728.35	728.35
Added Mass	Pumped Injection	.00	.00	.00
	Total Added	.00	.00	.00
*** TOTAL AVAILABLE ***		728.35	728.35	728.35
Distribution	Reactor Coolant	507.63	60.14	92.48
	Accumulator	220.72	175.62	143.28
	Total Contents	728.35	235.76	235.76
Effluent	Break Flow	.00	492.56	492.56
	Emergency Core Cooling Systems Spill	.00	.00	.00
	Total Effluent	.00	492.56	492.56
*** TOTAL ACCOUNTABLE ***		728.35	728.33	728.33

δ - The delta indicates an infinitesimal increase in time. This notation is used since there is no refill delay modeled in the LOCA mass and energy release calculations

TABLE 6.4.1.1-6
DOUBLE-ENDED HOT LEG BREAK ENERGY BALANCE
SEABROOK STATION SPU

Time (Seconds)		.00	22.40	22.40+δ
		Energy (Million Btu)		
Initial Energy	In Reactor Coolant System, Accumulators, Steam Generators	855.60	855.60	855.60
Added Energy	Pumped Injection	.00	.00	.00
	Decay Heat	.00	7.95	7.95
	Heat From Secondary	.00	-.61	-.61
	Total Added	.00	7.34	7.34
*** TOTAL AVAILABLE ***		855.60	862.94	862.94
Distribution	Reactor Coolant	303.09	14.97	17.87
	Accumulator	19.75	15.72	12.82
	Core Stored	28.61	11.27	11.27
	Primary Metal	151.86	143.65	143.65
	Secondary Metal	58.62	58.00	58.00
	Steam Generator	293.67	289.72	289.72
	Total Contents	855.60	533.33	533.33
Effluent	Break Flow	.00	329.01	329.01
	Emergency Core Cooling Systems Spill	.00	.00	.00
	Total Effluent	.00	329.01	329.01
*** TOTAL ACCOUNTABLE ***		855.60	862.34	862.34

δ - The delta indicates an infinitesimal increase in time. This notation is used since there is no refill delay modeled in the LOCA mass and energy release calculations

TABLE 6.4.1.1-7
DOUBLE-ENDED PUMP SUCTION BREAK MINIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)
.00000	.0	.0	.0	.0
.00107	90470.0	50635.2	42914.6	23962.1
.102	42495.0	23806.4	22153.1	12358.2
.202	43268.2	24421.1	24821.0	13859.3
.302	44222.9	25214.1	25358.5	14173.1
.402	45210.9	26094.4	24782.1	13865.6
.502	45819.2	26787.7	23864.9	13362.0
.601	45718.5	27056.2	23154.5	12970.0
.701	44598.3	26680.7	22575.2	12648.3
.801	42975.3	25965.7	22097.9	12382.3
.901	41363.9	25224.2	21785.7	12209.9
1.00	39937.3	24565.0	21606.4	12111.3
1.10	38712.8	24015.7	21520.9	12064.7
1.20	37681.3	23575.1	21477.7	12041.1
1.30	36747.3	23189.8	21450.8	12026.2
1.40	35902.0	22851.5	21431.1	12015.0
1.50	35109.1	22537.8	21425.4	12011.6
1.60	34327.4	22232.4	21435.5	12017.2
1.70	33468.2	21875.5	21439.3	12019.5
1.80	32657.6	21551.0	21417.7	12007.5
1.90	31754.7	21163.7	21361.0	11975.7
2.00	30806.0	20740.8	21268.2	11923.9
2.10	29845.8	20301.7	21149.4	11858.0
2.20	28823.6	19810.9	20974.8	11760.8
2.30	27674.8	19217.4	20601.8	11551.5
2.40	26039.6	18259.1	20213.3	11335.1
2.50	23557.0	16657.4	19965.6	11198.4
2.60	21413.9	15276.6	19716.1	11060.5

NOTES 1. Mass and energy exiting the steam generator side of the break

2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-7 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MINIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)
2.70	20919.5	15055.6	19439.5	10907.5
2.80	19801.7	14324.4	19156.1	10751.0
2.90	18921.3	13758.0	18892.3	10606.1
3.00	18070.1	13195.6	18655.1	10476.5
3.10	17212.0	12617.5	18417.1	10346.5
3.20	16440.7	12098.4	18200.1	10228.7
3.30	15793.6	11663.4	18006.1	10124.0
3.40	15249.0	11295.7	17813.3	10020.0
3.50	14795.3	10987.9	17635.0	9924.2
3.60	14424.4	10735.6	17474.3	9838.5
3.70	14101.4	10513.2	17313.4	9752.7
3.80	13807.9	10308.9	17159.6	9670.7
3.90	13554.3	10131.1	17022.0	9598.1
4.00	13338.4	9976.5	16886.7	9526.6
4.20	12972.8	9704.7	16629.8	9391.2
4.40	12699.8	9489.6	16393.2	9267.1
4.60	12495.3	9315.8	16187.4	9160.3
4.80	12371.4	9195.0	16002.6	9065.2
5.00	12338.4	9135.1	15816.0	8968.4
5.20	12304.4	9073.2	16702.9	9483.9
5.40	12279.4	9019.2	16663.5	9470.1
5.60	12293.4	8992.9	16591.0	9437.2
5.80	12292.3	8962.3	16403.5	9337.6
6.00	12228.3	8899.4	16282.0	9275.7
6.20	12109.5	8808.6	16089.6	9172.1
6.40	11957.0	8703.2	15891.4	9064.5
6.60	11765.9	8579.6	15695.5	8956.3

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-7 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MINIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)
6.80	11611.7	8496.1	15497.5	8845.0
7.00	11637.1	8574.2	15452.9	8821.0
7.20	10890.6	8674.7	15428.7	8803.2
7.40	9286.2	8151.8	15065.6	8588.8
7.60	8850.7	7905.7	14826.4	8453.2
7.80	8829.5	7758.0	14692.1	8380.0
8.00	8935.0	7630.5	14504.6	8270.4
8.20	9153.5	7569.4	14249.1	8119.5
8.40	9420.3	7553.7	14093.7	8027.5
8.60	9670.7	7550.4	13925.6	7927.7
8.80	9869.6	7540.3	13724.4	7809.0
9.00	10008.5	7517.9	13570.9	7718.7
9.20	10067.1	7467.5	13404.9	7621.4
9.40	10025.5	7372.6	13236.3	7522.8
9.60	9915.0	7254.7	13090.5	7438.0
9.80	9750.6	7119.7	12940.2	7350.6
10.0	9548.7	6976.3	12795.4	7266.7
10.2	9339.9	6840.7	12658.5	7187.5
10.2	9338.8	6840.0	12657.7	7187.1
10.4	9124.2	6708.5	12517.3	7106.1
10.6	8915.8	6586.9	12380.7	7027.6
10.8	8713.2	6470.9	12242.8	6948.5
11.0	8517.4	6360.7	12105.0	6869.6
11.2	8326.4	6254.1	11969.1	6791.9
11.4	8141.6	6152.2	11832.5	6713.7
11.6	7961.3	6051.9	11697.5	6636.4
11.8	7769.4	5942.4	11530.9	6541.3

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-7 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MINIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)
12.0	7580.3	5831.2	11373.0	6452.3
12.2	7398.4	5714.2	11215.1	6363.5
12.4	7235.2	5598.8	11055.1	6272.5
12.6	7082.8	5482.5	10907.8	6188.4
12.8	6941.8	5375.0	10748.0	6097.1
13.0	6809.8	5268.1	10596.4	6011.1
13.2	6684.2	5156.6	10438.7	5921.6
13.4	6569.8	5051.5	10285.3	5834.8
13.6	6457.4	4947.2	10139.4	5752.4
13.8	6354.1	4850.9	10004.7	5676.2
14.0	6259.0	4761.3	9880.7	5605.6
14.2	6167.5	4676.9	9743.7	5527.5
14.4	6079.0	4600.3	9671.2	5489.4
14.6	5999.4	4533.9	9499.3	5390.0
14.8	5920.4	4473.3	9459.7	5371.1
15.0	5836.5	4410.2	9309.6	5287.9
15.2	5757.1	4355.0	9224.1	5243.8
15.4	5673.6	4302.3	9127.3	5195.0
15.6	5586.0	4252.4	9018.6	5140.8
15.8	5477.5	4192.8	8723.7	4979.1
16.0	5308.4	4100.6	8474.6	4849.4
16.2	5088.8	3982.0	8102.9	4642.1
16.4	4867.0	3862.8	7870.7	4494.4
16.6	4652.3	3741.6	7624.2	4305.9
16.8	4450.4	3614.3	7473.9	4140.0
17.0	4268.0	3488.7	7415.2	4003.9
17.2	4136.2	3391.7	7183.5	3788.0

NOTES 1. Mass and energy exiting the steam generator side of the break

2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-7 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MINIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)
17.4	4065.6	3331.5	6995.0	3627.5
17.6	3979.2	3313.8	6637.7	3384.0
17.8	3770.0	3290.3	6309.9	3158.4
18.0	3481.4	3249.9	6006.0	2962.8
18.2	3163.6	3195.2	5688.9	2770.9
18.4	2846.5	3121.4	5375.2	2586.5
18.6	2554.3	3004.5	5067.2	2410.9
18.8	2307.8	2819.9	4774.5	2247.9
19.0	2088.8	2580.1	4507.7	2103.0
19.2	1926.9	2391.0	4093.1	1881.3
19.4	1782.4	2218.5	3727.3	1639.4
19.6	1655.3	2065.3	3437.6	1438.4
19.8	1536.1	1920.4	3131.9	1253.7
20.0	1416.3	1773.9	3094.5	1191.7
20.2	1286.9	1614.9	3435.5	1284.6
20.4	1170.2	1471.0	3774.4	1384.9
20.6	1053.5	1326.9	3318.0	1202.2
20.8	953.0	1202.5	2633.6	948.9
21.0	862.3	1089.2	2438.5	875.5
21.2	777.9	983.7	2110.0	754.3
21.4	702.6	889.4	1866.8	664.3
21.6	633.9	803.1	1592.2	561.7
21.8	569.8	722.3	880.7	309.3
22.0	442.5	561.3	213.5	75.3
22.2	318.3	404.1	253.4	87.6
22.4	283.1	359.9	.0	.0
22.6	269.9	343.4	.0	.0

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-7 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MINIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)	FLOW (Lbm/sec)	ENERGY Thousand (Btu/sec)
22.8	260.5	331.6	.0	.0
23.0	230.2	293.0	.0	.0
23.2	186.9	238.1	.0	.0
23.4	136.3	173.9	.0	.0
23.6	95.8	122.4	.0	.0
23.8	53.4	68.4	.0	.0
24.0	.0	.0	.0	.0

NOTES 1. Mass and energy exiting the steam generator side of the break

2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-8
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
24.6	.0	.0	.0	.0
24.7	.0	.0	.0	.0
24.8	.0	.0	.0	.0
24.9	.0	.0	.0	.0
25.0	.0	.0	.0	.0
25.0	.0	.0	.0	.0
25.1	73.7	87.0	.0	.0
25.2	27.7	32.7	.0	.0
25.4	21.5	25.4	.0	.0
25.5	25.6	30.2	.0	.0
25.6	32.5	38.3	.0	.0
25.7	40.7	48.0	.0	.0
25.8	47.3	55.8	.0	.0
25.9	52.1	61.5	.0	.0
26.0	56.6	66.8	.0	.0
26.1	60.9	71.8	.0	.0
26.2	64.9	76.6	.0	.0
26.3	68.8	81.2	.0	.0
26.4	72.6	85.6	.0	.0
26.5	76.2	89.9	.0	.0
26.6	79.7	94.0	.0	.0
26.7	83.0	97.9	.0	.0
26.8	86.3	101.8	.0	.0
26.9	89.4	105.5	.0	.0
27.0	92.5	109.2	.0	.0
27.1	95.5	112.7	.0	.0
28.1	122.0	144.0	.0	.0
29.1	144.1	170.1	.0	.0
30.1	250.1	295.7	2126.9	291.6

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-8 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
30.6	437.5	518.7	4287.4	615.0
31.1	463.1	549.4	4496.3	671.7
32.1	460.0	545.7	4465.7	673.4
33.1	452.4	536.6	4396.4	666.4
34.1	444.5	527.1	4322.1	658.4
34.8	476.1	565.0	4651.6	680.4
35.1	473.7	562.1	4628.8	678.1
36.1	466.1	553.0	4558.0	669.9
37.1	458.6	544.1	4488.1	661.7
38.1	451.4	535.4	4419.5	653.7
39.1	444.4	527.1	4352.6	645.8
40.0	438.3	519.8	4293.8	638.9
40.1	437.7	519.0	4287.4	638.1
41.1	431.2	511.2	4224.0	630.6
42.1	424.9	503.8	4162.3	623.4
43.1	418.9	496.5	4102.5	616.3
44.1	413.0	489.6	4044.3	609.5
45.1	407.4	482.9	3987.7	602.8
46.0	402.5	477.0	3938.1	596.9
46.1	402.0	476.4	3932.7	596.3
47.1	396.7	470.1	3879.2	590.0
48.1	391.7	464.1	3827.2	583.9
49.1	386.8	458.2	3776.5	577.9
50.1	382.0	452.6	3727.2	572.0
51.1	323.3	382.8	2933.5	512.1
52.2	343.5	406.5	293.2	181.4
52.6	418.5	496.1	325.5	226.1
53.2	435.0	515.8	332.4	236.2
54.2	427.4	506.7	328.9	231.5

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-8 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
55.2	417.0	494.3	324.3	225.3
56.2	406.6	481.9	319.6	219.1
57.2	396.5	469.9	315.2	213.1
58.2	387.5	459.1	311.2	207.7
59.2	378.8	448.7	307.3	202.5
60.2	370.4	438.7	303.6	197.6
61.2	362.2	428.9	300.0	192.8
62.2	354.3	419.5	296.6	188.2
63.2	346.6	410.4	293.2	183.7
64.2	339.2	401.5	290.0	179.5
65.2	332.0	393.0	286.9	175.4
66.2	325.1	384.7	283.9	171.4
66.6	322.3	381.5	282.7	169.8
67.2	318.3	376.7	281.0	167.6
68.2	311.8	369.0	278.2	163.9
69.2	305.6	361.5	275.5	160.4
70.2	299.5	354.3	272.9	157.0
71.2	293.7	347.4	270.5	153.7
72.2	288.0	340.7	268.1	150.6
73.2	282.6	334.2	265.8	147.6
74.2	277.3	328.0	263.6	144.7
75.2	272.3	322.0	261.5	142.0
76.2	267.4	316.2	259.4	139.3
77.2	262.8	310.7	257.5	136.8
78.2	258.3	305.4	255.6	134.4
79.2	254.0	300.3	253.9	132.0
80.2	249.8	295.4	252.1	129.8
81.2	245.9	290.6	250.5	127.7
82.2	242.1	286.1	248.9	125.7

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-8 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
83.2	238.5	281.9	247.4	123.8
84.2	235.0	277.7	246.0	122.0
84.7	233.3	275.8	245.3	121.1
85.2	231.7	273.8	244.6	120.2
87.2	225.5	266.5	242.1	117.0
89.2	219.8	259.7	239.7	114.1
91.2	214.6	253.6	237.6	111.4
93.2	209.9	248.0	235.7	109.0
95.2	205.7	243.0	234.0	106.8
97.2	201.8	238.4	232.5	104.9
99.2	198.3	234.3	231.1	103.1
101.2	195.2	230.6	229.8	101.6
103.2	192.4	227.3	228.7	100.2
105.2	189.9	224.3	227.7	98.9
107.1	187.8	221.8	226.9	97.8
107.2	187.7	221.6	226.8	97.8
109.2	185.7	219.3	226.0	96.8
111.2	183.9	217.2	225.4	95.9
113.2	182.4	215.4	224.7	95.2
115.2	181.1	213.8	224.2	94.5
117.2	179.9	212.5	223.7	93.9
119.2	178.9	211.3	223.3	93.4
121.2	178.1	210.3	223.0	93.0
123.2	177.3	209.4	222.7	92.6
125.2	176.7	208.7	222.4	92.3
127.2	176.3	208.1	222.2	92.0
129.2	175.9	207.7	222.1	91.8
131.2	175.6	207.3	221.9	91.6
132.3	175.4	207.2	221.9	91.5

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-8 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
133.2	175.3	207.1	221.8	91.5
135.2	175.2	206.9	221.7	91.4
137.2	175.1	206.8	221.7	91.3
139.2	175.1	206.8	221.6	91.3
141.2	175.1	206.8	221.6	91.2
143.2	175.2	206.9	221.6	91.2
145.2	175.3	207.0	221.6	91.2
147.2	175.4	207.2	221.6	91.3
149.2	175.6	207.4	221.7	91.3
151.2	175.8	207.6	221.7	91.4
153.2	176.0	207.8	221.8	91.5
155.2	176.2	208.1	221.9	91.5
157.2	176.5	208.4	221.9	91.6
159.0	176.7	208.7	222.0	91.7
159.2	176.7	208.7	222.0	91.7
161.2	177.0	209.1	222.1	91.8
163.2	177.3	209.4	222.2	91.9
165.2	177.6	209.8	222.3	92.0
167.2	178.0	210.2	222.4	92.2
169.2	178.3	210.6	222.5	92.3
171.2	178.7	211.0	222.6	92.4
173.2	179.0	211.4	222.7	92.6
175.2	179.4	211.8	222.8	92.7
177.2	179.7	212.3	222.9	92.9
179.2	180.1	212.7	223.0	93.0
181.2	180.5	213.2	223.2	93.2
183.2	181.9	214.8	224.1	93.8
185.2	183.1	216.2	225.8	94.6
186.7	184.0	217.4	227.6	95.2

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-9
DOUBLE-ENDED PUMP SUCTION BREAK- MINIMUM SAFEGUARDS
PRINCIPLE PARAMETERS DURING REFLOOD
SEABROOK STATION SPU

Time	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accum	Spill	Enthalpy
Secs.	(°F)	(in/sec)	(-----)	(Feet)	(Feet)	(-----)	(Pounds Mass Per Second)			Btu/Lbm
24.0	172.4	.000	.000	.00	.00	.250	.0	.0	.0	.00
24.8	170.3	21.96	.000	.64	1.48	.000	7366.1	7366.1	.0	89.50
25.0	169.1	24.03	.000	1.02	1.39	.000	7318.9	7318.9	.0	89.50
25.4	168.4	2.681	.121	1.33	2.03	.257	7210.2	7210.2	.0	89.50
25.6	168.4	3.001	.162	1.37	2.63	.267	7165.7	7165.7	.0	89.50
26.3	168.4	2.708	.300	1.50	4.75	.331	7005.0	7005.0	.0	89.50
27.1	168.6	2.628	.408	1.61	7.16	.348	6843.4	6843.4	.0	89.50
30.6	169.4	4.655	.633	2.01	16.09	.594	5773.9	5773.9	.0	89.50
31.1	169.5	4.714	.651	2.08	16.12	.589	5597.7	5597.7	.0	89.50
32.1	169.8	4.515	.676	2.21	16.12	.588	5453.0	5453.0	.0	89.50
34.1	170.6	4.229	.703	2.43	16.12	.584	5217.4	5217.4	.0	89.50
34.8	170.9	4.384	.710	2.51	16.12	.598	5586.5	5035.4	.0	87.19
40.0	173.5	3.983	.733	3.01	16.12	.587	5115.1	4553.5	.0	86.92
46.0	177.1	3.693	.741	3.51	16.12	.575	4683.1	4111.8	.0	86.64
51.1	180.4	3.247	.745	3.90	16.12	.503	3559.5	2968.6	.0	85.61
52.2	181.0	3.381	.743	3.97	16.09	.576	591.8	.0	.0	66.04
52.6	181.3	3.762	.747	4.00	16.01	.591	568.5	.0	.0	66.04
53.2	181.7	3.838	.747	4.05	15.86	.594	562.0	.0	.0	66.04
59.2	186.9	3.391	.747	4.51	14.53	.585	575.7	.0	.0	66.04
66.6	194.2	2.956	.745	5.00	13.39	.572	588.3	.0	.0	66.04
75.2	203.4	2.576	.743	5.51	12.57	.556	598.2	.0	.0	66.04
84.7	213.7	2.282	.742	6.00	12.14	.539	604.5	.0	.0	66.04
97.2	225.2	2.043	.741	6.58	12.05	.521	608.3	.0	.0	66.04
107.1	232.9	1.934	.742	7.00	12.22	.512	609.9	.0	.0	66.04
121.2	242.2	1.854	.745	7.57	12.65	.505	610.9	.0	.0	66.04

TABLE 6.4.1.1-9 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK- MINIMUM SAFEGUARDS
PRINCIPLE PARAMETERS DURING REFLOOD
SEABROOK STATION SPU

Time	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accum	Spill	Enthalpy
Secs.	(°F)	(in/sec)	(----)	(Feet)	(Feet)	(----)	(Pounds Mass Per Second)			Btu/Lbm
132.3	248.5	1.826	.748	8.00	13.07	.503	611.2	.0	.0	66.04
147.2	256.0	1.814	.753	8.57	13.68	.503	611.3	.0	.0	66.04
155.2	259.6	1.812	.756	8.86	14.02	.504	611.2	.0	.0	66.04
159.0	261.3	1.813	.757	9.00	14.18	.504	611.2	.0	.0	66.04
173.2	266.9	1.816	.762	9.52	14.79	.506	611.0	.0	.0	66.04
186.7	271.6	1.837	.767	10.00	15.34	.511	610.5	.0	.0	66.04

TABLE 6.4.1.1-10
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
186.7	229.3	287.2	389.6	140.6
191.7	229.0	286.9	389.9	140.4
196.7	228.8	286.5	390.2	140.2
201.7	228.5	286.2	390.4	140.0
206.7	227.4	284.8	391.5	140.1
211.7	227.4	284.7	391.6	139.8
216.7	226.2	283.3	392.7	139.9
221.7	226.1	283.2	392.8	139.6
226.7	226.0	283.0	393.0	139.4
231.7	224.8	281.5	394.2	139.5
236.7	224.6	281.3	394.3	139.3
241.7	224.4	281.0	394.6	139.1
246.7	223.1	279.4	395.8	139.1
251.7	222.8	279.1	396.1	138.9
256.7	222.5	278.7	396.4	138.7
261.7	222.2	278.3	396.7	138.6
266.7	220.8	276.6	398.1	138.7
271.7	220.4	276.1	398.5	138.5
276.7	220.0	275.5	398.9	138.4
281.7	219.6	275.0	399.4	138.2
286.7	219.0	274.3	399.9	138.1
291.7	218.5	273.6	400.4	138.0
296.7	217.9	272.9	401.0	137.8
301.7	217.3	272.1	401.7	137.7
306.7	216.6	271.2	402.3	137.6
311.7	215.8	270.3	403.1	137.6
316.7	215.9	270.4	403.0	137.3
321.7	215.1	269.4	403.8	137.2

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-10 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
326.7	214.2	268.2	404.7	137.2
331.7	214.1	268.1	404.9	136.9
336.7	213.0	266.8	405.9	136.9
341.7	212.7	266.4	406.2	136.7
346.7	211.5	264.9	407.4	136.8
351.7	211.1	264.3	407.8	136.6
356.7	210.5	263.6	408.4	136.5
361.7	209.8	262.8	409.1	136.4
366.7	209.0	261.7	409.9	136.3
371.7	208.8	261.5	410.1	136.1
376.7	207.7	260.1	411.2	136.1
381.7	207.1	259.4	411.8	136.0
386.7	206.4	258.5	412.5	135.9
391.7	206.1	258.1	412.8	135.7
396.7	205.5	257.4	413.4	135.6
401.7	204.7	256.3	414.3	135.5
406.7	204.2	255.7	414.8	135.4
411.7	203.2	254.5	415.7	135.3
416.7	202.9	254.1	416.0	135.1
421.7	201.9	252.8	417.1	135.1
426.7	201.5	252.4	417.4	134.9
431.7	200.4	251.0	418.5	135.0
436.7	199.9	250.3	419.0	134.8
441.7	211.4	264.8	407.5	137.1
446.7	96.3	120.6	522.6	167.8
606.3	96.3	120.6	522.6	167.8
606.4	98.6	122.6	520.4	162.9
606.7	98.6	122.6	520.4	162.9

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-10 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	Break Path No. 1[1]		Break Path No. 2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
1278.0	98.6	122.6	520.4	162.9
1278.1	83.2	95.7	535.8	43.0
2940.0	67.9	78.2	551.0	45.8
2940.1	67.9	78.2	484.5	88.4
3600.0	63.8	73.4	488.7	89.1
3600.1	53.8	61.9	498.7	75.4
4773.0	49.0	56.3	503.5	76.1
4773.1	48.8	56.1	503.7	74.1
9783.0	39.2	45.1	513.2	75.5
9783.1	38.9	44.8	513.5	71.4
10000.0	38.6	44.4	513.8	71.5
19800.0	32.2	37.0	520.3	72.4
19800.1	31.9	36.7	503.1	65.5
39243.0	26.6	30.7	508.3	66.1
39243.1	26.5	30.4	508.5	62.6
77013.0	22.0	25.3	513.0	63.2
77013.1	21.9	25.1	513.1	60.6
100000.0	20.2	23.3	514.7	60.8
312974.0	14.2	16.4	520.7	61.5
312974.1	14.2	16.3	520.8	58.9
1000000.0	8.6	9.9	526.3	59.5
1000000.1	8.6	9.9	526.4	57.2
10000000.0	2.7	3.1	532.3	57.8

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-11
DOUBLE-ENDED PUMP SUCTION BREAK MASS BALANCE
MINIMUM SAFEGUARDS
SEABROOK STATION SPU

		Mass Balance						
Time (Seconds)		.00	24.00	24.00+δ	186.65	606.44	1277.99	3600.00
		Mass (Thousand lbm)						
Initial	In Reactor Coolant System and ACC	728.35	728.35	728.35	728.35	728.35	728.35	728.35
Added Mass	Pumped Injection	.00	.00	.00	91.49	351.28	766.91	2160.17
	Total Added	.00	.00	.00	91.49	351.28	766.91	2160.17
*** TOTAL AVAILABLE ***		728.35	728.35	728.35	819.84	1079.63	1495.26	2888.52
Distribution	Reactor Coolant	507.63	46.30	80.23	138.86	138.86	138.86	138.86
	Accumulator	220.72	174.10	140.16	.00	.00	.00	.00
	Total Contents	728.35	220.40	220.40	138.86	138.86	138.86	138.86
Effluent	Break Flow	.00	507.94	507.94	669.44	929.23	1344.86	2738.13
	Emergency Core Cooling Systems Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	507.94	507.94	669.44	929.23	1344.86	2738.13
*** TOTAL ACCOUNTABLE ***		728.35	728.33	728.33	808.30	1068.09	1483.72	2876.99

δ - The delta indicates an infinitesimal increase in time. This notation is used since there is no refill delay modeled in the LOCA mass and energy release calculations

TABLE 6.4.1.1-12
DOUBLE-ENDED PUMP SUCTION BREAK ENERGY BALANCE
MINIMUM SAFEGUARDS
SEABROOK STATION SPU

		Energy Balance						
Time (Seconds)		.00	24.00	24.00+δ	186.65	606.44	1277.99	3600.00
		Energy (Million Btu)						
Initial Energy	In Reactor Coolant System, ACC, S GEN	855.60	855.60	855.60	855.60	855.60	855.60	855.60
Added Energy	Pumped Injection	.00	.00	.00	6.04	23.20	50.65	173.69
	Decay Heat	.00	7.97	7.97	28.45	68.70	121.55	263.21
	Heat From Secondary	.00	.32	.32	.32	3.12	6.90	6.90
	Total Added	.00	8.29	8.29	34.81	95.02	179.09	443.80
*** TOTAL AVAILABLE ***		855.60	863.90	863.90	890.41	950.63	1034.70	1299.41
Distribution	Reactor Coolant	303.09	10.71	13.75	36.60	36.60	36.60	36.60
	Accumulator	19.75	15.58	12.54	.00	.00	.00	.00
	Core Stored	28.61	15.27	15.27	4.95	4.75	4.43	3.33
	Primary Metal	151.86	145.21	145.21	120.32	85.84	65.93	49.86
	Secondary Metal	58.62	58.94	58.94	54.03	42.29	30.05	22.78
	Steam Generator	293.67	295.73	295.73	266.72	204.48	144.77	110.51
	Total Contents	855.60	541.45	541.45	482.61	373.96	281.78	223.08
Effluent	Break Flow	.00	321.86	321.86	396.87	565.73	740.22	1067.06
	Emergency Core Cooling Systems Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	321.86	321.86	396.87	565.73	740.22	1067.06
*** TOTAL ACCOUNTABLE ***		855.60	863.31	863.31	879.48	939.69	1022.00	1290.14

δ - The delta indicates an infinitesimal increase in time. This notation is used since there is no refill delay modeled in the LOCA mass and energy release calculations

TABLE 6.4.1.1-13
DOUBLE-ENDED PUMP SUCTION BREAK MAXIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
.00000	.0	.0	.0	.0
.00107	90470.0	50635.2	42914.6	23962.1
.102	42495.0	23806.4	22153.1	12358.2
.202	43268.2	24421.1	24821.0	13859.3
.302	44222.9	25214.1	25358.5	14173.1
.402	45210.9	26094.4	24782.1	13865.6
.502	45819.2	26787.7	23864.9	13362.0
.601	45718.5	27056.2	23154.5	12970.0
.701	44598.3	26680.7	22575.2	12648.3
.801	42975.3	25965.7	22097.9	12382.3
.901	41363.9	25224.2	21785.7	12209.9
1.00	39937.3	24565.0	21606.4	12111.3
1.10	38712.8	24015.7	21520.9	12064.7
1.20	37681.3	23575.1	21477.7	12041.1
1.30	36747.3	23189.8	21450.8	12026.2
1.40	35902.0	22851.5	21431.1	12015.0
1.50	35109.1	22537.8	21425.4	12011.6
1.60	34327.4	22232.4	21435.5	12017.2
1.70	33468.2	21875.5	21439.3	12019.5
1.80	32657.6	21551.0	21417.7	12007.5
1.90	31754.7	21163.7	21361.0	11975.7
2.00	30806.0	20740.8	21268.2	11923.9
2.10	29845.8	20301.7	21149.4	11858.0
2.20	28823.6	19810.9	20974.8	11760.8
2.30	27674.8	19217.4	20601.8	11551.5
2.40	26039.6	18259.1	20213.3	11335.1
2.50	23557.0	16657.4	19965.6	11198.4
2.60	21413.9	15276.6	19716.1	11060.5
2.70	20919.5	15055.6	19439.5	10907.5
2.80	19801.7	14324.4	19156.1	10751.0
2.90	18921.3	13758.0	18892.3	10606.1
3.00	18070.1	13195.6	18655.1	10476.5
3.10	17212.0	12617.5	18417.1	10346.5
3.20	16440.7	12098.4	18200.1	10228.7

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-13 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MAXIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
3.30	15793.6	11663.4	18006.1	10124.0
3.40	15249.0	11295.7	17813.3	10020.0
3.50	14795.3	10987.9	17635.0	9924.2
3.60	14424.4	10735.6	17474.3	9838.5
3.70	14101.4	10513.2	17313.4	9752.7
3.80	13807.9	10308.9	17159.6	9670.7
3.90	13554.3	10131.1	17022.0	9598.1
4.00	13338.4	9976.5	16886.7	9526.6
4.20	12972.8	9704.7	16629.8	9391.2
4.40	12699.8	9489.6	16393.2	9267.1
4.60	12495.3	9315.8	16187.4	9160.3
4.80	12371.4	9195.0	16002.6	9065.2
5.00	12338.4	9135.1	15816.0	8968.4
5.20	12304.4	9073.2	16702.9	9483.9
5.40	12279.4	9019.2	16663.5	9470.1
5.60	12293.4	8992.9	16591.0	9437.2
5.80	12292.3	8962.3	16403.5	9337.6
6.00	12228.3	8899.4	16282.0	9275.7
6.20	12109.5	8808.6	16089.6	9172.1
6.40	11957.0	8703.2	15891.4	9064.5
6.60	11765.9	8579.6	15695.5	8956.3
6.80	11611.7	8496.1	15497.5	8845.0
7.00	11637.1	8574.2	15452.9	8821.0
7.20	10890.6	8674.7	15428.7	8803.2
7.40	9286.2	8151.8	15065.6	8588.8
7.60	8850.7	7905.7	14826.4	8453.2
7.80	8829.5	7758.0	14692.1	8380.0
8.00	8935.0	7630.5	14504.6	8270.4
8.20	9153.5	7569.4	14249.1	8119.5
8.40	9420.3	7553.7	14093.7	8027.5
8.60	9670.7	7550.4	13925.6	7927.7
8.80	9869.6	7540.3	13724.4	7809.0
9.00	10008.5	7517.9	13570.9	7718.7
9.20	10067.1	7467.5	13404.9	7621.4
9.40	10025.7	7372.9	13175.4	7486.1

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-13 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MAXIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
9.60	9914.8	7254.6	13486.2	7624.2
9.80	9726.1	7102.1	13104.2	7386.7
10.0	9517.9	6956.6	13055.0	7351.5
10.2	9330.7	6835.7	13006.8	7321.2
10.4	9082.5	6682.1	12720.7	7152.9
10.6	8893.2	6578.7	12728.6	7153.8
10.8	8681.3	6454.6	12481.8	7010.7
11.0	8482.8	6346.1	12417.7	6971.5
11.2	8297.4	6242.7	12224.4	6860.1
11.4	8106.2	6137.2	12127.7	6803.5
11.6	7924.8	6035.9	11941.3	6696.3
11.8	7726.9	5921.6	11797.9	6614.0
12.0	7540.2	5809.1	11604.5	6504.3
12.2	7361.3	5689.2	11466.1	6425.8
12.4	7207.0	5576.3	11281.6	6320.5
12.6	7054.7	5458.2	11138.3	6238.3
12.8	6917.7	5352.4	10961.0	6137.1
13.0	6786.0	5242.0	10809.6	6050.6
13.2	6663.9	5132.2	10642.9	5955.9
13.4	6550.3	5026.7	10487.2	5867.1
13.6	6441.2	4924.2	10341.0	5784.2
13.8	6341.7	4830.0	10200.4	5704.2
14.0	6250.7	4743.4	10078.4	5634.7
14.2	6154.0	4656.2	9903.9	5535.2
14.4	6078.1	4590.1	9876.9	5522.1
14.6	5992.9	4521.7	9686.8	5413.6
14.8	5914.5	4461.1	9629.7	5383.6
15.0	5832.7	4400.9	9512.1	5319.6
15.2	5751.3	4345.6	9391.7	5255.6
15.4	5666.2	4293.2	9298.8	5208.4
15.6	5578.6	4244.8	9193.4	5156.2
15.8	5461.2	4180.6	8906.6	5000.6
16.0	5280.8	4082.9	8647.8	4862.4
16.2	5055.6	3961.9	8245.5	4638.2
16.4	4835.7	3843.6	8045.3	4512.3

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-13 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK MAXIMUM EMERGENCY CORE COOLING SYSTEMS FLOWS BLOWDOWN MASS AND ENERGY RELEASES SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
16.6	4621.7	3721.2	7763.6	4308.3
16.8	4422.7	3593.6	7598.1	4140.2
17.0	4244.5	3470.0	7544.0	4013.1
17.2	4119.4	3377.0	7202.4	3747.3
17.4	4055.6	3324.5	7069.2	3614.9
17.6	3958.7	3309.9	6671.9	3356.0
17.8	3732.5	3282.7	6339.6	3130.3
18.0	3435.1	3239.1	6025.9	2929.9
18.2	3117.0	3181.3	5712.8	2740.6
18.4	2802.1	3105.2	5403.8	2559.2
18.6	2515.0	2980.0	5094.0	2383.1
18.8	2272.7	2783.7	4801.0	2219.8
19.0	2061.5	2548.5	4546.9	2079.5
19.2	1903.8	2363.3	4106.5	1841.6
19.4	1760.5	2191.8	3765.1	1618.8
19.6	1637.1	2043.1	3403.8	1400.2
19.8	1506.1	1883.4	3361.9	1326.7
20.0	1372.7	1719.9	3570.4	1365.3
20.2	1248.1	1567.0	3623.8	1358.9
20.4	1151.9	1448.7	2976.9	1099.3
20.6	1048.2	1320.8	2597.0	951.9
20.8	955.3	1205.4	2375.4	862.3
21.0	860.9	1087.5	2051.8	729.0
21.2	764.4	966.7	1912.9	654.6
21.4	669.4	847.3	2013.7	654.0
21.6	566.9	718.2	2324.6	718.7
21.8	467.6	593.0	2597.3	771.4
22.0	381.5	484.1	2210.7	640.1
22.2	307.6	390.7	1662.0	474.3
22.4	253.2	322.0	1136.2	321.5
22.6	233.0	296.4	647.6	182.4
22.8	201.6	256.7	244.4	68.8
23.0	185.2	235.9	.0	.0
23.2	142.2	181.3	.0	.0
23.4	75.2	96.1	.0	.0
23.6	.0	.0	.0	.0

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-14
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
24.1	.0	.0	.0	.0
24.3	.0	.0	.0	.0
24.4	.0	.0	.0	.0
24.5	.0	.0	.0	.0
24.6	.0	.0	.0	.0
24.6	.0	.0	.0	.0
24.7	71.0	83.7	.0	.0
24.8	27.0	31.9	.0	.0
25.0	22.3	26.2	.0	.0
25.1	26.7	31.5	.0	.0
25.2	34.4	40.6	.0	.0
25.3	41.8	49.3	.0	.0
25.4	48.4	57.1	.0	.0
25.5	53.1	62.7	.0	.0
25.6	57.7	68.0	.0	.0
25.7	61.9	73.0	.0	.0
25.8	66.0	77.8	.0	.0
25.9	69.9	82.4	.0	.0
26.0	73.6	86.9	.0	.0
26.1	77.2	91.1	.0	.0
26.2	80.7	95.2	.0	.0
26.3	84.1	99.2	.0	.0
26.4	87.4	103.1	.0	.0
26.5	90.5	106.8	.0	.0
26.6	93.6	110.5	.0	.0
26.7	96.6	114.0	.0	.0
27.7	123.2	145.4	.0	.0
28.7	145.4	171.6	.0	.0
29.7	302.9	358.3	2797.5	387.6
30.1	442.1	524.2	4332.8	619.4
30.7	468.8	556.2	4548.9	679.1
31.7	464.1	550.6	4505.2	678.0
32.7	456.3	541.2	4433.2	670.6
33.7	448.1	531.5	4356.9	662.3

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-14 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)	FLOW (LBM/SEC)	ENERGY THOUSAND (BTU/SEC)
34.3	443.2	525.6	4310.5	657.2
34.7	439.9	521.7	4279.7	653.8
35.7	432.0	512.2	4203.1	645.2
36.7	424.2	502.9	4128.0	636.7
37.7	416.7	494.0	4054.7	628.4
38.7	409.5	485.4	3983.3	620.3
39.7	402.6	477.1	3914.0	612.3
39.8	401.9	476.3	3907.2	611.6
40.7	443.4	525.9	4349.6	640.7
41.7	437.1	518.3	4287.9	633.5
42.7	431.0	511.0	4228.1	626.4
43.7	425.1	504.0	4169.9	619.6
44.7	419.4	497.2	4113.4	612.9
45.6	414.5	491.3	4063.8	607.1
45.7	414.0	490.7	4058.4	606.4
46.7	408.7	484.4	4004.9	600.1
47.7	403.6	478.3	3952.9	594.0
48.7	398.6	472.4	3902.2	588.0
49.7	393.8	466.6	3852.9	582.2
50.7	389.2	461.1	3804.8	576.5
51.7	322.9	382.2	3086.7	500.2
52.2	351.4	415.9	330.2	181.1
52.8	375.1	444.4	339.8	194.5
53.8	372.6	441.4	338.6	193.1
54.8	366.9	434.6	336.2	189.8
55.8	361.4	427.9	333.8	186.7
56.8	356.0	421.5	331.5	183.7
57.8	350.7	415.3	329.3	180.7
58.8	345.7	409.3	327.2	177.9
59.8	340.8	403.4	325.1	175.2
60.8	336.0	397.7	323.1	172.5
61.8	331.3	392.1	321.1	169.9
62.8	326.3	386.3	319.1	167.2
63.8	322.2	381.3	317.4	165.0

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-14 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
64.8	318.3	376.7	315.8	162.9
65.8	314.5	372.2	314.2	160.8
66.8	310.9	367.9	312.7	158.8
67.8	307.4	363.7	311.3	156.9
68.8	304.0	359.6	309.9	155.1
69.8	300.7	355.7	308.5	153.3
70.8	297.5	351.9	307.2	151.6
71.8	294.4	348.2	306.0	150.0
72.8	291.4	344.7	304.8	148.4
73.8	288.5	341.3	303.6	146.9
74.8	285.7	338.0	302.5	145.4
75.8	283.1	334.8	301.4	144.0
76.8	280.5	331.7	300.4	142.7
77.8	278.0	328.8	299.4	141.4
78.8	275.6	325.9	298.4	140.1
79.8	273.3	323.2	297.5	138.9
80.8	271.1	320.6	296.6	137.8
81.8	269.0	318.0	295.8	136.7
82.8	266.9	315.6	295.0	135.6
83.8	264.9	313.2	294.2	134.6
83.9	264.7	313.0	294.1	134.5
84.8	263.0	311.0	293.5	133.6
86.8	259.5	306.8	292.1	131.8
88.8	256.2	302.9	290.8	130.2
90.8	253.2	299.4	289.6	128.7
92.8	250.5	296.2	288.6	127.3
94.8	248.1	293.3	287.6	126.1
96.8	245.9	290.6	286.7	125.0
98.8	243.9	288.3	286.0	124.0
100.8	242.1	286.1	285.3	123.1
102.8	240.5	284.2	284.6	122.2
103.3	240.1	283.8	284.5	122.0
104.8	239.0	282.5	284.1	121.5
106.8	237.7	281.0	283.5	120.9

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-14 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
108.8	237.6	280.8	283.8	120.8
110.8	237.5	280.7	284.8	120.8
112.8	237.6	280.8	286.6	121.1
114.8	238.0	281.2	289.3	121.6
116.8	238.5	281.9	292.7	122.2
118.8	239.1	282.6	296.6	122.9
120.8	239.6	283.2	300.9	123.7
122.8	240.1	283.8	305.4	124.5
124.0	240.4	284.1	308.3	125.0
124.8	240.5	284.3	310.2	125.3
126.8	240.7	284.5	315.2	126.1
128.8	240.7	284.5	320.3	126.9
130.8	240.6	284.3	325.6	127.6
132.8	240.2	283.9	330.9	128.2
134.8	239.6	283.3	336.4	128.8
136.8	238.9	282.3	341.9	129.4
138.8	237.9	281.2	347.6	130.0
140.8	236.7	279.7	353.3	130.5
142.8	235.2	278.0	359.1	131.0
144.8	233.6	276.0	365.0	131.4
146.0	232.5	274.7	368.5	131.7
146.8	231.7	273.8	370.9	131.8
148.8	229.6	271.3	376.9	132.2
150.8	227.2	268.5	383.0	132.6
152.8	224.7	265.5	389.2	132.9
154.8	221.9	262.2	395.4	133.3
156.8	218.8	258.6	401.7	133.6
158.8	215.6	254.8	408.2	133.9
160.8	212.2	250.7	414.7	134.3
162.8	208.6	246.4	421.3	134.6
164.8	204.8	241.9	428.0	135.0
166.8	200.8	237.2	434.9	135.5
168.8	196.6	232.2	442.0	135.9
170.6	192.6	227.5	448.4	136.4

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-15
DOUBLE-ENDED PUMP SUCTION BREAK- MAXIMUM SAFEGUARDS
PRINCIPLE PARAMETERS DURING REFLOOD
SEABROOK STATION SPU

Time (sec)	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Frac	Total	Injection Accum	Spill	Enthalpy Btu/lbm
	Temp °F	Rate in/sec					(Pounds Mass per Second)			
23.6	170.1	.000	.000	.00	.00	.250	.0	.0	.0	.00
24.4	168.0	22.159	.000	.64	1.50	.000	7450.0	7450.0	.0	89.50
24.6	166.9	24.275	.000	1.03	1.41	.000	7401.5	7401.5	.0	89.50
25.0	166.3	2.735	.124	1.34	2.08	.258	7289.6	7289.6	.0	89.50
25.2	166.3	3.014	.165	1.38	2.69	.274	7243.8	7243.8	.0	89.50
25.9	166.3	2.717	.303	1.50	4.83	.331	7078.6	7078.6	.0	89.50
26.7	166.4	2.640	.411	1.62	7.27	.349	6912.7	6912.7	.0	89.50
30.1	167.3	4.697	.632	2.01	16.09	.596	5836.9	5836.9	.0	89.50
30.7	167.5	4.737	.654	2.09	16.12	.591	5638.4	5638.4	.0	89.50
31.7	167.9	4.532	.678	2.22	16.12	.589	5495.8	5495.8	.0	89.50
34.3	169.0	4.183	.709	2.51	16.12	.584	5190.7	5190.7	.0	89.50
39.8	171.9	3.772	.732	3.01	16.12	.569	4670.8	4670.8	.0	89.50
40.7	172.4	4.000	.735	3.09	16.12	.590	5175.0	4450.0	.0	86.21
45.6	175.6	3.767	.741	3.50	16.12	.580	4828.0	4095.6	.0	85.94
51.7	179.7	3.203	.743	3.97	16.12	.531	3699.7	2945.5	.0	84.72
52.2	180.0	3.379	.745	4.00	16.10	.557	749.6	.0	.0	66.04
52.8	180.4	3.497	.746	4.05	16.03	.564	742.1	.0	.0	66.04
59.8	186.4	3.216	.747	4.54	15.31	.555	749.1	.0	.0	66.04
66.8	193.7	2.983	.747	5.00	14.87	.546	755.0	.0	.0	66.04

TABLE 6.4.1.1-15 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK- MAXIMUM SAFEGUARDS
PRINCIPLE PARAMETERS DURING REFLOOD
SEABROOK STATION SPU

Time (sec)	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Frac	Total	Injection Accum	Spill	Enthalpy Btu/lbm
	Temp °F	Rate in/sec					(Pounds Mass per Second)			
75.8	203.9	2.765	.748	5.54	14.60	.535	760.2	.0	.0	66.04
83.9	213.5	2.620	.750	6.00	14.56	.527	763.4	.0	.0	66.04
94.8	225.0	2.486	.752	6.58	14.73	.519	766.0	.0	.0	66.04
103.3	232.8	2.418	.755	7.00	14.99	.515	767.1	.0	.0	66.04
114.8	241.9	2.384	.759	7.56	15.42	.515	767.4	.0	.0	66.04
124.0	248.4	2.376	.762	8.00	15.72	.520	767.0	.0	.0	66.04
134.8	255.1	2.339	.765	8.50	15.94	.524	766.9	.0	.0	66.04
146.0	261.2	2.260	.768	9.00	16.06	.524	767.7	.0	.0	66.04
158.8	267.1	2.119	.770	9.54	16.11	.517	769.8	.0	.0	66.04
170.6	271.6	1.950	.771	10.00	16.12	.501	772.7	.0	.0	66.04

TABLE 6.4.1.1-16
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
170.61	178.0	222.2	603.8	168.8
175.6	176.1	219.8	605.7	169.0
180.6	174.3	217.4	607.5	169.2
185.6	173.4	216.3	608.4	169.2
190.6	171.5	214.0	610.3	169.4
195.6	170.7	212.9	611.2	169.3
200.6	168.8	210.7	613.0	169.5
205.6	167.3	208.7	614.5	169.7
210.6	165.7	206.8	616.1	169.8
215.6	164.2	204.9	617.6	169.9
220.6	162.7	203.0	619.1	170.1
225.6	161.2	201.1	620.7	170.2
230.6	159.7	199.2	622.2	170.3
235.6	158.2	197.3	623.7	170.5
240.6	156.7	195.5	625.1	170.6
245.6	155.2	193.6	626.6	170.7
250.6	153.7	191.8	628.1	170.8
255.6	151.3	188.8	630.5	171.2
260.6	149.9	187.0	632.0	171.3
265.6	148.4	185.2	633.4	171.4
270.6	147.0	183.4	634.8	171.5
275.6	144.6	180.4	637.2	171.8
280.6	143.2	178.7	638.6	171.9
285.6	143.7	179.3	638.1	171.5
290.6	143.2	178.7	638.6	171.3
295.6	143.7	179.3	638.1	170.9
300.6	143.2	178.7	638.6	170.7
305.6	142.7	178.1	639.1	170.6
310.6	143.2	178.7	638.6	170.2
315.6	142.7	178.1	639.1	170.0
320.6	143.1	178.6	638.7	169.6
325.6	142.7	178.0	639.2	169.4
330.6	143.1	178.5	638.7	169.0

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-16 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
335.6	142.6	177.9	639.2	168.9
340.6	142.1	177.3	639.7	168.7
345.6	142.5	177.8	639.3	168.3
350.6	142.0	177.2	639.8	168.1
355.6	142.4	177.6	639.4	167.7
360.6	141.9	177.0	639.9	167.5
365.6	142.2	177.5	639.6	167.1
370.6	141.7	176.8	640.1	167.0
375.6	142.1	177.3	639.7	166.6
380.6	141.6	176.6	640.3	166.4
385.6	141.9	177.0	639.9	166.0
390.6	141.4	176.4	640.5	165.9
395.6	141.7	176.8	640.1	165.5
400.6	141.2	176.1	640.7	165.3
405.6	141.6	176.7	640.2	164.9
410.6	141.2	176.2	640.6	164.7
415.6	140.8	175.7	641.0	164.5
420.6	141.3	176.3	640.6	164.1
425.6	140.8	175.7	641.0	163.9
430.6	141.3	176.3	640.5	163.5
435.6	140.8	175.7	641.0	163.3
440.6	141.2	176.2	640.6	162.8
445.6	140.8	175.7	641.0	168.2
450.6	140.4	175.1	641.4	168.0
455.6	140.7	175.6	641.1	167.5
460.6	140.3	175.1	641.5	167.3
465.6	140.7	175.5	641.2	166.9
470.6	140.2	174.9	641.6	166.7
475.6	140.5	175.3	641.3	166.3
480.6	140.1	174.8	641.8	166.0
485.6	140.4	175.1	641.4	165.6
490.6	139.9	174.5	641.9	165.4

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-16 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
495.6	140.2	174.9	641.6	165.0
500.6	140.4	175.2	641.4	164.6
505.6	139.9	174.6	641.9	164.4
510.6	140.2	174.9	641.7	164.0
515.6	139.6	174.2	642.2	163.8
520.6	139.8	174.5	642.0	163.4
525.6	140.0	174.7	641.8	163.0
530.6	139.5	174.0	642.3	162.8
535.6	139.6	174.2	642.2	162.4
540.6	139.8	174.4	642.0	162.0
545.6	139.9	174.6	641.9	161.6
550.6	139.3	173.8	642.5	161.4
555.6	139.4	173.9	642.4	161.0
560.6	139.5	174.0	642.3	160.6
565.6	139.5	174.1	642.3	160.3
570.6	139.5	174.1	642.3	159.9
575.6	139.5	174.1	642.3	159.5
580.6	139.5	174.1	642.3	159.2
585.6	138.8	173.1	643.0	164.2
590.6	139.4	173.9	642.5	163.7
595.6	139.2	173.7	642.6	163.3
600.6	139.1	173.5	642.7	163.0
605.6	139.0	173.4	642.8	162.6
610.6	138.8	173.2	643.0	162.2
615.6	138.6	172.9	643.2	161.9
620.6	139.0	173.4	642.8	161.4
625.6	138.7	173.1	643.1	161.1
630.6	138.4	172.6	643.4	160.8
635.6	138.6	172.9	643.2	160.3
640.6	138.7	173.1	643.1	159.9
645.6	138.8	173.1	643.1	159.5
650.6	138.2	172.4	643.6	159.2

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-16 (continued)
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
POST-REFLOOD MASS AND ENERGY RELEASES
SEABROOK STATION SPU

	BREAK PATH NO.1[1]		BREAK PATH NO.2[2]	
TIME (sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)	FLOW (lbm/sec)	ENERGY THOUSAND (BTU/sec)
655.6	138.6	172.9	643.2	158.7
660.6	138.4	172.7	643.4	158.4
665.6	138.1	172.3	643.8	158.0
670.6	138.1	172.3	643.7	157.6
675.6	138.0	172.2	643.8	162.2
680.6	138.2	172.4	643.6	161.7
685.6	88.0	109.8	693.8	174.8
1038.4	88.0	109.8	693.8	174.8
1038.5	89.5	110.7	692.3	165.0
1040.6	89.4	110.7	692.4	164.5
1233.8	89.4	110.7	692.4	164.5
1233.9	85.3	98.1	696.5	53.1
1560.0	80.3	92.4	701.5	54.0
1560.1	80.3	92.4	825.7	165.7
3600.0	65.2	75.0	840.8	168.4
3600.1	55.4	63.7	850.6	153.4
10000.0	40.3	46.3	865.7	156.1
18900.0	34.0	39.1	872.0	157.2
18900.1	34.0	39.1	912.5	164.5
100000.0	21.5	24.8	925.0	166.8
1000000.0	9.2	10.6	937.3	169.0
10000000.0	2.9	3.3	943.6	170.1

NOTES
1. Mass and energy exiting the steam generator side of the break
2. Mass and energy exiting the pump side of the break

TABLE 6.4.1.1-17
DOUBLE-ENDED PUMP SUCTION BREAK MASS BALANCE
MAXIMUM SAFEGUARDS
SEABROOK STATION SPU

		Mass Balance						
Time (Seconds)		.00	23.60	23.60+δ	170.58	1038.47	1233.85	3600.00
		Mass (Thousand lbm)						
Initial	In Reactor Coolant System and Accumulators	728.35	728.35	728.35	728.35	728.35	728.35	728.35
Added Mass	Pumped Injection	.00	.00	.00	99.39	777.90	930.65	3033.90
	Total Added	.00	.00	.00	99.39	777.90	930.65	3033.90
*** TOTAL AVAILABLE ***		728.35	728.35	728.35	827.74	1506.25	1659.00	3762.25
Distribution	Reactor Coolant	507.63	44.58	79.16	139.11	139.11	139.11	139.11
	Accumulator	220.72	177.38	142.80	.00	.00	.00	.00
	Total Contents	728.35	221.96	221.96	139.11	139.11	139.11	139.11
Effluent	Break Flow	.00	510.55	510.55	681.26	1359.76	1512.51	3615.76
	Emergency Core Cooling Systems Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	510.55	510.55	681.26	1359.76	1512.51	3615.76
*** TOTAL ACCOUNTABLE ***		728.35	732.51	732.51	820.37	1498.87	1651.62	3754.87

δ - The delta indicates an infinitesimal increase in time. This notation is used since there is no refill delay modeled in the LOCA mass and energy release calculations

TABLE 6.4.1.1-18
DOUBLE-ENDED PUMP SUCTION BREAK ENERGY BALANCE
MAXIMUM SAFEGUARDS
SEABROOK STATION SPU

		Energy Balance						
Time (Seconds)		.00	23.60	23.60+δ	170.58	1038.47	1233.85	3600.00
		Energy (Million Btu)						
Initial Energy	In Reactor Coolant System, Accumulators, Steam Generators	855.60	855.60	855.60	855.60	855.60	855.60	855.60
Added Energy	Pumped Injection	.00	.00	.00	6.56	51.37	61.46	411.50
	Decay Heat	.00	7.90	7.90	26.66	103.71	118.33	263.09
	Heat From Secondary	.00	.33	.33	.33	6.12	6.72	6.72
	Total Added	.00	8.22	8.22	33.56	161.20	186.50	681.31
*** TOTAL AVAILABLE ***		855.60	863.83	863.83	889.16	1016.81	1042.11	1536.92
Distribution	Reactor Coolant	303.09	10.40	13.50	36.90	36.90	36.90	36.90
	Accumulator	19.75	15.87	12.78	.00	.00	.00	.00
	Core Stored	28.61	15.20	15.20	4.95	4.75	4.64	3.33
	Primary Metal	151.86	145.25	145.25	119.79	73.74	67.69	50.11
	Secondary Metal	58.62	58.95	58.95	53.50	34.24	30.55	22.94
	Steam Generator	293.67	295.78	295.78	263.72	164.03	146.82	111.02
	Total Contents	855.60	541.46	541.46	478.86	313.66	286.62	224.31
Effluent	Break Flow	.00	322.06	322.06	399.65	692.50	732.14	1292.20
	Emergency Core Cooling Systems Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	322.06	322.06	399.65	692.50	732.14	1292.20
*** TOTAL ACCOUNTABLE ***		855.60	863.52	863.52	878.51	1006.16	1018.76	1516.51

δ - The delta indicates an infinitesimal increase in time. This notation is used since there is no refill delay modeled in the LOCA mass and energy release calculations

TABLE 6.4.1.1-19
DOUBLE-ENDED HOT LEG BREAK
SEQUENCE OF EVENTS
SEABROOK STATION SPU

Time (sec)	Event Description
0.0	Break Occurs, Reactor Trip and Loss of Offsite Power are assumed
4.3	Low Pressurizer Pressure Safety Injection Setpoint - 1664.7 psia reached in blowdown
14.6	Broken Loop Accumulator Begins Injecting Water
14.7	Intact Loop Accumulator Begins Injecting Water
22.4	End of Blowdown Phase

TABLE 6.4.1.1-20
DOUBLE-ENDED PUMP SUCTION BREAK
MINIMUM SAFEGUARDS
SEQUENCE OF EVENTS
SEABROOK STATION SPU

Time (sec)	Event Description
0.0	Break Occurs, Reactor Trip and Loss of Offsite Power are assumed
4.3	Low Pressurizer Pressure Safety Injection Setpoint - 1664.7 psia reached in blowdown
16.1	Broken Loop Accumulator Begins Injecting Water
16.3	Intact Loop Accumulator Begins Injecting Water
24.0	End of Blowdown Phase
34.3	Safety Injection Begins
51.001	Broken Loop Accumulator Water Injection Ends
51.901	Intact Loop Accumulator Water Injection Ends
186.651	End of Reflood Phase
2940.0	Cold Leg Recirculation Begins
19800.	Hot Leg Recirculation Begins
1.0E+07	Transient Modeling Terminated

TABLE 6.4.1.1-21
DOUBLE-ENDED PUMP SUCTION BREAK
MAXIMUM SAFEGUARDS
SEQUENCE OF EVENTS
SEABROOK STATION SPU

Time (sec)	Event Description
0.0	Break Occurs, Reactor Trip and Loss of Offsite Power are assumed
4.3	Low Pressurizer Pressure Safety Injection Setpoint - 1664.7 psia reached in blowdown
9.3	Safety Injection Begins
16.1	Broken Loop Accumulator Begins Injecting Water
16.3	Intact Loop Accumulator Begins Injecting Water
23.6	End of Blowdown Phase
50.926	Broken Loop Accumulator Water Injection Ends
51.826	Intact Loop Accumulator Water Injection Ends
170.706	End of Reflood Phase
1560.	Cold Leg Recirculation Begins
19800.	Hot Leg Recirculation Begins
1.0E+07	Transient Modeling Terminated

TABLE 6.4.1.1-22
LOCA MASS AND ENERGY RELEASE ANALYSIS
CORE DECAY HEAT FRACTION

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
1.00E+01	0.053876
1.50E+01	0.050401
2.00E+01	0.048018
4.00E+01	0.042401
6.00E+01	0.039244
8.00E+01	0.037065
1.00E+02	0.035466
1.50E+02	0.032724
2.00E+02	0.030936
4.00E+02	0.027078
6.00E+02	0.024931
8.00E+02	0.023389
1.00E+03	0.022156
1.50E+03	0.019921
2.00E+03	0.018315
4.00E+03	0.014781
6.00E+03	0.013040
8.00E+03	0.012000
1.00E+04	0.011262
1.50E+04	0.010097
2.00E+04	0.009350
4.00E+04	0.007778
6.00E+04	0.006958
8.00E+04	0.006424
1.00E+05	0.006021
1.50E+05	0.005323
4.00E+05	0.003770
6.00E+05	0.003201
8.00E+05	0.002834
1.00E+06	0.002580

TABLE 6.4.4.1-1

NOMINAL AND INITIAL ANALYSIS ASSUMPTIONS FOR SPU[1] MSLB M&E RELEASES INSIDE CONTAINMENT

Plant Parameter	Nominal	Full Power Initial
NSSS power, MWt	3678	3678
Core power, MWt	3659	3658
Reactor coolant pump heat, MWt	19	20
Reactor coolant flow (total), gpm (thermal design flow)	374,400	374,400
Pressurizer pressure, psia	2250	2250
Pressurizer water volume (% span)	60.0	60.0
Reactor coolant vessel average temperature, °F	589.1	595.1
Steam generator[2]		
Steam temperature, °F	542.7	550.8
Steam pressure, psia	985	1052
Feedwater temperature, °F	452.4	452.4
Water level, % narrow-range span	50.0	>58.0 (58.5)
Zero-load temperature, °F	557	557

Notes:

(1) Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the Reactor Coolant System T_{avg} window, initial temperature includes applicable calorimetric uncertainties and bias.

(2) Steam generator performance data used in the analysis is conservatively high for steam temperature and pressure.

TABLE 6.4.4.1-2
PART-POWER INITIAL-CONDITION ANALYSIS ASSUMPTIONS FOR SPU[1] MSLB M&E RELEASES INSIDE CONTAINMENT

Initial Conditions	Power Level (%)		
Parameter	**70**	**30**	**2**
Reactor Coolant System average temperature (°F)	585.5	572.7	560.0
Reactor Coolant System flowrate (gpm) (thermal design flow)	374,400	374,400	374,400
Reactor Coolant System pressure (psia)	2249	2251	2251
Pressurizer water volume (% span)	47.2	33.3	28.0
Feedwater enthalpy (Btu/lbm)	390.24	305.15	70.59
Steam generator pressure (psia)[2]	1077	1112	1109
Steam generator water level (% narrow range span)	>58.0 (58.5)	>58.0 (58.5)	>58.0 (58.5)

Notes:

(1) Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the Reactor Coolant System T_{avg} window, temperatures includes applicable calorimetric uncertainties and/or bias.

(2) The noted steam generator pressures are determined at the steady-state conditions defined by the Reactor Coolant System average temperatures, including applicable uncertainties and/or bias.

TABLE 6.4.4.1-3
MAIN AND EMERGENCY FEEDWATER SYSTEM ASSUMPTIONS FOR SPU MAIN STEAMLINE BREAK MASS AND ENERGY RELEASES INSIDE CONTAINMENT

Parameter	Analysis Assumption
Main Feedwater System	
Flowrate (until main feedwater isolation)	
Double-ended ruptures, lbm/sec	2900
Split breaks	Feedwater flow equals steam flow.
Non-isolable volume from steam generator nozzle to main feedwater isolation valve (faulted loop), ft^3	160.5
Non-isolable volume from steam generator nozzle to feedwater control valve assuming a single failure of the main feedwater isolation valve (faulted loop), ft^3	558.0
Emergency Feedwater System	
Flowrate to all steam generators	Maximum flow to the steam generator in the faulted loop; no flow to each of the other 3 steam generators.
Double-ended ruptures, gpm	750
Split breaks, gpm	525
Temperature (maximum value), °F	100
Piping purge volume, ft^3	15.0
Actuation delay time, seconds	0

TABLE 6.4.4.1-4
PROTECTION SYSTEM ACTUATION SIGNALS AND SAFETY SYSTEM SETPOINTS FOR SPU MAIN STEAMLINE BREAK MASS AND ENERGY RELEASES INSIDE CONTAINMENT

Actuation Signal	Safety Analysis Setpoint
Reactor Trip	
2/4 Low pressurizer pressure, psia	1935
Safety Injection	Yes
Safety Injection	
2/4 Low pressurizer pressure, psia	1665
2/3 Low steamline pressure in any loop, psia	430
Dynamic compensation lead, seconds	50
Dynamic compensation lag, seconds	5
2/3 High-1 Containment Pressure	implicit
Steamline Isolation	
2/3 Low steamline pressure in any loop, psia	430
Dynamic compensation lead, seconds	50
Dynamic compensation lag, seconds	5
2/3 High-2 Containment pressure	implicit
Feedwater Isolation and Emergency Feedwater Initiation	
Safety Injection	Yes

TABLE 6.4.4.1-5
TRANSIENT SUMMARY FOR THE SPECTRUM OF STEAMLINE BREAKS INSIDE CONTAINMENT

Initial Power, Single Failure	Break Type	Reactor Trip Signal	Rod Motion (sec)	Emergency Feedwater Initiation/ Termination (sec)	Main Feedwater Isolation, Faulted Steam Generator (sec)	Steamline Isolation (sec) (1) (2)	Faulted Steam Generator Dryout (sec)
100%, none	DER	SI-LSP	2.034	0.034 / 100.0	11.034	6.034	227
100%, MSIV	DER	SI-LSP	2.034	0.034 / 100.0	11.034	6.034	227
100%, MFIV	DER	SI-LSP	2.034	0.034 / 100.0	11.034	6.034	258
100%, none	split	High-1	15.5	13.5 / 1800	24.5	21.0	1900
100%, MSIV	split	High-1	15.5	13.5 / 1800	24.5	21.0	1875
100%, MFIV	split	High-1	15.5	13.5 / 1800	24.5	21.0	1900
70%, none	DER	SI-LSP	2.035	0.035 / 100.0	11.035	6.035	256
70%, MSIV	DER	SI-LSP	2.035	0.035 / 100.0	11.035	6.035	248
70%, MFIV	DER	SI-LSP	2.035	0.035 / 100.0	11.035	6.035	295
70%, none	split	High-1	15.0	13.0 / 1800	24.0	21.0	1900
70%, MSIV	split	High-1	15.0	13.0 / 1800	24.0	21.0	1900
70%, MFIV	split	High-1	15.0	13.0 / 1800	24.0	21.0	1900
30%, none	DER	SI-LSP	2.040	0.040 / 100.0	11.040	6.040	288
30%, MSIV	DER	SI-LSP	2.040	0.040 / 100.0	11.040	6.040	295
30%, MFIV	DER	SI-LSP	2.040	0.040 / 100.0	11.040	6.040	376
30%, none	split	High-1	15.0	13.0 / 1800	24.0	21.0	1900
30%, MSIV	split	High-1	15.0	13.0 / 1800	24.0	21.0	1900
30%, MFIV	split	High-1	15.0	13.0 / 1800	24.0	21.0	1900
0%, none	DER	SI-LSP	2.026	0.026 / 100.0	11.026	6.026	272
0%, MSIV	DER	SI-LSP	2.026	0.026 / 100.0	11.026	6.026	264
0%, MFIV	DER	SI-LSP	2.026	0.026 / 100.0	11.026	6.026	264
0%, none	split	High-1	16.0	14.0 / 1800	25.0	22.0	1865
0%, MSIV	split	High-1	16.0	14.0 / 1800	25.0	22.0	1885
0%, MFIV	split	High-1	16.0	14.0 / 1800	25.0	22.0	1865

Key SI – safety injection
LSP – low steam pressure
High-1 – containment high pressure

(1) For the MSIV-failure cases, steamline isolation occurs only in the 3 unfaulted steamlines; there is no closure of the MSIV in the faulted steamline.

(2) For the split breaks, the signal for steamline isolation is High-2 – containment pressure.

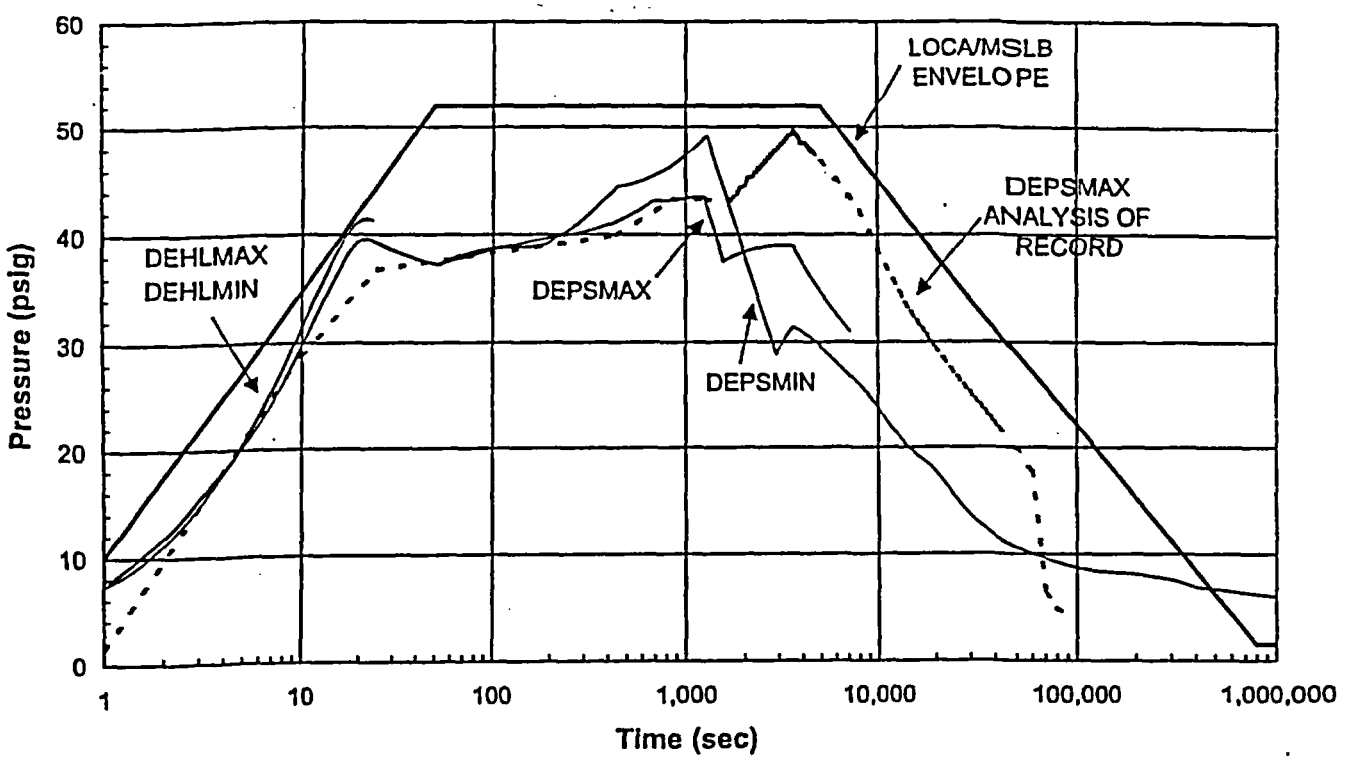


FIGURE 6.4.3-1
LOCA CONTAINMENT PRESSURE vs TIME
SPU CONDITIONS

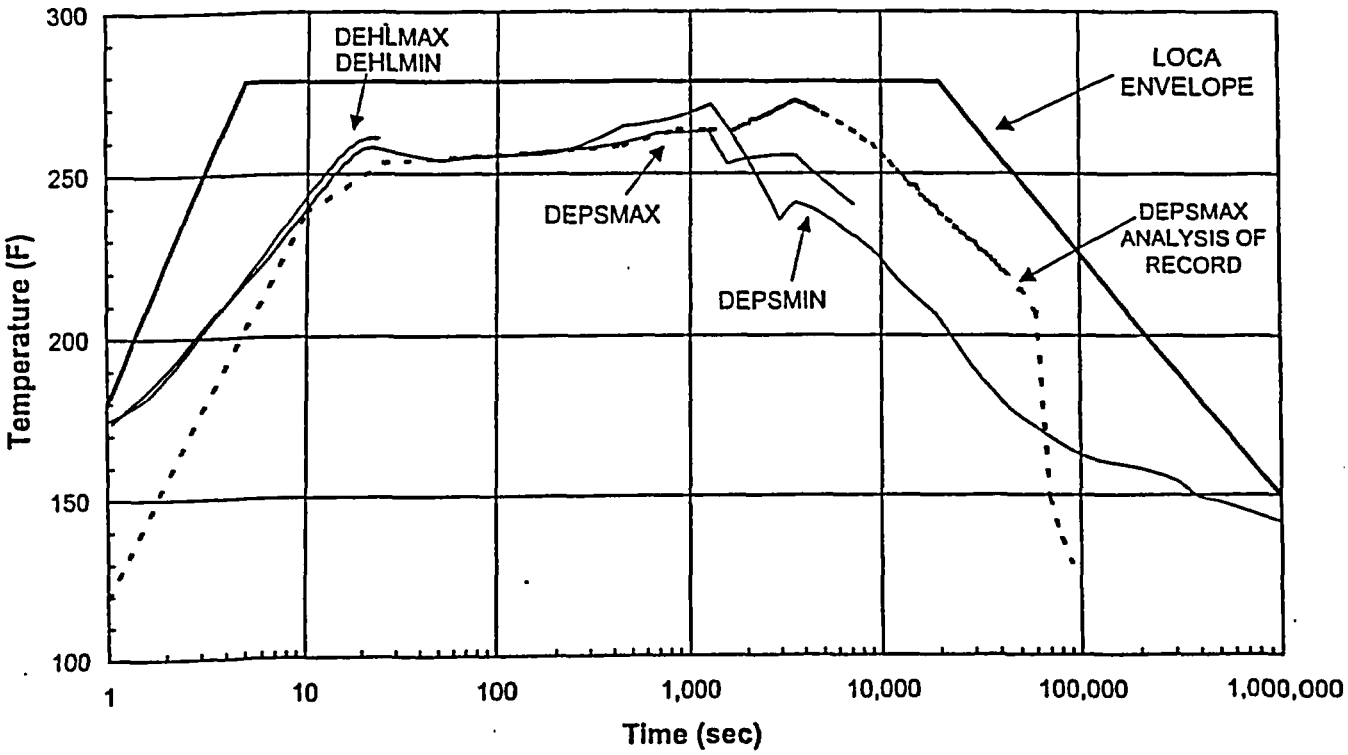


FIGURE 6.4.3-2
LOCA CONTAINMENT TEMPERATURE vs TIME
SPU CONDITIONS

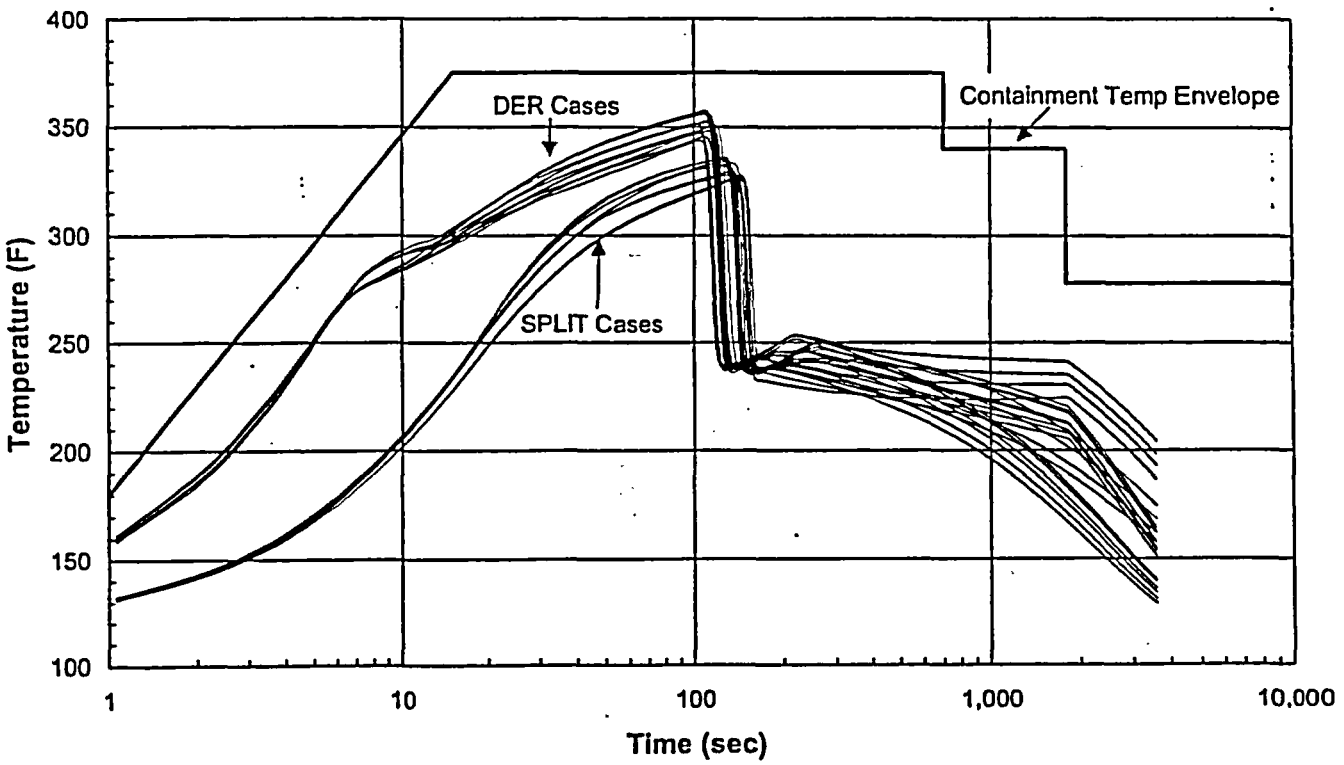


FIGURE 6.4.5-1
MAIN STEAMLINE BREAK TEMPERATURE vs TIME
SPU CONDITIONS

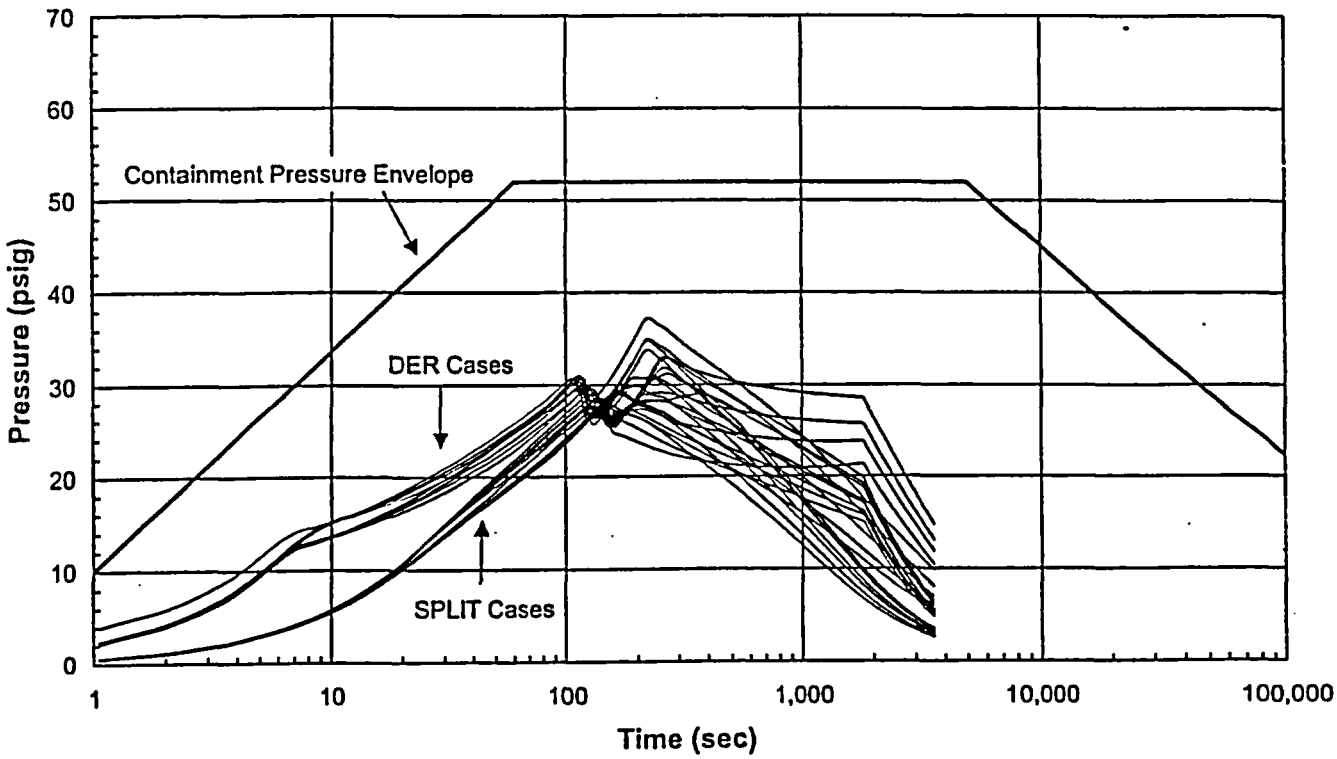


FIGURE 6.4.5-2
MAIN STEAMLINE BREAK TEMPERATURE vs TIME
SPU CONDITIONS

6.5 STEAMLINE BREAK OUTSIDE CONTAINMENT

6.5.1 DESCRIPTION

The Seabrook Station East and West Pipe Chase pressure and temperature response following a Main Steam Line Break outside containment is described in Seabrook Station UFSAR Appendix 3I Section 3.3. The SPU evaluation for a Main Steam Line Break in the East and West Pipe Chase demonstrated that the environments for the adjacent area rooms housing safety-related equipment are bounded by the existing analysis.

6.5.2 MASS AND ENERGY RELEASES OUTSIDE CONTAINMENT

6.5.2.1 INTRODUCTION

Steamline ruptures occurring outside the reactor containment structure may result in significant releases of high-energy fluid to the structures surrounding the steam systems. Superheated steam blowdowns following the steamline break have the potential to raise compartment temperatures outside containment. Early uncovery of the steam generator tube bundle maximizes the enthalpy of the superheated steam releases out the break. The impact of the steam releases depends on the plant configuration at the time of the break, the plant response to the break, as well as the size and location of the break. Because of the interrelationship among many of the factors that influence steamline break mass and energy releases, an appropriate determination of a single limiting case with respect to mass and energy releases cannot be made. Therefore, it is necessary to analyze the steamline break event outside containment for a range of conditions.

6.5.2.2 INPUT PARAMETERS AND ASSUMPTIONS

The analysis inputs, assumptions, and methods pertaining to the main steamline break mass and energy releases outside containment are presented in this section.

To determine the effects of plant power level and break area on the mass and energy releases from a ruptured steamline, spectra of both variables have been evaluated with respect to the timing of protection functions and the time to achieve steam generator tube uncovery, which maximizes the superheated release duration. A break spectrum initiated from 100% and 70% (of maximum analyzed power) has been analyzed at the conditions associated with the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The emphasis on maximizing the value of the superheated steam enthalpy due to early steam generator tube uncovery is consistent with the methodology developed in response to Reference 6.4-9. Other assumptions regarding important plant conditions and features are discussed in the following paragraphs.

Initial Power Level

The initial power that is assumed for steamline break analyses outside containment affects the mass and energy releases and steam generator tube bundle uncovery in two ways. First, the steam generator water mass inventory increases with decreasing power levels; this will tend to delay uncovery of the steam generator tube bundle, although the increased steam pressure associated with lower power levels will cause a faster blowdown at the beginning of the transient. Second, the amount of stored energy and decay heat, as well as feedwater temperature, are less for lower power levels; this will result in lower primary temperatures and less primary-to-secondary heat transfer during the steamline break event.

The initial power is the maximum analyzed NSSS power (3678 MWt), 100% of the SPU NSSS, as well as 70% of this power level. Overall, steamline breaks initiated from lower power levels result in lower levels of steam superheating than breaks analyzed at full-power conditions. The 70%-power initial condition is a representative power level that confirms this assumption for Seabrook Station. For this SPU analysis, the power level and steamline break sizes are noted in LAR Subsection 6.5.2.3.

In general, the plant initial conditions are assumed to be at the nominal value, with appropriate uncertainties included. LAR Table 6.5.2-1 identifies the values assumed for NSSS power, Reactor Coolant System pressure, Reactor Coolant System vessel average temperature, Reactor Coolant System flow, pressurizer water volume, steam generator water level, steam generator temperature and pressure, and feedwater enthalpy. Steamline break mass releases and superheated steam enthalpies assuming an Reactor Coolant System average temperature at the high end of the T_{avg} window are conservative. At the high end, there is a larger value for the superheated steam enthalpy available for release outside containment. The thermal design flowrate has been used for the Reactor Coolant System flow input consistent with the assumptions documented in Reference 6.4-10. The thermal design flowrate is also consistent with other main steamline break analysis assumptions related to nonstatistical treatment of uncertainties, as well as Reactor Coolant System thermal-hydraulic inputs related to pressure drops and rod drop time.

Uncertainties on the initial conditions assumed in the analysis for the power uprate program have been applied only to the Reactor Coolant System average temperature (6.0°F) and the steam generator mass (14.5% narrow-range span). The calorimetric uncertainty associated with power has been included in the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Nominal values are adequate for the initial conditions associated with pressurizer pressure and pressurizer water level. Uncertainty conditions are only applied to those parameters that could increase the enthalpy of superheated steam discharged out of the break.

Single-Failure Assumption

The main steamlines outside containment up to the first pipe whip restraint conform to Branch Technical Position MEB 3-1; therefore, a rupture in these pipes is not postulated. The main steamlines comprise part of the "no break zone" and a break postulated here is assumed to be the single failure. Therefore, no additional single-failure assumption has been made in the plant-specific analysis of the steamline break outside containment for Seabrook Station.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture results in large amounts of water being added to the steam generators through the main feedwater system. To maximize the superheated steam releases, main feedwater flow is conservatively modeled by assuming no increase in feedwater flow in response to the increases in steam flow following the steamline break event. This minimizes the total mass addition and associated cooling effects in the steam generators and causes the earliest onset of superheated steam released out of the break.

Isolation of the main feedwater flow is conservatively assumed to be initiated coincident with the reactor trip signal. Closing of the feedwater valves in the main feedwater lines is assumed to be instantaneous.

Steamline break mass and energy releases assuming a main feedwater temperature at the high end of the feedwater temperature window are conservative. At the high end, there is more energy available for release outside containment.

Emergency Feedwater System

Generally, within the first few minutes following a steamline break, the Emergency Feedwater System is initiated on any one of several protection system signals. Addition of emergency feedwater to the steam generators will increase the secondary mass available to cover the tube bundle and reduces the amount of superheated steam produced. For this reason, Emergency Feedwater flow is minimized while actuation delays are maximized to accentuate the depletion of the initial secondary-side inventory.

Steam Generator Fluid Mass

A minimum initial steam generator mass in all the steam generators has been used in the steamline break cases. The use of a reduced initial steam generator mass minimizes the availability of the heat sink afforded by the steam generators and leads to earlier tube bundle uncovery. The initial mass has been calculated as the value corresponding to the programmed level minus 14.5% narrow-range span. This level uncertainty accounts for the effects of the mid-deck plate differential pressure on the steam generator level instrumentation. The steam generator fluid masses are calculated assuming 0% tube plugging. This assumption is conservative with respect to the Reactor Coolant System cooldown through the steam generators resulting from the steamline break.

Steam Generator Reverse Heat Transfer

Once the steamline isolation is complete, the steam generators in the intact loops become sources of energy that can be transferred to the steam generator with the broken steamline. This energy transfer occurs via the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes could drop below the temperature of the secondary fluid in the intact steam generators, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. When applicable, the effects of reverse steam generator heat transfer are included in the results.

Break Flow Model

Piping discharge resistances are not included in the calculation of the releases resulting from the steamline ruptures (Moody Curve for an f (ℓ / D) = 0 is used). This maximizes the break flowrate and increases the energy release into the compartment, resulting in a maximum temperature for the assumed break area.

Steamline Volume Blowdown

There is no contribution to the mass and energy releases from the steam in the secondary plant main steam loop piping and header because the initial volume is saturated steam. The blowdown of the steam in this volume serves to delay the time of tube uncovery in the steam generators and is conservatively ignored.

Main Steamline Isolation

Steamline isolation is assumed for the steamline break cases since the break location is upstream of the main steamline isolation valves. A delay time of 6 seconds, accounting for delays associated with signal processing plus main steam isolation valve stroke time, with unrestricted steam flow through the valve during the valve stroke, has been assumed.

Protection System Actuations

The protection systems available to mitigate the effects of a main steamline break outside containment include reactor trip, safety injection, and emergency feedwater. The setpoints used are conservative values with respect to the plant-specific values delineated in the Technical Specifications. The specific functions credited in the Seabrook Station plant-specific analysis are documented in LAR Subsection 6.5.2.5.

Safety Injection System

Minimum Safety Injection System flowrates corresponding to the failure of one Safety Injection System train have been assumed in this analysis. A minimum Safety Injection flow is conservative since the reduced boron addition maximizes a return to power resulting from the Reactor Coolant System cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. A conservative delay time to achieve full Safety Injection flow is assumed for this analysis with offsite power available. A coincident loss of offsite

power is not assumed for the analysis of the steamline break outside containment since the mass and energy releases would be reduced due to the loss of forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

Reactor Coolant System Metal Heat Capacity

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, the reactor coolant pumps, and the steam generator thick-metal mass and tubing. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. The effects of this Reactor Coolant System metal heat are included in the results using conservative thick-metal masses and heat transfer coefficients.

Core Decay Heat

Core decay heat generation assumed in calculating the steamline break mass and energy releases is based on the 1979 American Nuclear Society Decay Heat + 2σ model [Reference 6.4-5].

Rod Control

The rod control system is conservatively assumed to be in manual operation for the steamline break analyses. If the reactor was in automatic rod control, the rods would withdraw to maintain nominal average temperature prior to reactor trip. Assuming that the reactor is in manual rod control allows for a greater Reactor Coolant System cooldown prior to the reactor trip signal, which maximizes the reactivity feedback at end-of-cycle conditions and produces a greater post-trip power increase.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle conditions are used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reactivity feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

6.5.2.3 DESCRIPTION OF ANALYSES AND EVALUATIONS

The system transient that provides the break flows and enthalpies of the steam release through the steamline break outside containment has been analyzed with the LOFTRAN [Reference 6.4-11] computer code. Blowdown mass and energy releases determined using LOFTRAN include the effects of core power generation, main and emergency feedwater additions, engineered safeguards systems, reactor coolant system thick-metal heat storage including steam generator thick-metal mass and tubing, and reverse steam generator heat transfer. The use of the LOFTRAN code for the analysis of the main steamline break with superheated steam mass and energy releases is documented in Supplement 1 of WCAP-8822 [Reference 6.4-10], which has been reviewed and approved by the NRC for use in analyzing main steamline breaks.

The Seabrook Station NSSS has been analyzed to determine the transient mass releases and associated superheated steam enthalpy values outside containment following a steamline break event. The tables of mass flowrates and steam enthalpies are used as input conditions to the environmental evaluation of safety-related electrical equipment in the main steam and feedwater pipe chases.

The following cases of the main steamline break outside containment have been analyzed at the noted conditions for the large power uprate program.

- At 100% power, break sizes of 1.0, 0.9, 0.8, 0.7, 0.6, 0.5, 0.4, 0.3, 0.2, and 0.1 ft^2
- At 70% power, break sizes of 1.0, 0.9, 0.8, 0.7, 0.6, 0.5, 0.4, 0.3, 0.2, and 0.1 ft^2

Each main steamline break outside containment is represented as a non-mechanistic split rupture. The largest break is postulated as a longitudinal break area of 1.0 ft^2, in accordance with Branch Technical Position ASB 3-1, paragraph B1.a.(1). Prior to steamline isolation, the steam flow is supplied by all four steam generators through the postulated break area represented by the spectrum noted above. After steamline isolation, the steam release through the break is supplied by a single steam generator.

6.5.2.4 ACCEPTANCE CRITERIA

The main steamline break is classified as an American Nuclear Society Condition IV event. The acceptance criteria associated with the steamline break event resulting in a mass and energy release outside containment are based on assumptions that maximize the superheated stream releases resulting from tube uncovery. The assumptions used in this steamline break mass and energy release analysis are discussed in LAR Subsection 6.5.2.2. The tables of mass flowrates and steam enthalpy values for each of the steamline break cases are used as input to the environmental evaluation of safety-related electrical equipment in the main steam and feedwater pipe chases outside containment.

6.5.2.5 RESULTS

Using the Seabrook Station plant-specific parameter changes associated with the SPU, the mass and energy release rates for each of the steamline break cases noted in LAR Subsection 6.5.2.3 have been developed for use in the environmental evaluation of safety-related electrical equipment in the main steam and feedwater pipe chases outside containment. LAR Table 6.5.2-2 provides the sequence of events for each of the 20 steamline break sizes initiated from a full-power or 70%-power condition at the SPU NSSS power.

For the large- and intermediate-sized breaks from 1.0 ft^2 to 0.6 ft^2 at full power, reactor trip is actuated following the Overpower ΔT (2-of-4 channels) signal. Main feedwater flow is assumed to be isolated coincident with the reactor trip signal. Safety injection is started as a result of a Low Pressurizer Pressure (2-of-4 channels) signal; steamline isolation occurs later due to receipt of the Low Steam Pressure signal (2-of-3 channels per loop). Emergency Feedwater initiation occurs as a result

of the Low-Low Steam Generator Water Level (2-of-4 channels per loop) signal. The Emergency Feedwater flow continues until 1800 seconds at which time it is isolated to the faulted-loop steam generator. Dryout of the steam generator occurs shortly after the Emergency Feedwater flow is discontinued.

For the smallest break sizes from 0.5 ft^2 to 0.1 ft^2 at full power, and the entire break spectrum at 70% power, the first protection signal received is the Low-Low Steam Generator Water Level signal, which actuates reactor trip and the Emergency Feedwater System. Main feedwater flow is assumed to be isolated coincident with the reactor trip signal. Safety injection occurs following a Low Pressurizer Pressure signal. Steamline isolation occurs later due to receipt of the Low Steam Pressure signal, except for the 0.1-ft^2 break. For this small break area, an automatic steamline isolation signal is not received since the steam generator depressurization does not actuate the Low Steam Pressure setpoint within 1800 seconds. Operator action at 30 minutes following event initiation is assumed to isolate the main steamlines for this break size. The Emergency Feedwater flow continues until 1800 seconds at which time it is isolated to the faulted-loop steam generator. Dryout of the steam generator occurs later in time after the Emergency Feedwater flow is discontinued.

Steamline break mass flowrate and steam enthalpy data, accounting for early steam generator tube uncovery and superheated steam releases, are presented in LAR Tables 6.5.2-3 through 6.5.2-22.

6.5.2.6 CONCLUSIONS

The mass releases and associated steam enthalpy values from the spectrum of steamline break cases outside containment have been analyzed at the SPU NSSS power conditions. The assumptions delineated in LAR Subsection 6.5.2.2 have been included in the steamline break analysis such that conservative mass and energy releases are calculated. The mass releases and associated steam enthalpy values discussed in this section have been provided for use in the environmental evaluation of safety-related electrical equipment in the main steam and feedwater pipe chases outside containment for Seabrook Station.

6.5.3 EVALUATION

The environmental conditions that result due to a postulated Main Steam Line Break in the Seabrook East and West Pipe Chase were developed using the GOTHIC computer code. GOTHIC models were developed for the East and West Pipe Chases and adjacent area rooms based upon the existing calculations of record analyzed using the COMPRESS code. Mass and energy release data for main steam line breaks outside containment were supplied by Westinghouse for an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). This data was input to the GOTHIC models to calculate the transient environmental temperatures and pressures for the Pipe Chase and adjacent area rooms. LAR Subsection 6.5.2 above provides a description of the mass and energy release data.

The GOTHIC model for the pipe chases and adjacent areas utilized the same volumes, heat sinks, initial and boundary conditions and flow areas as the existing calculation of record. The environmental conditions in the East and West Pipe Chase and adjacent areas were calculated based on a postulated full power, 0.1ft^2 Main Steam Line Break. The evaluation using mass and energy release data under SPU conditions resulted in an increase in the maximum temperature for the East and West Pipe Chase from 325°F to 468°F.

The Seabrook Station UFSAR Section 3.11 states that as a result of a detailed review of the main steam and feed water pipe chase design that Seabrook Station can achieve a safe shutdown under any postulated superheated temperature profile due to a Main Steam Line Break. This is achieved principally by the separation criteria conceptually designed into these building areas. Seabrook has two separated Main Steam/Feedwater pipe chase areas exiting the east and west sides of the containment. Each pipe chase houses main steam and feedwater piping for two of the four steam generators. The piping is designed under the concept of "superpipe" (i.e., low stress allowables and upgraded Inservice Inspection Program). The main steam and feed water pipe chase also houses the main steam and feedwater containment isolation valves, safety relief valves, atmospheric dump valves and the main steam supply valves to the emergency feed pump turbine. Since the Westinghouse requirement is for a minimum two-steam generator cool down, Seabrook can safely shutdown under a postulated main steam line break in the main steam and feed water pipe chase designed with "superpipe," using the opposite side pipe chase. Based on these design criteria Seabrook can achieve a safe shutdown under the postulated SPU mass and energy release due to a main steam line break without taking credit for the pipe chase where the break occurs.

Since the increase in main steam and feedwater pipe chase maximum temperature does not invalidate the above qualification licensing basis, this evaluation is limited to the environmental impact on adjacent areas.

The SPU evaluation concludes that the environmental conditions for the stairwell adjacent to the West Pipe Chase, and the Electrical Room and the Hydrogen Analyzer Room adjacent to the East Stairwell were bounded by the existing analysis. The East Stairwell has no safety-related equipment installed and is therefore not affected by the SPU.

The response of the outside containment structures to the SPU elevated peak temperature is addressed in LAR Subsection 8.6.3.

6.5.4 CONCLUSION

The effects of SPU on the East and West main steam pipe chases outside containment have been evaluated. The results from the analysis, using the Westinghouse mass and energy releases for a break in the main steam pipe chases under SPU conditions indicate an increase in the Main Steam and Feedwater Pipe Chase temperature from 325 to 468 F. This increase in temperature does not impact the existing qualification licensing basis for the Main Steam and Feedwater Pipe

Chases. Furthermore, the evaluation shows that in adjacent rooms housing safety-related equipment, that the resulting environmental temperatures are bounded by existing analysis of record.

TABLE 6.5.2-1
NOMINAL AND INITIAL ANALYSIS ASSUMPTIONS FOR THE SPU[1]
MAIN STEAMLINE BREAK M&E RELEASES OUTSIDE CONTAINMENT

Plant Parameter	Nominal	Analysis Assumptions	
		100%	70%
NSSS power, MWt	3678	3678	2574.6
Core power, MWt	3659	not an input	
Reactor coolant pump heat, MWt	18.4	19	
Reactor coolant flow (total), gpm (thermal design flow)	374,400	374,400	
Pressurizer pressure, psia	2250	2250	
Reactor coolant vessel average temperature, °F	589.1	595.1	585.47
Steam generator[2]			
Steam temperature, °F	542.7	548.9	552.7
Steam pressure, psia	985	1036	1068
Feedwater temperature, °F	452.4	452.4	413.27
Water level, % narrow-range span	50.0	35.5	
Zero-load temperature, °F	557	557	

Notes:

(1) Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the Reactor Coolant System T_{avg} window.

(2) Steam generator performance data used in the analysis is conservatively high for steam temperature and pressure.

TABLE 6.5.2-2
TRANSIENT SUMMARY FOR THE SPECTRUM OF FULL-POWER STEAMLINE BREAKS OUTSIDE CONTAINMENT

Power (% nom)	Break Size (ft^2)	Reactor Trip Signal	Rod Motion (sec)	Safety Injection Signal	Safety Injection (sec)	Feedwater Isolation (sec)	Steamline Isolation (sec)	Emergency Feedwater (sec)	SG Tube Uncovery (sec)
100	1.0	OPΔT	21.1	LPP	93.2	21.1	190.5	124.7	137.0
100	0.9	OPΔT	22.6	LPP	101.5	22.6	210.0	127.0	148.8
100	0.8	OPΔT	24.6	LPP	112.3	24.6	234.6	129.8	163.6
100	0.7	OPΔT	27.7	LPP	127.0	27.7	265.3	133.1	181.6
100	0.6	OPΔT	34.2	LPP	149.9	34.2	307.6	139.3	206.6
100	0.5	LSGWL	48.9	LPP	187.9	48.9	364.5	146.9	236.8
100	0.4	LSGWL	59.8	LPP	236.1	59.8	455.4	157.8	285.8
100	0.3	LSGWL	77.9	LPP	321.7	77.9	607.8	175.9	368.4
100	0.2	LSGWL	113.9	LPP	531.7	113.9	938.5	211.9	511.6
100	0.1	LSGWL	221.5	LPP	1427.	221.5	1800. (M)	319.5	858.0
70	1.0	LSGWL	22.9	LPP	100.2	22.9	222.4	120.9	162.4
70	0.9	LSGWL	25.1	LPP	109.8	25.1	245.3	123.1	176.6
70	0.8	LSGWL	27.8	LPP	122.0	27.8	273.5	125.8	194.0
70	0.7	LSGWL	31.3	LPP	138.2	31.3	310.9	129.3	217.4
70	0.6	LSGWL	35.9	LPP	159.9	35.9	360.6	133.9	247.6
70	0.5	LSGWL	42.4	LPP	190.3	42.4	431.4	140.4	288.4
70	0.4	LSGWL	52.0	LPP	237.2	52.0	540.2	150.0	349.0
70	0.3	LSGWL	67.9	LPP	318.5	67.9	727.3	165.9	451.6
70	0.2	LSGWL	99.5	LPP	492.9	99.5	1150.	197.5	671.0
70	0.1	LSGWL	193.7	LPP	1183.	193.7	1800. (M)	291.7	864.8

Key OPΔT - overpower ΔT
LPP - low pressurizer pressure
LSGWL - low-low steam generator water level
M - manual

TABLE 6.5.2-3
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 1.0 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	218.60	24.25	1302.48
.20	2066.02	1190.44	218.80	24.11	1302.52
2.80	1969.36	1192.11	219.00	21.38	1302.80
5.40	1897.44	1193.36	219.20	21.67	1302.81
10.60	1795.91	1195.03	219.40	19.24	1303.08
15.80	1737.18	1195.94	219.60	19.34	1303.09
21.00	1707.83	1196.39	219.80	17.25	1303.34
21.20	1792.29	1196.12	220.00	17.07	1303.38
22.80	1935.74	1193.89	220.20	16.19	1303.46
24.80	2084.73	1191.26	220.40	15.13	1303.60
26.80	2193.13	1189.31	220.80	15.13	1303.65
28.60	2224.01	1188.77	223.60	14.97	1303.85
39.40	2048.84	1192.06	223.80	14.12	1303.95
61.80	1744.43	1197.10	224.00	14.59	1303.90
72.80	1623.60	1198.82	224.40	14.94	1303.88
83.80	1528.84	1200.07	225.00	15.20	1303.90
94.80	1469.92	1200.79	225.60	15.25	1303.97
105.80	1445.71	1201.07	227.00	14.94	1304.18
148.40	1438.18	1202.74	229.80	13.64	1304.63
158.60	1418.55	1208.59	231.20	13.48	1304.74
169.00	1376.16	1214.88	303.40	13.52	1310.00
179.40	1307.79	1222.26	391.40	13.52	1315.00
190.80	1186.26	1235.80	505.20	13.51	1321.00
191.00	1147.60	1237.39	596.20	13.51	1325.00
192.40	973.43	1246.70	697.60	13.51	1328.67
193.60	850.87	1253.51	699.00	15.10	1328.45
195.00	729.20	1260.58	699.20	14.54	1328.50
196.40	623.56	1266.86	699.40	15.01	1328.42
198.00	519.99	1273.27	700.20	15.92	1328.29
199.40	413.94	1278.47	701.00	16.45	1328.25
200.20	364.78	1280.88	701.80	16.76	1328.24
201.40	302.44	1283.99	703.80	17.02	1328.30
202.00	274.79	1285.41	710.40	16.23	1328.52
202.60	250.14	1286.70	1000.00	16.28	1332.00
203.20	228.34	1287.89	1200.00	16.28	1335.00
203.80	209.12	1288.97	1400.00	16.28	1336.00
205.20	169.60	1291.18	1600.00	16.28	1338.00
206.40	141.93	1292.93	1800.00	16.28	1339.18
207.20	126.75	1293.95	1800.60	16.43	1339.17
209.20	95.36	1296.15	1801.00	16.01	1339.26
210.40	81.64	1297.11	1801.20	15.62	1339.32
211.60	69.21	1298.09	1801.40	15.06	1339.42
212.40	62.74	1298.64	1801.60	14.13	1339.57
213.00	58.46	1299.03	1801.80	.00	.00
214.40	49.44	1299.90	1900.00	.00	.00
215.60	42.48	1300.61			

TABLE 6.5.2-4
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.9 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	241.00	24.32	1302.56
.20	1864.08	1190.43	242.20	19.24	1303.20
3.00	1780.19	1192.04	242.60	16.92	1303.50
5.80	1718.25	1193.24	243.00	16.41	1303.60
11.40	1632.71	1194.81	243.40	15.23	1303.73
16.80	1586.76	1195.61	243.80	13.72	1303.95
22.40	1563.77	1196.00	244.00	12.32	1304.15
22.60	1636.72	1195.72	247.00	13.52	1304.17
24.20	1768.51	1193.41	247.20	13.17	1304.22
26.20	1906.79	1190.67	247.40	13.59	1304.17
28.00	2000.76	1188.76	247.80	14.08	1304.13
30.00	2040.04	1187.99	248.20	14.42	1304.11
38.80	1920.54	1190.54	249.20	14.89	1304.16
65.80	1613.87	1196.39	250.40	15.05	1304.28
77.80	1501.85	1198.22	252.60	14.73	1304.55
89.60	1412.49	1199.56	257.00	13.47	1304.96
101.60	1351.79	1200.41	259.20	13.30	1305.12
113.60	1325.21	1200.77	268.00	13.54	1305.68
161.60	1318.21	1202.39	296.80	13.52	1308.00
173.40	1299.08	1208.38	401.80	13.52	1314.00
185.20	1259.68	1214.58	514.80	13.51	1320.00
197.00	1195.10	1221.99	606.40	13.51	1324.00
202.80	1149.68	1226.66	700.00	13.51	1327.36
210.00	1075.95	1233.49	700.20	12.17	1327.55
210.40	1041.69	1237.55	701.60	13.64	1327.33
211.40	935.28	1243.93	701.80	13.44	1327.33
212.80	807.54	1251.71	702.00	13.91	1327.26
214.40	686.31	1259.46	702.40	14.54	1327.16
215.80	594.22	1265.49	703.40	15.58	1327.03
217.40	500.69	1271.71	704.40	16.25	1326.98
218.80	410.06	1276.74	705.40	16.69	1326.96
219.60	365.44	1279.18	707.00	17.07	1326.99
220.40	326.41	1281.30	708.40	17.16	1327.03
221.80	268.23	1284.59	716.00	16.27	1327.25
222.40	246.19	1285.87	720.00	16.11	1327.38
223.20	220.21	1287.43	791.40	16.28	1328.68
223.80	203.05	1288.50	1000.00	16.28	1331.00
225.40	164.39	1290.88	1200.00	16.28	1333.00
226.80	136.30	1292.81	1400.00	16.28	1335.00
227.60	122.90	1293.77	1600.00	16.28	1337.00
228.40	111.32	1294.61	1800.20	16.28	1338.10
229.80	93.46	1295.95	1800.40	16.40	1338.09
230.60	84.61	1296.66	1800.80	16.29	1338.13
232.20	70.07	1297.78	1801.40	15.64	1338.26
232.80	65.14	1298.21	1801.60	15.28	1338.33
233.60	59.45	1298.72	1802.00	14.25	1338.53
235.00	51.46	1299.53	1802.20	13.47	1338.66
236.40	44.51	1300.29	1802.60	13.51	1338.72
240.40	26.26	1302.29	1802.80	.00	.00
240.60	26.17	1302.34	1900.00	.00	.00
240.80	24.10	1302.54			

TABLE 6.5.2-5
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.8 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	269.00	25.06	1302.52
.20	1661.01	1190.41	269.20	23.65	1302.66
3.20	1590.29	1191.95	269.80	22.49	1302.85
6.20	1538.43	1193.07	270.60	20.11	1303.17
12.40	1466.73	1194.57	271.00	18.39	1303.39
18.40	1430.88	1195.28	271.40	18.13	1303.46
24.40	1415.02	1195.59	271.80	17.47	1303.58
24.60	1476.76	1195.30	273.40	13.63	1304.13
26.20	1596.45	1192.90	273.80	12.56	1304.30
28.20	1722.65	1190.05	274.40	12.00	1304.43
30.20	1816.07	1187.89	277.00	11.98	1304.53
32.20	1848.00	1187.19	277.20	11.87	1304.54
40.20	1758.94	1189.35	277.40	12.29	1304.49
58.60	1584.07	1193.33	277.80	12.84	1304.42
85.20	1367.00	1197.67	278.80	13.70	1304.38
98.40	1283.53	1199.11	279.80	14.21	1304.41
111.60	1225.39	1200.06	280.80	14.51	1304.46
124.80	1199.04	1200.46	282.80	14.70	1304.61
179.00	1193.49	1202.07	285.80	14.39	1304.81
192.60	1174.31	1208.31	291.40	13.44	1305.25
206.20	1137.40	1214.43	294.40	13.30	1305.47
219.80	1075.51	1222.11	306.20	13.55	1306.17
226.60	1029.91	1227.05	399.20	13.52	1312.00
235.00	954.39	1236.64	492.00	13.52	1317.00
235.20	929.11	1237.97	600.00	13.51	1322.00
236.80	795.33	1247.22	702.60	13.51	1325.75
238.40	683.94	1255.03	703.60	12.38	1325.94
240.20	578.06	1262.71	704.00	12.02	1326.01
241.80	495.73	1268.80	704.60	11.77	1326.04
242.60	449.04	1271.75	705.20	11.91	1326.02
244.40	358.55	1277.48	709.40	14.68	1325.70
245.40	315.76	1280.12	712.00	15.86	1325.61
246.20	285.94	1281.98	714.40	16.50	1325.56
248.00	228.52	1285.73	718.60	16.82	1325.58
248.80	206.80	1287.21	728.60	16.23	1325.88
249.60	187.71	1288.41	1000.00	16.28	1330.00
250.60	167.15	1289.88	1200.00	16.28	1332.00
252.40	135.30	1292.24	1400.00	16.28	1334.00
253.20	123.20	1293.16	1600.00	16.28	1336.00
254.00	112.44	1294.00	1800.80	16.29	1336.83
254.80	102.96	1294.75	1801.20	16.07	1336.88
257.40	77.44	1296.77	1801.80	15.42	1337.05
259.80	60.64	1298.38	1802.40	14.37	1337.27
260.80	54.78	1298.97	1802.80	13.36	1337.45
262.40	47.46	1299.78	1803.00	12.68	1337.59
264.20	40.52	1300.61	1803.20	11.72	1337.74
267.60	29.13	1301.97	1803.40	.00	.00
268.60	26.40	1302.35	1900.00	.00	.00

TABLE 6.5.2-6
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.7 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	307.40	17.65	1303.55
.20	1456.83	1190.40	308.60	16.50	1303.79
7.20	1350.69	1193.04	311.00	13.44	1304.32
14.00	1296.14	1194.34	312.20	11.54	1304.67
27.60	1261.13	1195.14	312.80	10.20	1304.90
27.80	1312.47	1194.81	313.20	10.58	1304.87
31.60	1544.24	1189.08	313.60	10.63	1304.90
33.60	1623.26	1186.98	315.80	10.51	1304.98
35.40	1647.11	1186.38	317.00	12.05	1304.78
64.60	1423.28	1192.41	318.40	13.15	1304.73
93.80	1233.91	1196.88	319.80	13.84	1304.76
123.20	1099.62	1199.56	321.40	14.32	1304.81
137.80	1069.75	1200.11	324.60	14.63	1304.93
193.60	1066.02	1201.22	336.00	13.41	1305.76
213.60	1050.04	1207.15	339.80	13.28	1306.00
233.60	1008.66	1214.69	355.00	13.56	1306.87
253.60	925.50	1225.34	402.20	13.52	1310.00
265.40	841.07	1235.49	496.60	13.52	1314.00
268.60	643.84	1252.15	600.80	13.51	1320.00
273.60	408.95	1271.01	706.20	13.51	1323.87
276.00	315.29	1277.78	707.60	12.63	1324.03
277.20	276.12	1280.60	709.00	12.46	1324.08
278.60	237.70	1283.43	711.60	13.33	1323.97
281.00	183.13	1287.63	716.80	15.59	1323.78
282.20	161.49	1289.21	719.60	16.34	1323.71
283.60	140.42	1290.91	725.40	16.86	1323.76
286.00	110.07	1293.44	743.40	16.17	1324.22
287.20	97.82	1294.50	997.80	16.28	1329.00
288.60	85.88	1295.58	1200.00	16.28	1331.00
291.00	68.56	1297.13	1400.00	16.28	1332.00
293.60	54.82	1298.61	1600.00	16.28	1334.00
296.00	44.91	1299.74	1800.00	16.28	1335.00
298.60	37.27	1300.74	1801.00	16.24	1335.28
303.20	26.33	1302.24	1802.40	15.12	1335.59
303.60	25.81	1302.34	1803.40	13.55	1335.94
305.00	22.21	1302.83	1803.80	11.72	1336.22
305.60	21.40	1302.97	1804.00	.00	.00
306.00	20.09	1303.15	1900.00	.00	.00
306.40	19.96	1303.21			

TABLE 6.5.2-7
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.6 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	355.80	18.92	1303.44
.20	1251.59	1190.38	356.20	18.82	1303.49
8.60	1161.98	1192.99	356.80	17.82	1303.65
17.00	1120.93	1194.14	358.40	16.77	1303.91
34.00	1102.29	1194.65	365.20	11.20	1305.12
34.20	1143.59	1194.33	366.80	10.20	1305.35
38.00	1347.37	1188.35	368.40	9.83	1305.49
40.00	1419.57	1186.08	370.00	10.13	1305.52
42.00	1444.48	1185.33	375.40	12.24	1305.49
108.40	1092.49	1196.01	378.40	13.11	1305.51
141.60	969.46	1198.98	381.40	13.67	1305.57
158.20	935.84	1199.72	387.40	14.03	1305.84
223.40	931.37	1200.88	407.00	13.42	1307.02
247.60	915.05	1207.70	494.40	13.52	1312.00
271.80	876.02	1214.78	593.40	13.52	1317.00
295.80	793.23	1226.65	712.40	13.51	1321.56
307.80	720.48	1237.37	715.20	12.80	1321.72
310.80	572.12	1251.00	717.00	12.97	1321.71
316.80	350.39	1271.38	727.20	15.95	1321.46
320.00	260.57	1279.03	729.40	16.34	1321.43
321.40	228.60	1281.78	736.40	16.80	1321.52
324.40	173.76	1286.63	759.20	16.19	1322.08
326.00	150.15	1288.61	1000.00	16.28	1327.00
327.40	132.94	1290.18	1200.00	16.28	1329.00
329.00	116.21	1291.74	1400.00	16.28	1330.00
332.00	90.09	1294.30	1600.00	16.28	1332.00
333.40	80.46	1295.30	1800.00	16.28	1333.00
335.00	71.30	1296.19	1801.20	16.20	1333.36
338.00	56.56	1297.85	1803.40	14.63	1333.83
341.00	45.82	1299.22	1804.00	11.14	1334.39
342.60	41.05	1299.85	1804.20	9.56	1334.66
344.20	37.29	1300.39	1804.60	8.15	1334.87
347.20	31.48	1301.24	1804.80	.00	.00
353.00	22.63	1302.77	1900.00	.00	.00

TABLE 6.5.2-8
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.5 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	414.20	25.65	1302.19
.20	1045.32	1190.37	420.60	20.22	1303.42
7.60	987.69	1192.39	421.00	20.08	1303.48
15.20	957.13	1193.44	421.80	19.31	1303.63
48.80	938.60	1194.06	422.20	19.20	1303.68
49.00	971.11	1193.69	422.60	18.74	1303.77
51.00	1071.74	1190.27	423.60	18.34	1303.91
53.00	1155.14	1187.12	423.80	17.92	1303.97
55.00	1212.83	1184.93	435.00	12.53	1305.45
57.00	1230.45	1184.29	436.60	11.93	1305.63
124.40	974.27	1193.92	438.20	11.49	1305.78
146.80	903.23	1196.24	439.80	11.23	1305.89
169.20	842.35	1198.04	441.40	11.15	1305.98
191.60	798.94	1199.23	443.00	11.23	1306.04
202.80	788.95	1199.49	444.60	11.43	1306.08
262.20	790.94	1201.05	454.00	13.08	1306.22
287.80	779.03	1206.81	460.20	13.70	1306.42
313.40	754.18	1212.85	466.60	13.88	1306.71
326.20	733.72	1216.74	486.80	13.48	1307.79
339.00	704.12	1221.80	542.40	13.52	1311.00
351.80	660.95	1228.69	644.60	13.52	1316.00
364.60	600.09	1237.79	719.40	13.51	1318.74
367.80	492.03	1249.94	724.00	13.05	1318.90
369.40	444.72	1255.34	726.00	13.27	1318.91
374.20	315.53	1269.41	738.80	15.88	1318.71
375.80	279.51	1273.12	742.40	16.30	1318.70
377.40	247.61	1276.46	746.40	16.57	1318.74
379.00	218.66	1279.50	750.60	16.67	1318.82
380.60	193.27	1282.16	782.40	16.23	1319.52
382.20	171.54	1284.44	1000.00	16.28	1324.00
383.80	152.06	1286.36	1200.00	16.28	1327.00
385.40	134.70	1288.20	1400.00	16.28	1328.00
387.00	119.82	1289.81	1600.00	16.28	1330.00
388.60	107.18	1291.21	1800.00	16.28	1331.00
390.20	96.06	1292.48	1800.40	16.30	1331.05
391.80	85.98	1293.66	1801.40	16.20	1331.13
393.40	77.09	1294.73	1803.00	15.56	1331.41
395.00	69.40	1295.58	1803.60	15.20	1331.52
396.60	62.83	1296.42	1804.60	12.03	1332.04
399.80	51.71	1297.91	1805.00	10.63	1332.26
401.40	47.04	1298.58	1805.20	9.85	1332.40
403.00	43.25	1299.18	1805.40	8.95	1332.56
406.00	36.90	1300.19	1805.60	7.74	1332.74
406.20	36.17	1300.27	1805.80	.00	.00
407.80	33.48	1300.66	1900.00	.00	.00
411.60	28.46	1301.61			

TABLE 6.5.2-9
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.4 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	515.00	24.35	1302.26
.20	838.06	1190.35	518.20	22.42	1302.78
7.60	800.76	1191.99	521.40	20.76	1303.27
15.00	780.97	1192.85	524.40	19.46	1303.68
43.80	767.87	1193.41	530.80	17.27	1304.46
59.60	767.95	1193.40	540.00	14.64	1305.39
59.80	792.31	1193.06	543.40	13.76	1305.73
61.60	866.21	1189.86	546.60	13.10	1305.99
63.80	942.06	1186.27	549.80	12.64	1306.21
66.00	994.26	1183.74	553.00	12.38	1306.38
68.20	1009.01	1183.07	556.00	12.31	1306.51
145.20	822.25	1192.05	560.60	12.43	1306.66
168.20	771.82	1194.26	574.40	13.26	1307.02
218.00	680.77	1197.80	583.60	13.57	1307.36
243.00	648.56	1198.92	592.80	13.65	1307.76
255.40	640.99	1199.17	630.60	13.50	1309.52
328.00	644.96	1202.22	730.40	13.52	1314.17
370.40	629.66	1208.46	734.60	13.20	1314.33
391.60	614.82	1212.36	737.20	13.30	1314.38
412.80	589.75	1217.79	741.00	13.72	1314.40
434.00	547.23	1226.26	749.40	14.94	1314.31
444.60	516.38	1231.48	759.20	15.95	1314.29
455.60	476.80	1238.79	765.80	16.29	1314.37
459.00	398.54	1249.85	778.00	16.47	1314.68
464.60	292.61	1264.64	874.40	16.28	1317.00
466.20	264.97	1268.31	968.40	16.28	1318.31
467.80	240.23	1271.54	1000.00	16.28	1319.00
470.80	200.97	1276.80	1200.00	16.28	1323.00
474.00	165.27	1281.51	1400.00	16.28	1325.00
475.60	150.12	1283.47	1600.00	16.28	1326.00
477.20	136.80	1285.09	1800.20	16.28	1327.46
480.40	113.24	1288.21	1802.40	16.07	1327.68
482.00	103.18	1289.58	1804.00	15.57	1327.90
483.60	94.31	1290.80	1805.60	12.91	1328.38
486.80	79.58	1292.88	1806.80	10.73	1328.75
489.80	67.88	1294.51	1807.40	9.52	1328.97
491.40	62.47	1295.34	1807.80	8.63	1329.11
494.40	53.82	1296.68	1808.20	7.61	1329.30
496.00	50.05	1297.32	1808.40	7.01	1329.43
500.80	40.34	1298.98	1808.60	6.21	1329.59
502.40	37.70	1299.47	1809.00	5.56	1329.73
507.40	31.07	1300.72	1809.20	.00	.00
511.00	27.32	1301.52	1900.00	.00	.00

TABLE 6.5.2-10
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.3 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	711.40	15.39	1305.30
.20	629.92	1190.33	716.80	14.73	1305.66
9.40	605.12	1191.79	722.00	14.26	1305.97
18.40	594.19	1192.43	732.40	13.68	1306.48
77.80	589.43	1192.70	748.80	13.39	1307.14
79.60	657.76	1189.36	753.20	13.20	1307.25
82.00	721.40	1185.30	757.20	13.32	1307.31
83.20	746.41	1183.67	783.00	15.31	1307.15
84.40	763.17	1182.59	797.60	15.96	1307.31
86.60	772.71	1182.00	820.60	16.29	1307.69
130.40	722.10	1185.42	908.20	16.29	1310.00
236.40	584.16	1193.96	1000.00	16.29	1311.00
295.00	525.93	1197.06	1200.00	16.29	1316.00
336.80	493.60	1198.60	1400.00	16.29	1320.00
357.60	487.41	1198.88	1600.00	16.28	1323.00
420.00	494.90	1200.13	1800.00	16.28	1324.00
461.60	489.85	1203.94	1801.80	16.23	1323.68
503.20	478.35	1208.49	1804.60	15.83	1323.99
544.80	454.02	1215.39	1804.80	15.57	1324.04
565.60	432.14	1221.18	1809.80	11.79	1324.92
586.60	398.57	1230.14	1811.80	10.03	1325.36
607.80	351.03	1241.81	1812.00	10.06	1325.38
617.80	233.01	1262.98	1812.20	9.57	1325.48
620.40	206.89	1267.70	1812.40	9.68	1325.48
623.00	183.87	1271.85	1812.60	9.18	1325.57
625.60	164.15	1275.43	1812.80	9.29	1325.58
628.20	146.39	1278.60	1813.00	8.77	1325.68
630.80	130.33	1281.32	1813.20	8.88	1325.69
633.40	116.21	1283.80	1813.40	8.35	1325.75
636.00	104.07	1285.93	1813.60	8.47	1325.76
638.60	93.23	1287.86	1813.80	7.91	1325.86
641.20	83.47	1289.62	1814.00	8.04	1325.86
643.80	75.00	1291.15	1814.20	7.45	1325.97
646.40	67.75	1292.53	1814.40	7.59	1325.97
651.60	55.89	1294.74	1814.60	6.97	1326.08
654.20	50.82	1295.77	1814.80	7.12	1326.08
656.80	46.32	1296.68	1815.00	6.45	1326.21
661.20	40.04	1298.04	1815.20	6.61	1326.19
664.60	36.23	1298.92	1815.40	5.88	1326.35
669.80	31.15	1300.12	1815.60	6.06	1326.33
672.40	28.96	1300.60	1815.80	5.19	1326.50
682.00	23.26	1302.24	1816.00	5.43	1326.47
687.40	20.93	1302.98	1816.40	4.71	1326.63
695.80	18.49	1303.92	1816.60	.00	.00
701.00	17.27	1304.45	1900.00	.00	.00

TABLE 6.5.2-11
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.2 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	1028.20	27.16	1297.90
.20	420.79	1190.32	1037.40	24.32	1298.71
14.20	406.38	1191.60	1046.40	22.20	1299.37
41.60	402.23	1191.96	1055.40	20.59	1299.87
113.80	402.28	1191.95	1071.60	18.77	1300.51
114.00	412.75	1191.55	1083.00	18.03	1300.86
114.40	423.38	1190.77	1101.20	17.23	1301.29
116.20	459.09	1187.41	1119.40	16.77	1301.64
118.40	497.20	1183.69	1156.00	16.40	1302.23
119.60	512.80	1182.15	1200.00	16.31	1303.00
120.80	522.57	1181.19	1400.00	16.29	1307.00
123.20	527.84	1180.70	1600.00	16.29	1312.00
148.40	524.14	1181.09	1799.60	16.29	1315.57
325.40	428.36	1190.51	1803.00	16.15	1315.84
426.60	384.22	1194.41	1805.80	15.64	1316.19
578.40	332.10	1198.50	1809.00	13.99	1316.67
603.80	328.43	1200.26	1812.00	12.73	1317.19
629.00	332.84	1201.43	1815.40	11.48	1317.77
679.60	335.48	1202.48	1827.00	7.60	1319.44
730.20	330.54	1205.90	1828.60	6.98	1319.68
780.80	322.03	1208.80	1828.80	6.77	1319.73
831.40	303.51	1215.97	1829.40	6.65	1319.80
856.80	290.85	1220.56	1830.20	6.30	1319.93
882.00	273.41	1227.21	1830.40	6.08	1319.97
907.20	250.64	1235.64	1830.60	6.13	1319.98
938.60	218.07	1247.06	1830.80	5.90	1320.04
942.60	197.22	1251.27	1831.00	5.95	1320.05
949.40	165.73	1260.32	1831.20	5.72	1320.11
953.00	150.93	1264.57	1831.40	5.77	1320.11
959.80	125.20	1271.76	1832.00	5.33	1320.23
964.40	110.35	1275.72	1832.20	5.39	1320.24
969.00	97.43	1279.24	1832.80	4.93	1320.37
973.40	86.43	1282.16	1833.60	4.50	1320.52
978.00	76.65	1284.76	1833.80	4.56	1320.52
982.60	68.27	1286.94	1834.40	4.01	1320.66
987.20	60.97	1288.88	1834.60	4.09	1320.66
991.80	54.61	1290.50	1834.80	3.74	1320.75
996.40	49.15	1291.98	1835.00	3.82	1320.74
1001.00	44.34	1293.29	1835.20	3.41	1320.84
1005.40	40.33	1294.38	1835.40	3.52	1320.83
1010.00	36.74	1295.36	1835.60	2.93	1320.98
1014.40	33.81	1296.15	1835.80	3.13	1320.95
1019.00	31.20	1296.85	1836.00	.00	.00
1023.60	28.99	1297.46	1900.00	.00	.00

TABLE 6.5.2-12
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
100% POWER, 0.1 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	2041.00	3.55	1310.26
.20	210.87	1190.30	2041.20	3.48	1310.28
12.40	207.40	1190.91	2041.60	3.49	1310.31
221.40	206.03	1191.15	2041.80	3.41	1310.34
221.80	213.73	1190.37	2042.20	3.43	1310.37
224.20	238.00	1185.81	2042.40	3.35	1310.40
226.80	259.52	1181.50	2043.00	3.36	1310.44
228.20	266.58	1180.11	2043.20	3.26	1310.47
229.60	269.94	1179.42	2043.40	3.29	1310.48
243.40	273.06	1178.79	2043.80	3.28	1310.52
324.40	271.35	1179.15	2044.40	3.20	1310.57
410.60	264.9	1181.00	2044.80	3.09	1310.63
469.80	260.1	1182.00	2045.20	3.11	1310.64
588.60	250.3	1184.00	2045.60	3.00	1310.70
711.80	240.3	1186.00	2046.00	3.02	1310.72
844.00	230.0	1188.00	2046.40	2.90	1310.78
895.60	225.52	1192.42	2046.60	2.94	1310.78
949.60	218.43	1194.35	2047.00	2.92	1310.82
1200.00	192.5	1201.00	2047.60	2.84	1310.87
1463.80	169.60	1206.59	2048.00	2.72	1310.93
1636.40	155.99	1211.40	2048.20	2.75	1310.94
1729.60	154.96	1215.37	2048.60	2.74	1310.97
1800.20	149.27	1218.81	2048.80	2.62	1311.01
1813.00	130.29	1230.87	2049.00	2.65	1311.01
1857.80	72.71	1267.13	2049.40	2.64	1311.05
1870.80	58.90	1275.13	2049.60	2.52	1311.09
1877.20	53.26	1278.37	2050.00	2.54	1311.10
1890.00	43.20	1283.98	2050.60	2.45	1311.17
1896.40	38.84	1286.38	2051.00	2.43	1311.20
1902.80	35.05	1288.52	2051.40	2.34	1311.25
1915.60	28.37	1292.32	2051.80	2.33	1311.28
1922.00	25.50	1293.97	2052.20	2.23	1311.32
1928.40	22.99	1295.41	2052.60	2.21	1311.35
1941.40	18.73	1298.03	2052.80	2.07	1311.40
1947.80	16.87	1299.22	2053.20	2.10	1311.41
1962.00	13.39	1301.54	2053.80	1.98	1311.48
1983.20	9.53	1304.37	2054.20	1.97	1311.52
1995.60	7.89	1305.83	2054.40	1.78	1311.58
1995.80	7.81	1305.86	2054.60	1.84	1311.57
1996.80	7.73	1305.97	2054.80	1.83	1311.59
2004.60	6.75	1306.78	2055.00	1.67	1311.64
2011.80	6.06	1307.49	2055.20	1.72	1311.64
2037.00	3.89	1309.89	2055.40	1.71	1311.66
2037.40	3.90	1309.92	2055.60	1.49	1311.73
2037.60	3.83	1309.95	2055.80	1.57	1311.72
2038.00	3.84	1309.98	2056.00	1.55	1311.74
2038.60	3.78	1310.03	2056.20	.00	.00
2038.80	3.71	1310.06	2100.00	.00	.00
2039.20	3.73	1310.09			

TABLE 6.5.2-13
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 1.0 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	251.40	24.87	1302.52
.20	2152.38	1189.48	251.60	22.29	1302.77
3.00	2049.84	1191.30	251.80	22.51	1302.78
5.80	1973.97	1192.65	252.00	20.23	1303.03
11.40	1867.47	1194.47	252.20	20.28	1303.05
17.00	1804.73	1195.48	252.40	18.34	1303.27
22.80	1771.04	1196.00	252.60	18.15	1303.31
23.00	1816.52	1195.83	253.00	16.54	1303.53
26.40	1996.84	1192.89	253.20	15.53	1303.61
28.20	2064.78	1191.70	253.40	13.90	1303.82
30.00	2090.94	1191.26	256.80	14.95	1303.86
31.60	2079.61	1191.49	257.00	14.04	1303.97
50.40	1813.25	1196.06	257.20	14.52	1303.91
60.80	1689.50	1197.91	257.80	15.00	1303.87
71.00	1586.88	1199.32	258.40	15.22	1303.90
81.20	1510.84	1200.29	259.20	15.31	1303.96
91.40	1468.15	1200.81	261.20	14.97	1304.17
123.20	1448.41	1201.04	263.20	14.37	1304.37
174.40	1446.60	1202.55	265.20	14.01	1304.47
185.60	1425.23	1208.79	414.40	13.98	1310.00
196.80	1384.84	1214.73	506.40	13.98	1313.00
208.20	1319.83	1221.82	603.20	13.98	1316.00
219.40	1218.93	1230.86	694.00	13.98	1317.99
222.60	1181.51	1236.02	695.40	15.01	1317.84
223.00	1117.54	1238.99	695.60	14.27	1317.93
223.40	1067.19	1241.72	695.80	14.75	1317.85
225.20	874.39	1251.88	696.80	15.71	1317.71
226.60	754.80	1258.67	697.60	16.15	1317.66
228.00	651.84	1264.72	699.00	16.58	1317.66
229.40	562.38	1269.98	701.20	16.77	1317.70
231.40	451.67	1276.46	706.40	16.40	1317.77
232.80	363.18	1281.12	711.60	16.22	1317.86
233.60	320.92	1283.26	800.00	16.28	1319.00
234.40	282.50	1285.21	900.00	16.28	1320.00
235.00	257.04	1286.53	1000.00	16.28	1322.00
235.60	234.47	1287.74	1200.00	16.28	1323.00
236.40	208.46	1289.18	1400.00	16.28	1323.00
237.80	169.14	1291.35	1600.00	16.28	1323.00
238.40	154.63	1292.26	1800.00	16.28	1322.45
239.20	137.63	1293.36	1800.40	16.47	1322.43
239.80	126.56	1294.10	1800.80	16.36	1322.45
241.80	95.34	1296.30	1801.20	15.91	1322.55
243.60	75.16	1297.78	1801.60	15.02	1322.70
244.40	67.59	1298.39	1801.80	14.21	1322.81
245.00	62.90	1298.79	1802.00	.00	.00
246.40	53.43	1299.66	1900.00	.00	.00
251.20	25.03	1302.47			

TABLE 6.5.2-14
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.9 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	280.20	13.90	1303.83
.20	1940.90	1189.47	280.40	12.66	1303.99
6.40	1783.42	1192.58	283.80	13.49	1303.98
12.60	1692.95	1194.30	284.00	13.07	1304.03
25.00	1619.25	1195.62	284.40	13.76	1303.94
25.80	1694.09	1194.86	285.40	14.57	1303.89
30.60	1894.38	1190.99	286.80	15.05	1303.94
32.40	1916.11	1190.60	288.00	15.16	1304.01
54.80	1663.64	1195.52	296.00	13.93	1304.43
77.00	1459.60	1198.86	386.60	13.98	1308.00
88.00	1388.23	1199.91	484.40	13.98	1311.00
99.20	1345.90	1200.49	613.40	13.98	1315.00
177.60	1329.49	1201.00	696.20	13.98	1316.81
203.40	1304.98	1208.66	696.60	12.78	1316.98
229.00	1205.57	1221.67	697.00	14.20	1316.80
245.60	1066.51	1236.55	697.20	13.28	1316.92
245.80	1035.45	1237.96	697.80	12.73	1317.00
248.20	808.31	1251.49	698.60	12.68	1317.00
249.80	691.56	1258.84	701.60	14.45	1316.77
251.40	591.62	1265.32	704.80	15.78	1316.65
256.20	338.29	1280.86	708.00	16.42	1316.60
257.80	270.50	1284.66	711.20	16.59	1316.60
259.40	216.09	1287.86	720.60	16.26	1316.76
261.00	174.99	1290.32	780.20	16.28	1318.00
262.60	141.28	1292.61	932.40	16.28	1320.00
264.20	115.15	1294.49	1000.00	16.28	1320.00
266.60	85.23	1296.75	1200.00	16.28	1323.00
269.00	64.44	1298.40	1400.00	16.28	1323.00
270.60	54.34	1299.34	1600.00	16.28	1322.00
272.20	46.13	1300.18	1800.00	16.28	1322.00
276.40	27.32	1302.15	1800.80	16.34	1322.40
276.60	27.22	1302.19	1801.40	15.87	1322.49
276.80	25.22	1302.38	1802.00	14.90	1322.70
277.00	25.41	1302.40	1802.40	13.80	1322.88
277.60	21.94	1302.78	1802.60	12.87	1323.01
278.60	18.14	1303.26	1802.80	.00	.00
278.80	18.18	1303.27	1900.00	.00	.00
280.00	14.72	1303.71			

TABLE 6.5.2-15
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.8 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	313.80	12.45	1304.00
.20	1728.46	1189.45	314.40	11.72	1304.13
7.20	1591.05	1192.51	317.40	11.98	1304.13
14.00	1517.90	1194.08	317.60	11.85	1304.14
27.80	1463.89	1195.18	318.00	12.57	1304.04
28.60	1530.63	1194.36	318.60	13.23	1303.98
33.20	1709.85	1190.43	320.00	14.16	1303.94
35.20	1734.16	1189.90	322.20	14.84	1303.99
60.00	1510.98	1194.88	324.40	15.02	1304.06
85.00	1323.91	1198.42	333.40	14.00	1304.45
97.40	1256.86	1199.55	338.00	13.80	1304.64
109.80	1217.27	1200.18	351.40	14.01	1305.08
136.60	1200.10	1200.45	395.00	13.98	1307.00
195.00	1204.16	1200.66	497.80	13.98	1310.00
224.80	1181.71	1208.28	595.60	13.98	1313.00
239.60	1147.03	1214.16	698.80	13.98	1315.50
254.60	1088.49	1221.39	700.00	12.79	1315.68
273.80	951.07	1236.88	701.20	12.39	1315.74
274.80	858.35	1242.86	703.60	13.31	1315.60
276.80	713.32	1252.74	707.40	15.17	1315.40
278.80	596.96	1261.03	710.40	16.12	1315.31
280.60	507.54	1267.49	719.80	16.66	1315.31
284.40	335.12	1279.09	812.60	16.28	1317.00
286.20	268.15	1283.28	889.80	16.28	1318.00
288.00	214.01	1286.82	1000.00	16.28	1319.00
289.80	172.61	1289.56	1200.00	16.28	1322.00
291.80	136.72	1292.20	1400.00	16.28	1322.00
293.80	108.70	1294.36	1600.00	16.28	1322.00
296.80	78.45	1296.71	1800.00	16.28	1322.00
299.40	60.24	1298.39	1800.40	16.36	1322.31
301.20	50.70	1299.34	1801.40	16.03	1322.40
303.00	43.60	1300.14	1802.40	14.89	1322.67
308.60	24.67	1302.30	1803.00	13.72	1322.86
310.40	19.47	1302.98	1803.40	12.55	1323.06
310.60	19.53	1302.99	1803.60	11.63	1323.22
311.20	17.62	1303.24	1803.80	.00	.00
311.60	17.25	1303.31	1900.00	.00	.00
313.40	13.60	1303.82			

TABLE 6.5.2-16
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.7 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	353.20	19.74	1302.90
.20	1515.11	1189.44	53.40	18.76	1303.01
8.00	1400.17	1192.37	354.00	18.33	1303.10
15.80	1341.09	1193.82	357.40	14.04	1303.77
31.20	1304.72	1194.69	358.40	12.53	1304.03
31.60	1342.58	1194.28	359.40	10.56	1304.35
35.00	1476.92	1190.93	359.60	9.91	1304.46
37.00	1532.02	1189.49	362.40	10.45	1304.39
38.80	1549.22	1189.07	363.60	11.91	1304.18
74.40	1304.43	1195.31	364.80	12.88	1304.11
92.80	1197.71	1197.65	367.00	13.98	1304.07
119.80	1091.43	1199.71	369.40	14.62	1304.08
148.80	1069.05	1200.12	372.80	14.93	1304.08
253.80	1053.70	1207.97	387.60	13.83	1304.71
271.40	1021.98	1213.79	407.60	14.01	1305.33
289.00	967.36	1221.35	483.60	13.98	1308.00
311.00	837.12	1236.35	587.60	13.98	1311.00
313.20	700.71	1247.45	702.40	13.98	1313.80
315.40	585.89	1256.60	705.40	12.91	1313.97
317.60	490.69	1264.39	706.80	13.06	1313.97
322.00	322.07	1277.35	714.20	15.53	1313.70
324.20	253.13	1282.29	718.00	16.36	1313.62
326.40	199.71	1286.30	723.60	16.79	1313.68
328.60	158.34	1289.42	753.80	16.27	1314.10
330.80	127.06	1291.98	868.80	16.28	1316.00
333.00	101.93	1294.11	1000.00	16.28	1317.00
335.20	83.19	1295.78	1200.00	16.28	1320.00
337.40	67.61	1297.13	1400.00	16.28	1322.00
339.80	55.20	1298.45	1600.00	16.28	1322.00
342.00	45.96	1299.46	1801.00	16.27	1322.26
344.20	39.29	1300.28	1802.20	15.59	1322.47
346.40	33.69	1300.95	1803.80	13.51	1322.89
350.60	24.20	1302.23	1804.20	12.74	1323.03
350.80	24.23	1302.26	1804.40	10.45	1323.36
352.00	21.25	1302.64	1804.60	.00	.00
352.60	20.17	1302.80	1900.00	.00	.00

TABLE 6.5.2-17
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.6 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	409.60	19.40	1302.84
.20	1300.89	1189.42	410.40	18.95	1302.94
9.20	1206.51	1192.23	410.80	18.12	1303.06
18.00	1163.02	1193.49	414.40	15.37	1303.55
35.80	1140.40	1194.13	418.40	11.95	1304.21
36.20	1171.63	1193.70	420.40	10.51	1304.48
41.60	1339.26	1188.69	421.40	10.03	1304.57
43.60	1356.58	1188.18	422.60	9.82	1304.64
104.00	1060.06	1196.83	424.40	10.17	1304.62
134.20	959.86	1199.19	429.80	12.31	1304.44
165.80	933.03	1199.78	433.20	13.35	1304.35
262.00	938.44	1200.54	436.80	14.07	1304.32
294.20	918.99	1208.18	444.00	14.53	1304.45
326.20	866.58	1217.69	466.00	13.87	1305.19
342.20	815.30	1224.91	554.60	13.98	1308.00
360.80	716.36	1237.59	707.00	13.98	1311.75
362.40	633.64	1245.02	710.60	13.23	1311.89
364.40	548.14	1252.95	713.40	13.53	1311.87
366.40	475.85	1259.82	722.00	15.62	1311.64
372.40	290.51	1276.46	727.80	16.48	1311.57
374.40	240.73	1280.69	733.40	16.75	1311.65
376.40	200.72	1284.17	764.60	16.22	1312.07
378.40	166.92	1287.05	878.80	16.28	1314.00
380.40	139.64	1289.52	1000.00	16.28	1315.00
382.40	118.03	1291.52	1200.00	16.28	1318.00
384.40	99.57	1293.28	1400.00	16.28	1320.00
386.40	84.42	1294.79	1600.00	16.28	1322.00
388.40	72.46	1295.94	1800.00	16.28	1322.00
390.40	62.12	1297.05	1801.20	16.24	1322.17
392.40	53.86	1298.03	1802.40	15.74	1322.35
394.40	46.76	1298.89	1804.40	13.96	1322.75
396.40	40.82	1299.63	1804.60	11.67	1323.09
398.40	36.34	1300.25	1804.80	10.76	1323.23
402.40	29.24	1301.26	1805.00	8.81	1323.54
406.20	24.01	1302.11	1805.20	.00	.00
406.40	23.47	1302.18	1900.00	.00	.00

TABLE 6.5.2-18
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.5 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	485.20	22.89	1302.04
.20	1085.85	1189.41	491.00	18.66	1302.90
9.40	1018.45	1191.82	502.80	12.78	1304.17
18.60	986.91	1192.93	506.20	11.62	1304.44
42.00	970.57	1193.49	509.60	11.23	1304.56
47.00	1120.46	1188.51	513.00	11.51	1304.59
50.20	1156.40	1187.21	526.20	13.80	1304.44
120.20	913.31	1195.93	537.60	14.39	1304.59
155.00	822.61	1198.59	653.60	13.98	1308.00
172.40	797.55	1199.26	713.20	13.98	1309.10
287.60	798.87	1199.22	717.60	13.46	1309.23
343.00	785.41	1206.58	721.20	13.71	1309.22
370.80	761.41	1211.64	732.60	15.61	1309.00
398.60	714.70	1220.42	740.00	16.38	1308.99
412.40	675.97	1225.96	747.60	16.65	1309.04
431.60	594.20	1238.29	794.80	16.26	1309.57
433.00	542.47	1243.93	877.60	16.28	1311.00
436.40	440.20	1255.45	1000.00	16.28	1312.00
443.40	273.84	1273.58	1200.00	16.28	1315.00
447.00	207.61	1280.47	1400.00	16.28	1317.00
450.40	160.86	1285.38	1600.00	16.28	1320.00
452.20	140.36	1287.41	1800.00	16.28	1322.00
454.00	122.92	1289.27	1801.80	16.15	1321.79
457.40	97.21	1292.10	1804.60	14.80	1322.25
460.80	77.05	1294.44	1805.00	13.12	1322.49
464.20	62.16	1296.17	1805.80	10.41	1322.93
467.80	50.00	1297.73	1806.20	8.65	1323.23
473.00	37.63	1299.51	1806.40	7.12	1323.46
474.80	34.41	1300.02	1806.60	.00	.00
478.20	29.74	1300.73	1900.00	.00	.00
481.80	25.83	1301.45			

TABLE 6.5.2-19
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.4 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	594.40	29.64	1300.17
.20	870.04	1189.39	597.60	26.66	1300.76
9.40	826.30	1191.36	604.00	22.52	1301.69
18.80	805.14	1192.30	610.40	19.62	1302.44
51.80	793.90	1192.79	629.60	13.93	1303.98
53.00	834.19	1191.39	636.00	12.83	1304.28
58.00	935.78	1186.66	642.40	12.50	1304.43
60.20	946.77	1186.18	648.80	12.73	1304.45
144.60	757.54	1194.85	666.40	13.84	1304.51
186.80	680.27	1197.82	675.20	14.09	1304.65
208.00	653.28	1198.76	732.80	13.84	1305.82
229.20	644.44	1199.05	750.80	15.71	1305.49
396.40	650.18	1202.39	762.00	16.31	1305.48
444.20	632.04	1208.05	774.00	16.48	1305.53
492.00	589.46	1217.97	842.80	16.28	1306.06
516.00	545.29	1226.59	887.40	16.28	1307.00
540.40	471.48	1239.28	1000.00	16.29	1308.00
546.40	347.52	1256.71	1200.00	16.29	1311.00
552.80	243.06	1270.90	1400.00	16.28	1313.00
556.00	200.98	1276.51	1600.00	16.28	1316.00
559.20	165.36	1281.21	1800.00	16.28	1318.00
562.40	136.96	1284.77	1800.40	16.30	1317.80
565.60	113.46	1287.84	1803.60	15.85	1318.12
568.80	94.58	1290.38	1805.00	15.37	1318.32
572.00	79.87	1292.41	1806.60	12.65	1318.80
575.20	67.51	1294.09	1808.20	9.63	1319.33
578.40	57.38	1295.57	1809.20	7.17	1319.76
581.60	49.53	1296.80	1809.60	.00	.00
584.80	43.02	1297.84	1900.00	.00	.00
588.00	37.53	1298.77			

TABLE 6.5.2-20
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.3 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	795.60	28.45	1298.96
.20	653.50	1189.37	806.40	23.29	1300.05
11.40	625.04	1191.08	813.00	20.97	1300.50
67.60	609.35	1192.02	819.40	19.37	1300.82
72.00	692.92	1187.21	832.60	17.44	1301.16
74.20	718.82	1185.57	845.80	16.61	1301.25
76.40	726.24	1185.13	883.00	16.18	1301.20
193.60	581.71	1194.10	1000.00	16.28	1302.00
281.40	497.91	1198.40	1200.00	16.29	1304.00
310.60	491.67	1198.68	1400.00	16.29	1307.00
451.20	500.96	1198.26	1600.00	16.28	1309.00
556.40	492.14	1203.94	1800.00	16.28	1312.00
609.00	478.17	1209.14	1801.60	16.27	1311.78
661.60	449.00	1216.85	1805.80	15.57	1312.18
687.80	420.61	1224.54	1813.80	9.37	1313.81
714.20	375.26	1235.69	1814.00	8.85	1313.90
727.40	345.88	1242.59	1814.60	8.56	1314.01
734.00	269.05	1255.80	1815.40	7.68	1314.19
740.40	205.45	1267.51	1815.60	7.07	1314.31
743.80	176.69	1272.68	1816.20	6.72	1314.42
750.20	134.04	1280.25	1816.40	6.01	1314.56
753.60	115.72	1283.27	1816.60	6.18	1314.54
760.20	88.28	1288.04	1816.80	5.35	1314.71
763.40	77.58	1289.89	1817.00	5.57	1314.68
766.80	68.41	1291.56	1817.20	4.30	1314.95
773.40	54.26	1294.04	1817.40	4.61	1314.89
780.00	43.64	1296.05	1817.60	.00	.00
786.60	35.85	1297.57	1900.00	.00	.00

TABLE 6.5.2-21
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.2 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	1247.00	24.74	1296.63
.20	436.28	1189.36	1263.60	21.03	1297.50
18.80	419.31	1190.89	1280.20	18.91	1297.99
99.40	416.03	1191.19	1296.40	17.86	1298.23
100.80	438.79	1189.40	1312.80	17.16	1298.36
104.00	476.38	1185.82	1345.40	16.52	1298.47
106.40	492.91	1184.23	1484.00	16.28	1299.16
170.60	470.64	1186.49	1799.00	16.29	1303.03
366.80	369.68	1195.61	1804.00	16.07	1303.34
463.40	334.44	1198.24	1807.80	15.24	1303.78
625.00	341.51	1197.74	1816.60	11.48	1305.22
754.00	339.73	1199.47	1828.60	7.44	1306.90
883.20	329.86	1205.15	1830.00	6.76	1307.12
1012.40	309.62	1213.63	1830.20	6.81	1307.13
1076.80	281.15	1224.47	1833.20	5.33	1307.60
1109.20	256.26	1233.39	1834.20	4.98	1307.74
1150.20	216.28	1244.95	1835.00	4.55	1307.87
1154.60	193.32	1251.51	1835.20	4.25	1307.94
1164.40	151.10	1263.53	1835.80	4.08	1308.00
1172.60	121.50	1271.76	1836.00	3.72	1308.08
1180.80	97.34	1278.21	1836.20	3.81	1308.08
1189.20	77.65	1283.32	1836.40	3.40	1308.18
1197.40	63.36	1287.00	1836.60	3.51	1308.17
1205.60	52.11	1289.82	1836.80	2.90	1308.31
1214.00	43.14	1292.14	1837.00	3.11	1308.28
1222.20	36.35	1293.88	1837.20	.00	.00
1230.40	31.25	1295.14	1900.00	.00	.00
1238.60	27.49	1296.04			

TABLE 6.5.2-22
STEAMLINE BREAK MASS & ENERGY RELEASES OUTSIDE CONTAINMENT
70% POWER, 0.1 FT^2 BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)	Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
.00	.00	.00	2154.60	5.26	1308.06
.20	218.44	1189.34	2174.80	3.55	1309.50
113.20	213.23	1190.29	2178.20	3.19	1309.74
193.60	213.23	1190.29	2178.60	3.08	1309.79
196.60	234.33	1186.59	2179.20	3.10	1309.82
199.80	250.18	1183.48	2182.20	2.74	1310.03
218.60	257.47	1182.08	2182.60	2.61	1310.08
243.80	258.02	1181.97	2183.00	2.64	1310.09
419.80	240.4	1186.00	2183.40	2.51	1310.14
569.00	225.0	1189.00	2183.80	2.54	1310.15
807.80	203.3	1193.00	2184.20	2.41	1310.21
999.00	184.2	1198.00	2184.60	2.44	1310.21
1197.60	166.71	1199.39	2185.00	2.30	1310.26
1298.00	174.07	1199.17	2185.20	2.34	1310.27
1500.20	171.8	1202.00	2185.60	2.32	1310.29
1800.00	168.08	1203.17	2185.80	2.18	1310.32
1810.60	158.11	1208.58	2186.00	2.22	1310.31
1821.20	152.76	1210.95	2186.40	2.21	1310.34
1906.00	131.93	1226.97	2186.60	2.06	1310.38
1927.20	122.76	1234.09	2186.80	2.10	1310.38
1948.40	109.78	1243.71	2187.20	2.09	1310.39
1969.60	92.68	1255.60	2187.40	1.93	1310.44
1992.40	71.73	1269.33	2187.60	1.98	1310.44
2012.00	52.39	1280.61	2188.00	1.96	1310.46
2022.60	44.04	1285.26	2188.20	1.78	1310.52
2033.20	36.98	1289.00	2188.40	1.83	1310.51
2043.80	31.14	1292.16	2188.60	1.83	1310.52
2054.40	26.14	1294.92	2188.80	1.66	1310.57
2065.00	22.00	1297.16	2189.00	1.71	1310.56
2075.60	18.60	1299.12	2189.20	1.70	1310.58
2086.20	15.64	1300.88	2189.40	1.48	1310.64
2096.80	13.19	1302.39	2189.60	1.5 6	1310.62
2112.20	10.33	1304.21	2189.80	1.54	1310.64
2128.60	7.95	1305.93	2190.00	.00	.00
2139.20	6.69	1306.85	2200.00	.00	.00

6.6 RADIOLOGICAL CONSEQUENCES

The Alternative Source Term radiological consequence analyses were performed with inputs relating to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). FPL Energy Seabrook letter NYN-03061 transmitted License Amendment Request (LAR) 03-02, "Implementation of Alternative Source Term" to the Nuclear Regulatory Commission on October 6, 2003 for Docket No. 50-443.

This section presents the radiological assessment of postulated accidents. The consequences of these accidents have been compared to the acceptance criteria for acceptability. The Alternative Source Term methodology as established in Regulatory Guide 1.183 has been used to calculate the offsite and control room radiological consequences for Seabrook Station.

The following limiting Seabrook Station UFSAR Chapter 15 accidents are analyzed and presented in LAR 03-02:

- Loss of Coolant Accident
- Fuel Handling Accident
- Main Steam Line Break
- Steam Generator Tube Rupture
- Reactor Coolant Pump Shaft Seizure
- Rod Cluster Control Assembly Ejection
- Failure of Small Lines Carrying Primary Coolant Outside Containment (Letdown Line Break)
- Radioactive Gaseous Waste System Leak or Failure, and
- Radioactive Liquid Waste System Leak or Failure (release to atmosphere).

The results of these analyses show that the calculated total effective dose equivalent at the exclusion area boundary, at the low population zone outer boundary and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and General Design Criteria 19, as well as applicable acceptance criteria denoted in SRP-15.0.1. Thus, the radiological doses are acceptable with respect to the radiological consequences of design basis accidents.

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SEABROOK STATION

SECTION 7.0

NUCLEAR FUEL

7.0 NUCLEAR FUEL

This section summarizes the analyses performed in support of the SPU in the nuclear fuel and fuel-related areas. The results and conclusions of the analyses are provided in each of the following subsections:

- Thermal-Hydraulic Design
- Core Design
- Fuel Rod Design and Performance

The fuel assembly structural evaluation is provided in LAR Section 5.3.

7.1 THERMAL HYDRAULIC DESIGN

7.1.1 INTRODUCTION AND BACKGROUND

This section describes the thermal and hydraulics safety analysis and evaluations performed to support operation of the Seabrook Station core consisting of 17x17 robust fuel assemblies with intermediate flow mixers grids at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

7.1.2 INPUT PARAMETERS

LAR Table 7.1-1 summarizes the thermal-hydraulic design parameters used in the departure from nuclear boiling ratio analyses.

7.1.3 DESIGN BASIS AND METHODOLOGY

The thermal and hydraulic safety departure from nuclear boiling analyses performed for the SPU are based on the Revised Thermal Design Procedure methodology [Reference 7.1-1] and the WRB-2M DNB correlation [Reference 7.1-2]. The Standard Thermal Design Procedure methodology and the WRB-2 [Reference 7.1-3] or W-3 DNB correlation were used when Revised Thermal Design Procedure and WRB-2M were not applicable. The analyses demonstrate that the 95/95 departure from nuclear boiling design basis is met for the core in operation at the maximum analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

7.1.4 DESCRIPTION OF ANALYSES AND EVALUATIONS

7.1.4.1 CALCULATION METHODS

The Westinghouse version of the VIPRE-01 (VIPRE) code is used for departure from nuclear boiling ratio calculations with the WRB-2, WRB-2M and the W-3 DNB correlations. The use of VIPRE for the SPU analysis is in full compliance with the conditions specified in the Nuclear Regulatory Commission Safety Evaluation Report in WCAP-14565-P-A [Reference 7.1-4].

With the Revised Thermal Design Procedure methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and departure from nuclear boiling correlation predictions are considered statistically to obtain departure from nuclear boiling sensitivity factors. Based on the departure from nuclear boiling sensitivity factors, Revised Thermal Design Procedure design limit departure from nuclear boiling ratio values were determined such that there is at least a 95% probability at a 95% confidence level that departure from nuclear boiling will not occur on the most limiting fuel rod during normal operation, operational transients, or transient conditions arising from faults of moderate frequency (Condition I and II events as defined by the American Nuclear Society).

Uncertainties in plant operating parameters (pressurizer pressure, primary coolant temperature, reactor power, and Reactor Coolant System flow) are considered in the Revised Thermal Design Procedure departure from nuclear boiling ratio analysis. Only the random portion of each plant operating parameter uncertainty is included in the statistical combination for Revised Thermal Design Procedure. Adverse instrumentation bias is treated either as a direct departure from nuclear boiling ratio penalty or a direct analysis input.

In addition to the above considerations for uncertainties, departure from nuclear boiling ratio margin was obtained by performing the safety analyses to departure from nuclear boiling ratio limits higher than the design limit departure from nuclear boiling ratio values. Sufficient departure from nuclear boiling ratio margin was conservatively maintained in the safety analysis departure from nuclear boiling ratio limits to offset the rod bow, plant instrumentation bias, and Reactor Coolant System (lower plenum) flow anomaly departure from nuclear boiling ratio penalties. The net remaining departure from nuclear boiling ratio margin, after consideration of these penalties, is available for operating and design flexibility.

The Standard Thermal Design Procedure is used for those analyses where Revised Thermal Design Procedure is not applicable. The departure from nuclear boiling ratio limit for Standard Thermal Design Procedure is the appropriate departure from nuclear boiling correlation limit increased by sufficient margin to offset the applicable departure from nuclear boiling ratio penalties.

7.1.4.2 DNB PERFORMANCE

To support the operation at SPU conditions, departure from nuclear boiling ratio reanalyses were required to define new Core Limits, Axial Offset Limits (Advanced Setpoints), and American Nuclear Society Condition II and IV (locked rotor) accident acceptability. The accident departure from nuclear boiling analyses to support the SPU are addressed below.

7.1.4.2.1 LOSS OF FLOW

The departure from nucleate boiling analysis of the Loss of Flow accident was performed. Three cases, partial loss of flow, complete loss of flow, and reactor coolant pump under frequency, were analyzed using Revised Thermal Design

Procedure methodology. The under frequency case resulted in the lowest minimum departure from nucleate boiling ratio. The minimum departure from nucleate boiling ratios calculated for each of the three cases were greater than the safety analysis limit. Thus the departure from nucleate boiling design basis was met.

7.1.4.2.2 LOCKED ROTOR

The analysis of the locked rotor rods in departure from nucleate boiling accident was performed using Revised Thermal Design Procedure methodology. The locked rotor accident is classified as an American Nuclear Society Condition IV event. To calculate the radiation release as a consequence of the accident, departure from nucleate boiling calculations were performed to calculate the number of rods that would experience departure from nucleate boiling and be conservatively assumed to fail. The acceptance criteria for this analysis is demonstration that less than 10% of fuel rods experience departure from nucleate boiling. The analysis confirmed that less than 10% of the fuel rods are predicted to be in departure from nucleate boiling thereby meeting the less than 10% rods in departure from nucleate boiling acceptance criteria.

7.1.4.2.3 FEEDWATER MALFUNCTION

The feedwater malfunction event was bounded by the hot zero power steamline break case.

7.1.4.2.4 DROPPED ROD

Dropped rod limit lines were calculated using Revised Thermal Design Procedure methodology to address the acceptability of the plant's response to this accident. These limit lines are the loci of points which would result in the safety analysis limit departure from nucleate boiling ratio being reached, based on a wide span of core conditions (inlet temperature, power, and pressure).

There is no explicit departure from nucleate boiling ratio calculation for the dropped rod event. Calculation of the effects of the accident on the cycle specific core conditions is checked by the nuclear designer each cycle using these limit lines. This demonstrates that the departure from nucleate boiling design basis is met.

7.1.4.2.5 STATIC ROD MISALIGNMENT

The allowable $F_{\Delta H}$ limit for rod control cluster assembly misalignment was calculated using the Revised Thermal Design Procedure methodology. This is the value of $F_{\Delta H}$ at normal operating conditions that gives a minimum departure from nucleate boiling ratio equal to the Revised Thermal Design Procedure safety analysis departure from nucleate boiling ratio limits. The acceptability of this limit is determined by the nuclear designer each cycle.

7.1.4.2.6 STEAMLINE BREAK

The departure from nucleate boiling analysis of the hot zero power steamline break events was performed for the SPU conditions.

For the hot zero power cases, the mechanistic Standard Thermal Design Procedure and the W-3 departure from nucleate boiling correlations were applied. The W-3 departure from nucleate boiling ratio correlation limit for this transient is 1.45. The departure from nucleate boiling ratio limit is the correlation limit increased to account for departure from nucleate boiling penalties applicable at these conditions. The applicable penalty is the Reactor Coolant System flow anomaly which increases the departure from nucleate boiling ratio limit to 1.50. The analysis showed that the minimum departure from nucleate boiling ratio was greater than 1.50 thereby demonstrating that the departure from nucleate boiling ratio design basis was met.

7.1.4.2.7 ROD WITHDRAWAL FROM SUBCRITICAL

The departure from nucleate boiling analysis of the rod withdrawal from subcritical accident was performed for the SPU conditions. This transient results in a power excursion and a bottom-skewed power shape due to the withdrawal of the rod bank. A conservative generic power shape was applied. Two departure from nucleate boiling calculations are required for this accident. The W-3 correlation is applied for fuel assembly spans below the first mixing vane grid. The WRB-2 correlation is applied for fuel assembly spans above the mixing grid. Because of the zero power precondition of this event, the Revised Thermal Design Procedure methodology is not appropriate and so the mechanistic Standard Thermal Design Procedure was applied. For the Standard Thermal Design Procedure application, the departure from nucleate boiling ratio limits applied are the correlation limit departure from nucleate boiling ratios increased by the applicable departure from nucleate boiling ratio penalties. Since no penalties were applicable, the departure from nucleate boiling ratio limits were then 1.30 for the W-3 correlation and 1.17 for the WRB-2 correlation.

The results of the calculations showed that departure from nucleate boiling ratios remain above the respective departure from nucleate boiling ratio limits thereby demonstrating that the departure from nucleate boiling design basis is met.

7.1.4.3 FUEL TEMPERATURES AND ROD INTERNAL PRESSURES

The fuel temperatures and rod internal pressures for the SPU safety analysis were based on ZIRLO™ cladding design. The Nuclear Regulatory Commission approved Westinghouse PAD 4.0 fuel performance models [References 7.1-5 and 7.1-6] were used in the fuel temperature and rod internal pressure analyses. The integral fuel burnable absorber and non- integral fuel burnable absorber fuel temperatures and/or rod internal pressures were used as initial conditions for LOCA and non-LOCA transients. Also, based on the fuel temperature analysis, the linear power limit to preclude fuel centerline melting is determined to be 22.6 KW/ft at the analyzed power conditions.

7.1.5 ACCEPTANCE CRITERIA

The acceptance criteria are contained in each topic of LAR Subsection 7.1.4.2 (Departure from Nuclear Boiling Performance).

7.1.6 RESULTS /CONCLUSIONS

Core thermal-hydraulic analyses and evaluations performed in support of the Seabrook operation at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) showed that the core thermal-hydraulic design criteria are satisfied.

TABLE 7.1-1
THERMAL AND HYDRAULIC DESIGN PARAMETERS

Thermal and Hydraulic Design Parameters (using the Revised Thermal Design Procedure)	Design Parameters
Reactor core heat output, MWt	3659
Reactor core heat output, 10^6 BTU/hr	12,485
Heat generated in fuel, %	97.4
Core pressure, nominal, psia high flow low flow	 2270 2260
Pressurizer pressure, nominal, psia	2250
Radial power distribution(1)	1.587(1+0.3(1-P)) where P = Fraction of Full Power
Hot Full Power Nominal Coolant Conditions	
Vessel thermal design flow rate (including bypass) 10^6 lbm/hr GPM	 139.4 374,400
Core flow rate (excluding 8.3% bypass, based on thermal design flow) 10^6 lbm/hr GPM	 127.8 343,300
Core flow area, ft^2	51.08
Core inlet mass velocity, 10^6 lbm/hr-ft^2 (based on thermal design flow)	2.50
Thermal and Hydraulic Design Parameters (based on thermal design flow)	**Design Parameters**
Vessel/core inlet temperature, °F Vessel average temperature, °F Core average temperature, °F Core outlet temperature, °F Vessel outlet temperature, °F Average temperature rise in vessel, °F Average temperature rise in core, °F	556.8 589.1 593.8 626.5 621.4 64.6 68.8
Heat transfer Active heat transfer surface area, ft^2 Average heat flux, BTU/hr-ft^2 Average linear power, KW/ft Peak linear power for normal operation, KW/ft^2 Peak linear power for prevention of centerline melt, KW/ft	 59,700 203,600 5.84 14.6 22.6
Pressure drop across core, psi(3)	29.2

Notes:

(1) Revised Thermal Design Procedure analysis excludes the 4% measurement uncertainty that is included in these values.

(2) Based on Maximum F_Q of 2.50.

(3) Based on best estimate flow rate of 402,000 gpm

7.2 CORE DESIGN

7.2.1 INTRODUCTION AND SUMMARY

The nuclear design evaluation was performed considering an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). Standard nuclear design analytical models and methods [References 7.2-1, 7.2-2, and 7.2-3] accurately describe the neutronic behavior of the SPU core and were used to assess the impact of the uprate on key nuclear design parameters.

7.2.2 DESIGN BASIS

The specific design basis and its relation to the General Design Criteria in 10 CFR 50, Appendix A, for the SPU at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) are the same as those of the current licensed core power level of 3411 MWt.

7.2.3 METHODOLOGY

No changes to the Westinghouse nuclear design philosophy or methods are necessary because of the SPU. The nuclear design evaluation typically includes an evaluation of the key safety parameters that comprise the nuclear-design-dependent input to the safety analyses [Reference 7.2-1]. Examples of these parameters include power distributions, peaking factors, control rod worths, boron concentrations and reactivity coefficients. The key safety parameters are evaluated for each reload cycle. If one or more of the parameters fall outside the bounds assumed in the reference safety analysis, the affected transients are re-evaluated using standard methods and the results documented in the reload safety evaluation for that cycle.

7.2.4 DESIGN EVALUATION – PHYSICS CHARACTERISTICS AND KEY SAFETY PARAMETERS

Four cycles of core models were established that incorporated the SPU level. Conceptual loading patterns were developed based on projected energy requirements of approximately 500 to 550 effective full-power days per cycle. The loading patterns were developed to minimize the number of feed assemblies while meeting defined constraints on cycle energy, $F_{\Delta H}$, burnup, moderator temperature coefficient, and fuel enrichment. These loading patterns were used to confirm the continued validity of existing key safety parameters, or establish revised parameter limits where needed, to allow flexibility in designing actual reload cores. LAR Table 7.2-1 compares selected key parameters for the current and SPU conditions. The loading patterns were also used to calculate representative power distributions for confirming the acceptability of transient statepoint conditions, and fuel rod performance parameters, as well as establishing necessary power distribution inputs for the best estimate large break LOCA analysis

Westinghouse identified that SPU cycles with long cycle lengths and very large numbers of 120 inch integral fuel burnable absorber rods could potentially generate

peak steady-state and transient F_Q values in the bottom 15% of the core. The axial zone is currently excluded from the F_Q surveillance of Seabrook Station Technical Specification Surveillance Requirement 4.2.2.2.g. As a result, the F_Q surveillance exclusion zone is changed from 15% to 10%.

7.2.5 NUCLEAR DESIGN EVALUATION CONCLUSIONS

Key safety parameters were evaluated for conservative SPU core conditions (analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level)). Where necessary, the key parameters were revised to allow flexibility in designing actual reload cores. Representative power distributions were calculated for use in confirming fuel design limits at nominal and transient statepoint power conditions and for establishing normal operating power distribution ranges for the best estimate LOCA analysis. The behavior of the power distributions and peaking factors at the SPU power level will vary normally from loading pattern to loading pattern, as do typical non-SPU power variations. Typical methods and range of enrichment and burnable absorber variation will be employed in cores designed for the SPU condition to ensure compliance with the peaking factor and reactivity parameter Technical Specifications. Nuclear design criteria were met for the loading patterns generated at the SPU conditions. The specific reload cycle core design will be such that it meets the nuclear design criteria at the SPU conditions.

TABLE 7.2-1
SELECTED KEY NUCLEAR SAFETY PARAMETERS

SAFETY PARAMETERS	CURRENT VALUES	SPU VALUES
Reactor core power (MWt)	3411 (licensed)	3659 (analyzed)
Vessel T_{avg} hot full power (°F)	588.5	571.0 to 589.1
Reactor Coolant System pressure (psia)	2250	2250
Core average linear heat rate (KW/ft)	5.45	5.84
Most positive moderator temperature coefficient (pcm/°F)	+ 5.0 for ≤ 70% Rated Thermal Power +5.0 to 0.0 ramp from 70% to 100% Rated Thermal Power	+ 5.0 for ≤ 70% Rated Thermal Power +5.0 to 0.0 ramp from 70% to 100% Rated Thermal Power
Most positive moderator density coefficient (Δk/gm/cc)	0.50	0.54
Doppler temperature coefficient (pcm/°F)	-0.9 to -3.2	-0.9 to –3.2
Doppler only power coefficients (pcm/% Power) least negative (Hot zero power to 121% Rated Thermal Power overpower condition)	-5.32 to –9.55	-5.32 to –9.55
Doppler only power coefficients (pcm/% Power) most negative (Hot zero power to 121% Rated Thermal Power overpower condition)	-11.17 to -19.40	-11.17 to -19.40
Beta-effective	0.0044 to 0.0075	0.0044 to 0.0075
Shutdown margin (pcm)	1300	1300
Nuclear design $F_{\Delta H}$	1.60/1.65	1.65
Nuclear design F_Q	2.50	2.50

7.3 FUEL ROD DESIGN AND PERFORMANCE

7.3.1 INTRODUCTION

Fuel rod design analyses were performed to assess the potential impacts that the SPU operating conditions of Seabrook Station would have on meeting fuel rod design criteria.

7.3.2 DESCRIPTION OF ANALYSES, ACCEPTANCE CRITERIA, AND RESULTS

The fuel rod design analyses modeled 17x17 robust fuel assemblies, 6" annular blanket, 1.5X integral fuel burnable absorber, ZIRLO™ clad fuel rods irradiated for up to three cycles at SPU conditions.

The following sections summarize the impact of the core SPU on the fuel rod design criteria most affected by the SPU core power. The fuel rod design criteria considered rod internal pressure, clad corrosion, clad stress, and clad strain criteria. Other fuel rod design criteria are not significantly impacted by a core SPU.

7.3.2.1 ROD INTERNAL PRESSURE

Design Basis

The fuel system will not be damaged due to excessive fuel rod internal pressure.

Acceptance Limit

The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which could cause the diametral gap to increase due to outward clad creep during steady state operation or cause extensive departure from nucleate boiling propagation to occur.

Design Evaluation

The analyses performed showed that the SPU core power level impacts the rod internal pressure criterion. The higher power levels result in higher fuel operating temperatures with a potential for increased fission gas release. Analysis of the representative rod power histories indicated that the higher duty fuel rods have increased fission gas release resulting in higher rod internal pressures. The results of the analysis meet the acceptance criteria thereby demonstrating that the fuel system will not be damaged due to excessive fuel rod internal pressure at SPU conditions.

7.3.2.2 CLAD CORROSION

Design Basis

The fuel system will not be damaged due to excessive fuel clad oxidation. The fuel system will be operated to prevent significant degradation of mechanical properties of the clad at low temperatures, due to hydrogen embrittlement caused by formation of zirconium hydride platelets.

Acceptance Limit

The calculated fuel clad temperature (metal-oxide interface temperature) will be less than the license limit temperature for ZIRLO™ clad fuel during steady state operation. For American Nuclear Society Condition II events, the calculated fuel clad temperature will not exceed the license limit for ZIRLO™ clad fuel. The hydrogen pickup level in the fuel clad will be less than or equal to the license limit at the end of fuel operation.

Design Evaluation

The SPU conditions result in increased operating temperatures for the fuel clad due to the increased fuel rod average power rating. Since the corrosion process is a strong function of fuel clad temperature, the SPU will impact these criteria. Analysis of the representative rod power histories indicated that the corrosion design criteria is met for the higher duty fuel rods at the SPU core conditions.

7.3.2.3 CLAD STRESS AND STRAIN DESIGN BASIS

The fuel system will not be damaged due to excessive fuel clad stress and strain.

Acceptance Limit

The volume average effective stress calculated with the Von Mises equation, considering interference due to uniform cylindrical fuel pellet-clad contact, caused by fuel pellet thermal expansion, fuel pellet swelling, uniform fuel clad creep, and pressure differences, is less than the 0.2% offset yield stress with due consideration to temperature and irradiation effects under American Nuclear Society Condition II events. The acceptance limit for fuel rod clad strain during American Nuclear Society Condition II events is that the total tensile strain increase, due to uniform cylindrical fuel pellet thermal expansion during a transient, is less than 1% from the pre-transient value.

Design Evaluation

The Westinghouse PAD 4.0 fuel performance models [References 7.1-5 and 7.1-6] are used to evaluate fuel clad stress and strain limits. The local power duty during American Nuclear Society Condition II events is a key factor in evaluating the margin to fuel clad stress and strain limits. The fuel duty at the SPU conditions is more limiting, resulting in an increase in the cladding stress and strain levels. The transient limits were modified to meet the cladding stress criterion. The fuel analyses results show that the calculated fuel clad stress is less than the 0.2% offset yield stress and the fuel clad strain is less than the 1% pre-transient value thereby demonstrating that the SPU will not impact the fuel's capability to meet the clad stress and strain limits.

7.3.3 CYCLE SPECIFIC ANALYSES

The fuel rod design criteria most impacted by a change in core power rating have been evaluated. The evaluations indicate that the fuel rod design criteria can be met at the SPU core conditions with the proper cycle-specific core design.

Cycle-specific core designs and fuel performance analyses are performed for each reload cycle. These cycle-specific analyses are performed to ensure that the fuel rod design criteria will be satisfied for the specific operating conditions of that cycle.

Although the SPU analyses described in this section were performed for ZIRLO clad fuel, the cycle-specific fuel performance analyses consider each specific fuel region (whether ZIRLO clad fuel design or older fuel designs with different fuel features) in the core during that cycle. These analyses ensure that the fuel rod design criteria are met for each fuel region.

The cycle-specific fuel performance analyses will consider improved fuel performance models and methods licensed and approved by the NRC available at the time of the specific cycle design. These cycle-specific evaluations support the Reload Safety Evaluation performed for each cycle of operation.

7.3.3.1 CONCLUSIONS

The fuel rod design criteria most impacted by a change in core power rating have been analyzed. The analyses results indicate that the fuel rod design criteria are met at the SPU conditions. Fuel rod design criteria will be confirmed during the cycle-specific reload core design.

7.4 REFERENCES

7.1-1 Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, April 1989.

7.1-2 L. D. Smith, et al., "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids,"WCAP-15025-P-A, April 1999.

7.1-3 Letter from H. A. Sepp (Westinghouse) to T. E. Collins (NRC), "Notification of FCEP Application for WRB-1 and WRB-2 Applicability to the 17x17 Modified LPD Grid Design for Robust Fuel Assembly Application," NSD-NRC-98-5618, March 25, 1998.

7.1-4 Sung. Y. et al., WCAP-14565-P-A/WCAP-15306-NP-A. "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis." October 1999.

7.1-5 Slagle, W. H. (Ed.), "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Rev. 1 w/ errata July 2000.

7.1-6 Davidson, S. L., Ryan, T. L., "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A, April 1995.

7.2-1 WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," S. L. Davidson, (Ed.), et al., July 1985.

7.2-2 WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," T. Q. Nguyen, et al., June 1988.

7.2-3 WCAP-10965-P-A, "ANC: A Westinghouse Advanced Nodal Computer Code," Y. S. Liu, et al., September 1986.

SEABROOK STATION

SECTION 8.0

BALANCE OF PLANT

8.0 BALANCE OF PLANT (BOP)

A detailed BOP review was performed to determine the plant system and component impacts related to increasing the licensed thermal power from 3411 MWt to 3587 MWt. The BOP evaluations and analyses were coordinated with the Nuclear Steam Supply System (NSSS) system and component evaluations.

8.1 INPUTS

8.1.1 SYSTEM AND COMPONENT INTERFACE

Information required to perform the system evaluations was obtained from various sources. In general, system and component design information was obtained from existing Seabrook Station documentation (including drawings, calculations, modification records, etc.). For many systems, NSSS SPU operating information was required to support BOP evaluations. In these cases, system and component interface information requirements were developed and the required information was transferred from the NSSS vendor (Westinghouse) to the BOP vendor (Stone & Webster) to support the SPU evaluations. This information included:

- Mass and energy release information for loss of coolant accident and main steam line break evaluations,
- Main steam safety, atmospheric relief, isolation, and dump valve requirements,
- Feedwater system required flow rates and isolation and control valve requirements,
- Various system heat loads and cooldown capabilities, and
- Various other NSSS information.

Additionally, some interface information was required from the turbine vendor (General Electric Energy Services) to support the BOP evaluations. The information requirements were established and the provided information (including heat balances, LAR Subsection 8.2.1) was used to support the SPU evaluations as Quality Assurance verified inputs.

8.2 HEAT BALANCES

Many of the BOP input parameters used for the Seabrook Station SPU evaluations are based on BOP heat balances. The heat balances (listed in LAR Subsection 8.2.1) were developed for current and several SPU conditions. The BOP secondary plant system and component parameters were developed from the heat balance mass flow, temperatures, and steam system pressures. Based on these inputs, system calculations and evaluations were prepared to determine the impact of the SPU on BOP systems.

8.2.1 HEAT BALANCE DETAILS

Several heat balances were developed to determine the impact of the increase in NSSS thermal power. Heat balances were developed for the current power level and bounding SPU core power levels with various input assumptions used to model specific system inputs. In most cases the SPU evaluations (unless otherwise noted) were prepared utilizing a bounding analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The various heat balances are listed / summarized, below:

- Current Heat Balance Case, current "baseline" tuned model. Based on a current NSSS power level of 3428.5 MWt. (Included in this power level is heat added by the reactor coolant pumps and heat loss to the Chemical and Volume Control System). This thermal output / heat balance corresponds to the current licensed core power of 3411 MWt. This heat balance is used to estimate current system parameters. This model was developed by "tuning" the current station heat balance computer model to match actual plant performance based on measured operating conditions. This model formed the basis for developing the increased power heat balances.
- SPU Heat Balance Case , Reactor power is equal to Analyzed NSSS Thermal Power Level of 3678 MWt. Circulating Water temperature (and therefore condenser backpressure) set for the "best efficiency point" (approximately 2.0 in Hg).

In support of the SPU and the high pressure turbine modifications, General Electric Energy Services (GEES) has prepared several heat balances. In general, these represent design conditions for the modified high pressure turbine and were not used as part of the BOP system evaluations. Turbine performance criteria from the GE heat balances were incorporated into the SPU heat balances. (See heat balance Model Tuning, LAR Subsection 8.2.2).

For some specific evaluations it was useful to compare conditions with current design heat balance information. For these conditions, Seabrook Station UFSAR figures were used. Specifically:

- UFSAR Figure 10.1-1, Heat Balance, 100% Load, 9763-F-202116
- UFSAR Figure 10.1-2, Heat Balance, Valves Wide Open, 9763-F-202115

8.2.2 HEAT BALANCE MODEL TUNING

These heat balances were developed from the current heat balance model of Seabrook Station. This model was "tuned" to match actual measured plant operating conditions in order to generate a model that would represent current plant operating conditions. This tuned model is documented as the Current Heat Balance Case described above. Because of this tuning to match actual measured plant operating conditions, the heat balance model better predicts SPU operating conditions. Because there are differences between design and actual operating conditions, the use of the "tuned" computer models for making parameter change comparisons between current and expected SPU conditions ensures that the BOP system evaluations will be based on the best available information. For some specific analyses, design information was required. In those specific cases, design condition heat balances were used.

8.2.3 SPU HEAT BALANCE MODIFICATIONS

Implementation of the SPU will require several modifications to BOP equipment. The "tuned" heat balance computer model was modified to account for these plant modifications in the predictions of SPU operating conditions. As part of the SPU a new high pressure turbine steam path and new moisture separator and reheater sections will be installed. Therefore, the heat balances were modified to incorporate the new equipment design information.

The high pressure turbine will be modified by the existing turbine vendor (General Electric Energy Services) based on their advanced design steam path high pressure turbine. General Electric supplied information, included in the heat balances described above, was used as input for the modifications to the "tuned" SPU heat balance model to ensure that the BOP heat balances would represent the expected performance of the modified high pressure turbine.

The moisture separator / reheaters are being modified to improve the moisture removal ability of the moisture separator section and the thermal performance of the reheater. The "tuned" heat balance model was modified to include the performance improvements that result from these component modifications as predicted by Thermal Engineering International, the moisture separator / reheater modification vendor.

TABLE 8.2-1
SPU SYSTEM PARAMETER CHANGES

System(s) / Parameter(s)	Current	SPU
LAR Section 8.2 - Heat Balance Parameters		
Heat Balance Parameters		
NSSS power level (MWt) (Note 1)	3428.5	3678 (analyzed)
Steam generator pressure (psia) (Note 1)	1002.4	1000
Total steam flow rate (lbm/hr) (Note 1)	15,140,000	16,390,000
LAR Subsection 8.4.1 - Main Steam System		
Steam Dump (LAR Section 4.2)		
Capacity (lbm/hr), per valve, 12 valves	510,000	No Change
Percent of main steam flow (%)	>40%	Acceptable, LAR Section 4.2
Main Steam Safety Valves (LAR Section 4.2)		
Total capacity (lbm/hr)	18.161×10^6	No Change
Percent of main steam flow (%) (105% required)	>105%	109.8%
Set pressures (psia)	1185, 1195, 1205, 1215, 1225	No Change
Main Steam Atmospheric Steam Dump Valves (LAR Section 4.2)		
Total capacity (lbm/hr)	2,047,000 at 1106.4 psia	No Change
Percent of main steam flow (%) (LAR Subsection 4.2.3.1.2)	Approximately 10%	Approximately 10%
Set pressures (psia)	1120	No Change
Main Steam Header – Steam Generator Outlet		
Flow rate (lbm/hr) (approximate)	15,140,000	16,390,000
Operating pressure (1200 psig design rating)	1002.4	1000
Operating temperature (°F) (600°F design rating)	544.9	544.6
Quality (%)	99.9	99.8
Flow velocity (fps)	118	124

Note 1. Values may differ from values shown in LAR Table 2.3-1. Balance of Plant parameters utilized for system and component evaluations were based on "best estimate" values at an analyzed SPU Core Power Level of 3659 MWt (3678 MWt NSSS Power Level). The range of values in LAR Table 2.3-1 are utilized for Accident Analysis.

TABLE 8.2-1 (continued)
SPU SYSTEM PARAMETER CHANGES

System(s) / Parameter(s)	Current	SPU
LAR Subsection 8.4.2 – Extraction Steam System		
Feedwater Heater Number 21		
Pressure operating (psig)	9.3	9.9
Pressure design (psig)	Full vacuum to 50 psig	
Total flow rate (lbm/hr)	841,400	871,000
Quality (%)	85.3	86.9
Flow velocity (fps)	180	179
Feedwater Heater Number 22		
Pressure operating (psig)	19.4	20.6
Pressure design (psig)	Full vacuum to 50 psig	
Total flow rate (lbm/hr)	442,000	466,400
Quality (%)	91.1	92.6
Flow velocity (fps)	204	206
Feedwater Heater Number 23		
Pressure operating (psig)	62	66.7
Pressure design (psig)	Full vacuum to 100 psig	
Total flow rate (lbm/hr)	702,100	752,400
Quality (%)	100	100
Flow velocity (fps)	173	178
Feedwater Heater Number 24		
Pressure operating (psig)	101.8	109.8
Pressure design (psig)	Full vacuum to 150 psig	
Total flow rate (lbm/hr)	383,200	410,200
Quality (%)	100	100
Flow velocity (fps)	114	118
Feedwater Heater Number 25		
Pressure operating (psig)	171.1	183.1
Pressure design (psig)	300	
Total flow rate (lbm/hr)	555,300	599,400
Quality (%)	86.8	86.5
Flow velocity (fps)	148	149

TABLE 8.2-1 (continued)
SPU SYSTEM PARAMETER CHANGES

System(s) / Parameter(s)	Current	SPU
LAR Subsection 8.4.2 – Extraction Steam System (continued)		
Feedwater Heater Number 26		
Pressure operating (psig	428.4	467.2
Pressure design (psig)	500	
Total flow rate (lbm/hr)	1,020,700	1,367,300
Quality (%)	91.5	91.7
Flow velocity (fps)	119	150
LAR Subsection 8.4.3 – Condensate and Feedwater Systems		
Condensate Pumps		
Total flow (gpm)	21,250	22,600
Total developed head (ft)	936	1035
Brake horsepower (bhp)	3,110	3,410
(Condensate pump impeller and bowl to be modified for SPU, which will increase discharge pressure approximately 43 psi. This increase is to allow the feedwater pump turbine speed to remain unchanged.)		
Steam Generator Feedwater Pumps		
Total flow (gpm)	35,150	37,400
Total developed head (ft) (approximate)	2402	2284
Brake horsepower (bhp)	10,575	10,825
Speed (rpm) (approximate)	5,300	No Change
(Condensate pump impeller and bowl to be modified for SPU, which will increase discharge pressure approximately 43 psi. This increase is to allow the feedwater pump turbine speed to remain unchanged.)		
Feedwater Regulating Valve		
Valve positions (%)	≤ 80	≤ 82
Final Feedwater to Steam Generators		
Total flow (lbm/hr) (approximate)	15,230,000	16,480,000
Final temperature (°F)	441.6	447.1
Tube Side Velocity (fps)		
Feedwater heater number 21	7.2	7.7
Feedwater heater number 22	7.9	8.4
Feedwater heater number 23	7.9	8.4
Feedwater heater number 24	8.4	9.0
Feedwater heater number 25	8.7	9.3
Feedwater heater number 26	7.5	8.2

TABLE 8.2-1 (continued)
SPU SYSTEM PARAMETER CHANGES

System(s) / Parameter(s)	Current	SPU
LAR Section 8.4.4 - Emergency Feedwater System		
Flow Requirements – Faults of Moderate Frequency		
Minimum flow rate delivered to four intact steam generators by one pump (gpm)	650	No Change
Minimum flow rate delivered to three intact steam generators by two pumps (gpm)	650	No Change
Flow Requirements – Infrequent and Limiting Faults		
Minimum flow rate delivered to three intact steam generators by one pump (gpm)	470	No Change
Minimum flow rate delivered to two intact steam generators by two pumps (gpm)	470	No Change
Maximum Flow Rate Delivered		
Main steam line break within containment (gpm) (Two pumps to three intact steam generators)	1550	No Change
Minimum usable condensate storage tank inventory (gal.)	196,000	No Change
LAR Subsection 8.4.5 - Steam Generator Blowdown System		
Normal blowdown rate per steam generator (lbm/hr)	89,000	No Change
LAR Subsection 8.4.6 - Main Condenser Evacuation and Water Box Priming Systems		
Minimum shell side evacuation system capacity (scfm)	45 at 1 in HgA and 71.5°F	No Change
Required water box priming system total capacity (scfm)	138 at 22 in HgV (design)	137.8 at 16.5 in HgV
LAR Subsection 8.4.7 - Main Condenser and Circulating Water System		
Main Condensers		
Condenser vacuum at maximum ocean temperature (≈ 65°F) (in. HgA)	2.41	2.62
Condenser temperature differential – 3 circulating water pumps operating (°F)	32.0	34.2
Condenser temperature differential – 2 circulating water pumps operating (°F)	41.6	44.5
Circulating Water Pump		
Total flow – 3 circulating water pumps operating (gpm)	470,600	No Change
Total flow – 2 circulating water pumps operating (gpm)	362,000	No Change

TABLE 8.2-1 (continued)
SPU SYSTEM PARAMETER CHANGES

System(s) / Parameter(s)	Current	SPU
LAR Subsection 8.4.8 – Heater Drains		
Feedwater Heater Number 21		
Total flow rate (lbm/hr)	789,600	818,300
Maximum normal level control valve position (%)	50	52
Feedwater Heater Number 22		
Total flow rate (lbm/hr)	509,100	540,500
Maximum normal level control valve position (%)	55	57
Feedwater Heater Number 23		
Total flow rate (lbm/hr)	361,800	387,500
Maximum normal level control valve position (%)	80	83
Feedwater Heater Number 24		
Total flow rate (lbm/hr)	127,700	136,700
Maximum normal level control valve position (%)	45	46
Feedwater Heater Number 25		
Total flow rate (lbm/hr)	1,686,600	1,766,900
Maximum normal level control valve position (%)	N/A	N/A
Feedwater Heater Number 26		
Total flow rate (lbm/hr)	1,409,000	1,467,200
Maximum normal level control valve position (%)	45	45
Heater Drains Pumps		
Total flow (gpm)	10,475	11,960
Total developed head (ft) (approximate)	810	683
Brake horsepower (bhp)	1,136	1,103
Drains From Moisture Separator		
Total flow rate (lbm/hr) (approximate)	1,241,165	1,694,630
Maximum normal level control valve position (%)	50	44
LAR Subsection 8.4.9 - Spent Fuel Pool Cooling		
Maximum pool heat load (10^6 Btu/hr)	47.791	56.544
Pool time to boil with maximum pool heat load (hrs.)	3.28	3.13
Minimum allowable service water (i.e., ocean) temperature (°F)	62.9	59.3
Full core offload time to achieve design basis heat load (46.442 x 10^6 Btu/hr) (hrs.)	118.5	133.8

TABLE 8.2-1 (continued)
SPU SYSTEM PARAMETER CHANGES

LAR Subsection 8.4.10 – Containment Spray System
The Containment Spray System analysis demonstrated that the mass and energy releases for LOCA (LAR Subsection 6.4.1.1) and main steam line breaks (LAR Subsection 6.4.4.1) at SPU conditions result in peak containment pressures and temperatures that are bounded by the current peak pressures and temperatures. Containment Building Spray System pump net positive suction head and heat exchanger heat removal capability are acceptable for the SPU.
LAR Subsection 8.4.11 - Ultimate Heat Sink
Refer to LAR Subsection 8.4.12, Service Water System
LAR Subsection 8.4.12 - Service Water System
Refer to LAR Tables 8.4.12-1 and 8.4.12-2.
LAR Subsection 8.4.13 - Primary and Secondary Component Cooling Water Systems
Primary Component Cooling Water System
Refer to LAR Tables 8.4.13.1-1 and 8.4.13.1-2
Secondary Component Cooling – Normal Operation
Total heat load is bounded by system design; no flow rate changes.

8.3 TURBINE GENERATOR AND TURBINE AUXILIARY SYSTEMS

The turbine-generator and auxiliary systems have been reviewed at the SPU conditions. The review included a structural analysis. These evaluations were based on heat balance input parameters, such as steam generator outlet conditions, feedwater heater performance, and condenser pressure. Heat balance calculations were used to determine performance of the turbine generator as well as operating conditions for analysis of the capability of the various components.

8.3.1 TURBINE

This review concluded that modification to the high pressure turbine steam path would be required to accommodate the SPU. No other changes to the main turbine were required for operation at the SPU conditions. The modified steam path will be designed for a valves wide open capability of 3719.6 MWt. The high pressure turbine stage 1 nozzle plates, high pressure diaphragms and buckets will be replaced with new, high efficiency components.

Other turbine component analyses included:

- Low pressure turbine rotors and buckets, including last stage
- Low pressure diaphragms
- Shells, casings and associated bolting
- Main steam leads and crossover piping
- Moisture separator-reheater vessel for adequacy at increased operating pressure
- Main stop and control valves
- Combined reheat valves
- Rotor couplings
- Rotor dynamics, stability, and torsional stresses
- Thrust loads and potential thrust imbalances
- Journal bearing loads and temperatures
- Overspeed sensitivity and protection (turbine missiles)

8.3.2 GENERATOR

The main electric generator was analyzed at SPU conditions. The generator review included the following components:

- Stator winding
- Stator core
- Rotor shaft

- Field winding
- High voltage bushings
- Current transformers
- Hydrogen gas cooling system
- Stator cooling water system
- ALTERREX excitation system

The predicted generator output falls within the current generator capability, therefore, no changes are required for operation at the SPU conditions. Generator capability is governed by the existing reactive capability curve.

8.3.3 TURBINE AUXILIARIES

Turbine auxiliary systems, including steam seals, and turbine lube oil, have been reviewed and found to be acceptable for operation at the SPU conditions.

8.3.4 CONCLUSION

In summary, the turbine-generator has been evaluated at SPU conditions assuming installation of the new high pressure steam path. The main turbine, generator, and associated auxiliaries have been found to be acceptable for operation at increased thermal power. In addition, the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of turbine generated missiles and will continue to meet the requirements of General Design Criteria 4 following implementation of the SPU.

8.4 SYSTEM ASSESSMENTS

8.4.1 MAIN STEAM

8.4.1.1 DESCRIPTION

The evaluation of the Main Steam System demonstrated that the current design of the system is acceptable to support SPU operation.

The Main Steam System transports saturated steam from the steam generators to the high pressure turbine. The main steam system is described in the Seabrook Station UFSAR Sections 10.1, 10.3, and portions of 10.4. The Main Steam System has both safety and non-safety related functions. The original turbine supplier (General Electric Engineering Services) evaluated the Seabrook Station turbine. As part of the SPU, a modified high pressure turbine will be installed to support the SPU steam conditions. This evaluation is contained in LAR Section 8.3.

The Main Steam System design functions are:

- Conduct steam from the steam generators to the main turbine, feed pump turbine drives, emergency feed pump turbine drive, reheaters, turbine gland sealing system, Steam Dump System and the Auxiliary Steam System,
- Control steam generator pressure during startup and shutdown and while the condenser is not available,
- Provide over-pressure protection for the steam generators,
- Isolate the Containment from the Main Steam Supply System and provide for main steam line warm-up,
- Provide a means to dissipate the heat generated in the Nuclear Steam Supply System, during normal operation and following a turbine trip at full load.

The portions of the Main Steam System from the steam generators up to and including in the main steam isolation valves, the atmospheric steam dump valves, and the main steam safety valves are designed as safety-related. The Main Steam supply to the turbine driven emergency feedwater pump and turbine drive exhaust piping is also safety-related.

The main steam safety, steam dump, and isolation valve performance capability is evaluated as documented in LAR Section 4.2.

8.4.1.2 EVALUATION

The Main Steam System components were evaluated to ensure they are capable of performing their intended functions at SPU conditions thereby ensuring the functionality of the Main Steam System at SPU conditions. Main Steam System conditions were conservatively evaluated for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The evaluations compared design

parameters of the Main Steam System components with SPU conditions to ensure margin exists. Specifically:

- The Main Steam System piping was evaluated for expected SPU pressure, temperature, and flow conditions. Pressure drops through the Main Steam System piping at SPU conditions were calculated. The calculated pressure drops were utilized to determine turbine capacity and throttle inlet conditions. The Main Steam drain system was also evaluated for SPU conditions.
- The main steam isolation valves, main steam safety valves, atmospheric steam dump valves, and steam dump valves were evaluated to ensure they are capable of performing their design functions at SPU conditions.

8.4.1.2.1 SYSTEM OPERATING CONDITIONS

The steam generator outlet conditions used for the BOP evaluations are listed below:

	CURRENT	SPU
Flow rate, lbm/hr	15,140,000	16,390,000
Pressure, psia	1002.4	1000
Temperature, °F	544.9	544.6
Quality, %	99.9%	99.8%

The Main Steam System design pressure of 1185 psig (1200 psia) bounds the SPU operating conditions of approximately 1000 psia. Additionally, the highest normal operating pressures and temperatures occur at no load conditions. These conditions are not affected by the SPU.

Pressure drops and flow velocities through the Main Steam piping from the steam generators to the turbine control and stop valves were calculated at current and SPU conditions. The flow velocities increase approximately 5% from current and remain below plant and industry design limits.

8.4.1.2.2 COMPONENT DESIGN EVALUATIONS

Main Steam Safety Valves

The main steam safety valves and atmospheric steam dump valves are acceptable for SPU conditions without modification as demonstrated in LAR Section 4.2. The valve design conditions (pressure/temperature) remain bounding for the SPU conditions. The valve setpoints and required flow capacity do not change for SPU conditions. Analysis has determined that the setpoints and flow capacity is adequate to support SPU operation including loss of load transients. Refer to LAR Section 4.2 for details of these evaluations.

Main Steam Isolation Valves

The SPU design conditions for the main steam isolation valves are bounded by the original design conditions. Required valve closing time is not affected by the SPU. For current and SPU operation, the conditions that result in the highest flow through the valves and requiring valve operation is a main steam line break. A main steam line break from hot standby conditions results in the highest flow rates (compared to breaks at other power levels) for current and SPU conditions. Based on analysis performed to support the SPU, a negligible decrease in break flow is predicted. Therefore, main steam isolation valve flow conditions for a main steam line break will remain similar to current conditions.

Steam Dump (Turbine Bypass)

The design of the steam dump valves is adequate to support SPU operating conditions. The existing Steam Dump (Turbine Bypass) System has adequate capacity to support the SPU conditions. The capacity of the Steam Dump System (in lbs/hr) is not affected by the SPU; however, the capacity as a percentage of steam flow will be reduced. Analysis has shown that load rejection capability is maintained with the lower percentage flow. Refer to LAR Section 4.2 for details on this evaluation. As the Steam Dump System flow conditions do not change, there is no change from current for a malfunction of the Steam Dump System to adversely affect essential systems or components. The SPU does not affect the ability of the Steam Dump System to perform its functions, including support for plant shutdowns, during normal operations.

Moisture Separator/Reheaters

The moisture separators/reheaters are being modified to improve performance and support the SPU steam conditions. The modifications were planned for SPU conditions to ensure acceptable operation at SPU conditions. Because of the higher high pressure turbine exhaust conditions (pressure and flow), modification to the moisture separators relief valve setpoints will be required to provide an acceptable margin above operating pressure.

Emergency Feedwater Pump Turbine Supply

The emergency feedwater pump turbine supply and exhaust piping were determined to be acceptable for SPU conditions. The pressure ratings remain bounding of operating conditions. Flow conditions are not affected by the SPU as the emergency feedwater flow rate does not change for the SPU (refer to LAR Subsection 8.4.4).

Main Steam Supply to Auxiliary Steam

Main Steam flow required to support Auxiliary Steam loads is not affected by the SPU. Auxiliary steam loads are small in terms of total Main Steam flow, and are not changed by the implementation of the SPU. The operation of the Auxiliary Steam System and its ability to perform its function, is not affected by the SPU.

Main Steam Drains

The main steam drains are not impacted by the SPU. The SPU does not significantly affect the operating drainage requirements (such as pipe diameter, insulation thickness, steam temperature). The SPU will not affect start up drainage requirements.

Instrumentation

Main Steam pressure and flow instruments will still conform to Regulatory Guide 1.97 requirements at SPU conditions. No significant changes will occur to the Main Steam System pressure; therefore, there is no impact on the Main Steam pressure instrumentation. Main Steam flow will increase, but will remain within the design capability of the Main Steam flow instrumentation (refer to LAR Subsection 8.4.17). Therefore, the flow instrumentation is not affected by the SPU. The steam generator water level settings and control bands are not affected by the SPU (refer to LAR Section 5.7). Therefore, the level instruments are not affected by the SPU. The Main Steam flow and pressure instrumentation and the steam generator level instrumentation are not affected by the SPU and will continue to conform to Regulatory Guide 1.97 requirements.

8.4.1.2.3 GENERAL DESIGN CRITERIA

The design of the Main Steam System should be in accordance with General Design Criteria 2, 4, 5, and 34.

- General Design Criteria 2 is related to the safety-related portions of the system being capable of withstanding the effects of various natural phenomena. The SPU will not affect these natural phenomena or the plant design to account for these phenomena.
- General Design Criteria 4 is addressed in the evaluations contained in LAR Section 8.5.
- The SPU does not affect the capability of the Main Steam System to meet the required safety functions for shared systems and components (General Design Criteria 5).
- With regard to General Design Criteria 34, the Main Steam System will continue to be able to function to transfer residual and sensible heat from the reactor systems. Refer to LAR Section 4.2 for additional discussion.

8.4.1.3 CONCLUSION

The steam pressure and temperatures associated with the SPU are bounded by the design of the Main Steam System and its components with margin.

The Main Steam flow velocities and pressure drops at SPU conditions remain acceptable.

The main steam safety valves and atmospheric steam dump valves design conditions, capacity, and setpoints are adequate for SPU operation. The main

steam isolation valves are acceptable for SPU flow conditions and the closing times do not change. The Steam Dump System valves will support SPU operation (Refer to LAR Section 4.2).

The Main Steam System will continue to maintain its ability to transport steam to the power conversion system, provide heat sink capacity, a pressure relief capability, supply steam to steam-driven emergency feedwater pumps, and withstand steam hammer (refer to LAR Section 8.5). The system will also continue to be able to support its requirements for shared systems and components that are important to safety to perform safety related functions. The Main Steam System maintains its ability to transfer heat (residual and sensible) from the Reactor Coolant System. The safety related portions of the Main Steam System continue to be able to withstand the effects of external missiles and internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks (LAR Section 8.5).

The applicable General Design Criteria (2, 4, 5, and 34) continue to be met. (Refer to LAR Section 8.5 for General Design Criteria 4.)

8.4.2 EXTRACTION STEAM

8.4.2.1 DESCRIPTION

The Extraction Steam System is not specifically described in the Seabrook Station UFSAR. Seabrook Station UFSAR Section 10 evaluates the turbine water induction aspects of this system. The system is non-safety related. The evaluation of the system and its components demonstrates that the current design is acceptable to support operation for SPU. The original turbine supplier (General Electric Engineering Services) evaluated the Seabrook Station turbine. As part of the SPU, internal modifications to the high pressure turbine will be made to support the SPU steam conditions and will connect to existing portions of the Extraction Steam System. This turbine evaluation is contained in LAR Section 8.3.

The Extraction Steam System design functions are:

- To improve the design efficiency of the secondary plant
- Provide heating medium to the feedwater heaters
- To protect the steam turbine from overspeed and water induction.
- The Extraction Steam System provides steam from the turbine extraction points to the feedwater heaters.

The purpose of the evaluation of the Extraction Steam System is to demonstrate that the current design of the system is acceptable to support SPU operation.

8.4.2.2 EVALUATION

The Extraction Steam System was evaluated to ensure its ability to supply steam to the feedwater heaters at the SPU conditions. Existing design parameters were reviewed and compared against SPU conditions for system acceptability.

8.4.2.2.1 SYSTEM OPERATING CONDITIONS

Extraction Steam Pressure/Temperature

Extraction Steam System operating pressures and temperatures for SPU conditions are not significantly affected by the SPU and remain bounded by the original piping design specifications

Extraction Steam Velocities and Quality

The SPU flow velocity for the Extraction Steam piping remains within the acceptance criteria for steam velocities. Steam quality was evaluated and does not change significantly at the expected SPU conditions. The changes in steam flow velocity, as well as the minor changes in steam conditions will be incorporated into the Seabrook Station Flow Accelerated Corrosion Program.

Extraction Steam Flow and Pressure Drop

Extraction steam pressure drops increase for SPU due to the increased flow rates. The predicted pressure drops at SPU are acceptable and are included in the evaluations and thermal performance predictions.

8.4.2.2.2 COMPONENT DESIGN EVALUATION

The extraction steam non-return valves and isolation valves are acceptable at SPU conditions and will continue to function for turbine water induction prevention. The Extraction Steam expansion joints will be operating within design conditions at the SPU.

The SPU will not have a significant effect on the Extraction Steam piping drain capacity. The factors that affect drain flow will not be significantly affected by the SPU. Therefore, drain flow will not change significantly for SPU operation. The Extraction Steam drains are acceptable for SPU.

Existing Extraction Steam instrumentation is acceptable; refer to LAR Subsection 8.4.17.

8.4.2.3 CONCLUSION

The Extraction Steam System is acceptable for SPU operation without modification.

8.4.3 CONDENSATE AND FEEDWATER

8.4.3.1 DESCRIPTION

The Condensate and Feedwater Systems are discussed in Seabrook Station UFSAR Section 10.4.7. The evaluations of these systems and their components demonstrate that the current design is acceptable to support operation for an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The Condensate System was evaluated to assess capability in providing the following design functions after the implementation of the SPU:

- Satisfies steam generator feedwater pump suction flow requirements (along with the Heater Drains System),
- Maintains hotwell and condensate storage tank water storage capacity to support plant load changes,
- Improves plant cycle thermal efficiency,
- Provides continuous make-up flow to offset fluid losses during normal operation,
- Supplies make-up flow for Emergency Feedwater System operation,
- Supplies flow for various component uses (e.g., heater drain pump cold condensate injection, steam generator feedwater pump glands),
- Support off-normal operation (e.g., low pressure feedwater heaters or hotwell removed from service), and
- Support design transients and events.

The Feedwater System was evaluated to assess capability in providing the following design functions after the implementation of the SPU:

- Provide feedwater flow to the steam generators,
- Maintain the steam generator water level,
- Supply feedwater at the required temperature,
- Maintain containment isolation requirements,
- Support off-normal operation (e.g., high pressure feedwater heater or steam generator feedwater pump out of service)
- Support design accidents, transients, and events.

The evaluation of main condenser operation in support of the SPU is documented in LAR Subsection 8.4.7.

The dynamic effects associated with possible fluid flow instabilities (e.g., water hammers) during Condensate and/or Feedwater System operation were evaluated for SPU as documented in LAR Section 8.5.

8.4.3.2 EVALUATION

Condensate and Feedwater System components were evaluated to ensure required functions are performed after implementation of the SPU and, consequently, to ensure the functionality of the Condensate and Feedwater Systems. A hydraulic flow model of the systems was developed and used to evaluate system and component performance under normal and transient conditions.

Additionally, the ability of the Condensate and Feedwater Systems to support plant design basis load transients, and a step load change of 50% without a reactor trip, were also evaluated for the SPU.

8.4.3.2.1 SYSTEM OPERATING CONDITIONS

A hydraulic flow model of the Condensate and Feedwater Systems and SPU heat balances were used to predict SPU operating conditions. These conditions were compared to design specifications. Predicted SPU normal and transient conditions will remain below the Condensate and Feedwater System piping design values established by the applicable codes and existing analysis.

Slight increases in flow rate and velocities with SPU can affect the piping corrosion and erosion rates. As such, these increases will be incorporated into the Seabrook Station Flow Accelerated Corrosion program as part of the SPU implementation. Refer also to LAR Subsection 9.1.3.

8.4.3.2.2 COMPONENT DESIGN EVALUATION

Feedwater Regulating Valves

The pressure drop across the feedwater regulating valves yielded by the hydraulic flow model was used to determine the required valve flow coefficient for these valves. Using this flow coefficient and the characteristic curve for these valves, the resulting valve percent open was evaluated and compared to the normally accepted valve open position necessary to allow for flow instabilities and transients.

The feedwater regulating valves were determined to be acceptable for SPU operation based on the ability to control flow while maintaining adequate margin to full open.

Condensate and Steam Generator Feedwater Pumps

The hydraulic flow model was utilized to evaluate the capabilities of the condensate and the steam generator feedwater pumps, which included suction pressure, discharge pressure, and flow requirements.

The condensate pumps will be modified to provide additional flow and pressure margin at the new SPU operating point. The modifications to the condensate pump will provide additional pressure at the suction of the steam generator feedwater pumps to ensure additional net positive suction pressure under the current design scenarios, and ensure the turbine driven steam generator feedwater pump speed will remain approximately the same as for the current licensed power level

The condensate pump motors will remain within the current motor rating and are adequate for the SPU normal conditions.

The steam generator feedwater pumps have sufficient head and capacity margins to support SPU. The new steam generator feedwater pump operating point is within the design pump curve limits for flow, including consideration for not changing the current operating speed at SPU conditions.

The steam generator feedwater pump turbine capabilities were analyzed at SPU conditions and found to be acceptable for handling both normal and transient conditions.

Feedwater Heaters

The design of the feedwater heaters (shell and tube sides) were compared to predicted SPU flow conditions. The feedwater heater design specifications and current operating conditions were used to establish the design characteristics and to determine the impact of the SPU on these characteristics.

The feedwater heater tube side pressure and temperature design conditions at SPU are bounded by design. The tube side mass flow rates and the resulting flow velocities are bounded for the feedwater heaters, which includes a 10% tube plugging assumption.

The adequacy of feedwater heater shell side and tube side relief valves and vent lines, and the ability of the motor operated valves located in the extraction lines (and the bypass on the condenser neck feedwater heaters) to avoid water induction were also reviewed.

The feedwater heater tube side relief valves are designed to provide overpressure protection from thermal effects when the tube side is isolated. Therefore, these relief valves are not affected by the SPU.

The predicted SPU feedwater heater shell side operating temperatures and pressures are bound by design.

The feedwater heater shell side relief valves adequately support water relieving requirements at SPU. Additionally, the operating vents were analyzed and found to be capable of preventing non-condensable gas accumulation in the feedwater heaters.

The prevention of water induction into the turbine was also evaluated. The extraction and condensate line isolation valves actual closure times determined through periodic testing remain below the required closure times.

Instrumentation

Implementation of the SPU will necessitate re-banding the Main Control Room feedwater flow indicators, resetting the main steam/feed differential pressure input for the feedwater pump turbine speed control system, and modifying the setpoints for the condensate pump short term minimum flow recirculation pressure controllers. Refer to LAR Section 8.4.17 for detailed discussion.

8.4.3.2.3 GENERAL DESIGN CRITERIA

Evaluation of the Condensate and Feedwater Systems included consideration of General Design Criteria 4, Environmental and Missile Design Bases, in terms of possible fluid flow instabilities (e.g., water hammers) during normal and accident conditions. Refer to LAR Section 8.5.

General Design Criteria 5 (Sharing of Structures, Systems, and Components) does not apply as Seabrook Station is a single unit plant.

Consideration was also given to General Design Criteria 44, Cooling Water, in terms of satisfying feedwater flow requirements and system isolation. Implementation of the SPU will not impact the arrangement or isolation capability of the Condensate and Feedwater Systems nor, consequently, the ability of these systems to satisfy feedwater requirements.

8.4.3.3 CONCLUSION

In conclusion, the Condensate and Feedwater Systems will continue to meet their design functions following the implementation of the SPU, and meet the requirements of General Design Criteria 4 and 44.

8.4.4 EMERGENCY FEEDWATER

8.4.4.1 DESCRIPTION

The Emergency Feedwater System is discussed in Seabrook Station UFSAR Section 6.8. The evaluation of the Emergency Feedwater System and its components demonstrates that the current design is acceptable to support operation at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The Emergency Feedwater System was evaluated to assess capability in providing the following design functions after the implementation of the SPU:

- Supports core decay heat removal to achieve/maintain plant hot standby and, if necessary, achieve cold shutdown during those American Nuclear Society Condition II events (i.e., Faults of Moderate Frequency) when main feedwater is unavailable (e.g., reactor trip with or without a safety injection signal; loss of main feedwater with or without loss of offsite power),
- Supports core decay heat removal to accomplish plant cooldown following a main steam line break or main feedwater line break with or without a loss of offsite power,
- Isolates emergency feedwater flow to the faulted loop or steam generator following a main steam line break or main feedwater line break,
- Maintains steam generator water level following a small-break loss of coolant accident to augment depressurization of the Reactor Coolant System in support of achieving plant shutdown,
- Maintains water level in the intact steam generators following a steam generator tube rupture, and
- Maintains a static head above the steam generator tubes following a large-break loss of coolant accident to prevent primary-to-secondary leakage of fission products.

The Emergency Feedwater System is capable of limiting Reactor Coolant System peak pressure following a loss of load transient. Evaluation of this capability for SPU is documented in LAR Section 6.3.3.

Additionally, the Emergency Feedwater System discharge and branch headers are utilized by the Steam Generator Wet Lay-Up System for steam generator recirculation during Modes 4 through 6. This function is not impacted by SPU.

The evaluation of condensate storage tank inventory in support of SPU operation is documented in LAR Section 4.2. The current usable Condensate Storage Tank inventory based on Technical Specification minimum storage requirements (i.e., 196,000 gallons) remains acceptable for SPU.

The dynamic effects associated with possible fluid flow instabilities (e.g., water hammers) during Emergency Feedwater System operation were evaluated for SPU as documented in LAR Section 8.5. Evaluation of the impact of SPU on the potential for emergency feedwater pump binding due to backleakage of main feedwater past the emergency feedwater header stop check valves, however, is documented herein.

8.4.4.2 EVALUATION

Emergency Feedwater and Main Steam System components were evaluated to ensure required functions are performed after implementation of the SPU and, consequently, to ensure the functionality of the Emergency Feedwater System.

The licensing basis emergency feedwater flow requirements do not change for the SPU. Therefore, the existing hydraulic analyses are used to demonstrate the capability of the Emergency Feedwater System. The emergency feedwater flow requirements for plant cooldown and 10 CFR 50 Appendix R safe shutdown, which are bound by the engineering safeguards flow requirements, also do not change.

Similarly, existing evaluations are utilized to demonstrate the conservatism in the emergency feedwater flow rate assumed in the main steam line break analysis (i.e., 2295 gpm). The maximum calculated emergency feedwater flow rate to the intact steam generators following a main steam line break inside containment does not exceed the flow rate assumed in the main steam line break analysis to maximize Reactor Coolant System cooldown. This will not change for SPU.

8.4.4.2.1 SYSTEM OPERATING CONDITIONS

The design of Emergency Feedwater System and emergency feedwater turbine steam supply piping/components subjected to full-load main feedwater or main steam conditions are designed for the range of full-load to zero-load. As this range does not change for the SPU, the current design bounds predicted SPU operating conditions.

Initial inlet steam conditions for the emergency feedwater turbine, and those required at the end of the first phase of plant cooldown, will not change for SPU. Additionally, the current moisture separation design remains adequate.

The balance of the Emergency Feedwater System piping/components would not be impacted by the SPU as flow requirements, system operation, and system arrangement would not change for SPU.

8.4.4.2.2 COMPONENT DESIGN EVALUATIONS

Valves

The SPU will not impact the containment isolation function of the emergency feedwater header stop check valves and the emergency feedwater turbine steam supply admission valves as valve positions and/or predicted operating flow conditions are predicted to either not change or not increase.

Continuation of current surveillance and trending activities after implementation of the SPU were determined to be an acceptable means of identifying backleakage of main feedwater past the emergency feedwater header stop check valves. Consequently, SPU will not impact the potential for emergency feedwater pump steam binding.

The backup air supplies serving the Emergency Feedwater Turbine steam supply admission valves were determined to be adequate for SPU operation as required operating conditions do not change.

Pumps

The Emergency Feedwater Pumps and the Startup Feedwater Pump, which may be utilized as the backup for the Emergency Feedwater Pumps, would not be impacted by the SPU as flow requirements, system operation, system arrangement, and surveillance requirements would not change for SPU.

8.4.4.2.3 GENERAL DESIGN CRITERIA

Evaluation of the Emergency Feedwater System included consideration of General Design Criteria 4, Environmental and Missile Design Bases, in terms of the discussion provided in Seabrook UFSAR Section 3.1.1.4. This system will accommodate the effects of and be compatible with the environmental conditions after the implementation of the SPU (refer to LAR Section 9.2). Additionally, protections against dynamic events resulting from equipment failures or external events (i.e., missiles, pipe whip, etc.) would not be impacted by the SPU (refer to LAR Section 10.0).

Consideration was also given to General Design Criteria 19 (Control Room), 34 (Residual Heat Removal) and 44 (Cooling Water) in terms of system and equipment redundancy and transferring heat from the reactor core. Implementation of the SPU will not impact the arrangement or control of the Emergency Feedwater System nor, consequently, the ability of this system to satisfy feedwater requirements.

8.4.4.3 CONCLUSION

The Emergency Feedwater System design requirements do not change for SPU and, hence, the system and components will continue to provide core decay heat removal

following the implementation of the SPU. The Emergency Feedwater System will continue to support meeting the requirements of General Design Criteria 4, 19, 34, and 44.

8.4.5 STEAM GENERATOR BLOWDOWN

8.4.5.1 DESCRIPTION

The Steam Generator Blowdown System is discussed in Seabrook Station UFSAR Section 10.4.8. The evaluation of the Steam Generator Blowdown System demonstrated that the current design of the system is acceptable to support SPU operation. The Steam Generator Blowdown System is designed to process blowdown water from the secondary side of the steam generator by removing particulates and dissolved solids, thereby maintaining optimum secondary side water chemistry in the steam generators. By maintaining the proper water chemistry on the secondary side of the steam generators during normal and anticipated abnormal operating conditions, corrosion of steam generator tubes is reduced, thereby minimizing the likelihood and magnitude of tube leaks.

8.4.5.2 EVALUATION

The Steam Generator Blowdown System and components were evaluated to ensure they are capable of performing their intended functions at SPU conditions. The blowdown flowrates required during plant operation are based on steam generator chemistry control and tube-sheet sweep requirements to control the buildup of solids. The blowdown flowrate required to control chemistry and the buildup of solids in the steam generators is tied to allowable condenser in-leakage, total dissolved solids in the Feedwater System, and the allowable primary to secondary leakage. Since these variables are not impacted by the SPU, the blowdown required to control secondary chemistry and steam generator solids will not be impacted by SPU.

The no-load conditions (0 % power) do not change and the nominal 100% power operating conditions do not change significantly with SPU. Minor increases in feedwater temperatures will not negatively impact the function of the blowdown heat exchangers to cool blowdown flash tank drains below demineralizer resin temperature limits. General Design Criteria -14 (Reactor Coolant Pressure Boundary) is not impacted as the bounding conditions do not change. Therefore, the Steam Generator Blowdown System is acceptable for SPU.

8.4.5.3 CONCLUSION

As the required blowdown flow does not change, and the steam pressure and temperatures associated with the SPU are bounded by the design of the Steam Generator Blowdown System and its components with margin, the Steam Generator Blowdown System is acceptable for SPU. The Steam Generator Blowdown System will continue to meet the requirements of General Design Criteria 14.

8.4.6 MAIN CONDENSER EVACUATION SYSTEM

8.4.6.1 DESCRIPTION

The evaluation of the Main Condenser Evacuation System demonstrated that the current design of the system is acceptable for SPU operation. The Main Condenser Evacuation System is discussed in the Seabrook Station UFSAR Section 10.4.2. The evaluation of the Main Condenser Evacuation System is acceptable to support operations at SPU conditions.

The Main Condenser Evacuation System consists of two independent subsystems: the shell side evacuation subsystem and the water box priming subsystem. The system has no safety design basis; however, the following design criteria are applicable:

- The shell side evacuation subsystem removes non-condensable gases and air in-leakage from the steam space of the main condenser shells. This system is sized to achieve and maintain shell side vacuum in the condenser to permit plant startup and operation.
- The waterbox priming subsystem removes the non-condensable gases from the condenser waterboxes (tube side) during startup and normal operation.

8.4.6.2 EVALUATION

The capacity of the shell side evacuation system was evaluated at SPU operating conditions and it was shown to meet the requirements of the Heat Exchange Institute. As the system design does not change and required system capability at SPU conditions is bounded by the current design, the current radiation monitoring equipment for the Main Condenser Evacuation System continues to meet the requirements for General Design Criteria 64.

Rad Waste effluents are evaluated in LAR Subsection 8.4.15.2.1 and demonstrate that plant releases meet regulatory limits. Therefore, the Main Condenser Evacuation System will continue to meet the requirements of General Design Criteria 60 at SPU.

The water box priming system was evaluated and determined to have sufficient capacity for SPU operating conditions.

8.4.6.3 CONCLUSION

Both the existing shell side evacuation system and the water box priming system are adequate for SPU conditions. There should be no measurable increase in dissolved oxygen concentrations in condensate with SPU. The Main Condenser Evacuation System will continue to meet the requirements of General Design Criteria 60 and 64. Therefore, the Main Condenser Evacuation System is acceptable for SPU operation without modification.

8.4.7 MAIN CONDENSER AND CIRCULATING WATER

8.4.7.1 DESCRIPTION

The Main Condenser and Circulating Water Systems is discussed in the Seabrook Station UFSAR Sections 10.4.1 and 10.4.5. The evaluation of the Main Condenser and Circulating Water Systems demonstrates that the current design is acceptable to support operations at SPU conditions.

The main condenser is designed to function as a steam cycle heat sink receiving and condensing exhaust steam from the main turbine and steam generator feedwater pump turbines. In addition it provides the following additional functions:

- Receives and condenses turbine bypass steam flow
- Provides a collection point for vents and drains from various components and systems of the heat cycle
- De-aerates the condensate

The Circulating Water System delivers cooling water from the Atlantic Ocean to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems and conveys the heated discharge water back to the Atlantic Ocean. The principal structures of the Circulating Water System are tunnels, offshore structures, transition structures, circulating water pumps, circulating water pumphouse, traveling screens, the screenwash system and the chlorination system. During normal operation, the Circulating Water System provides a flow of approximately 470,000 gpm to the main condenser.

8.4.7.2 EVALUATION

Circulating Water System operating pressures do not change for SPU. Circulating Water temperatures are not significantly affected by the SPU and remain bounded by the original design. Also, the SPU flow velocity for the Circulating Water piping is unchanged with SPU as the Circulating Water flowrate is unchanged. At SPU conditions, with normal Circulating Water flow, the circulating water outlet temperature will increase approximately 2.2°F from the current power level. The maximum SPU Circulating Water outlet temperature is within current system design parameters. Circulating Water System thermal performance remains acceptable at the SPU conditions.

Current main turbine bypass steam flow rate and total energy to the condenser bounds SPU operation, and is therefore acceptable. Also see LAR Subsection 8.4.1 (Turbine Bypass).

Condenser tube vibration has been analyzed for conditions more severe than those predicted for SPU (full load operation with one of the three condenser sections out of service) and found to be acceptable in its current configuration. The condenser is therefore acceptable for SPU operating conditions relative to tube vibration.

The relatively small (7%) increase to low pressure turbine exhaust and main feed pump turbine exhaust flow rates at SPU operating conditions will not significantly increase the potential for damage to condenser internals. In addition, the condenser is inspected during each refueling outage for internal damage.

As the Circulating Water Systems flow conditions (pressure, temperature, flow) do not change significantly with SPU, flooding conditions are unaffected by SPU. Therefore, General Design Criteria 4 is satisfied at SPU

Rad Waste effluents are evaluated in LAR Subsection 8.4.15.2.1 and demonstrate that plant releases meet regulatory limits. Therefore, the Main Condenser and Circulating Water Systems will continue to meet the requirements of General Design Criteria 60 at SPU.

8.4.7.3 CONCLUSION

The Main Condenser System and Circulating Water System will continue to maintain its ability to withstand the blowdown effects of the steam from the turbine bypass system and thereby continue to meet the requirements of General Design Criteria 4 and 60 for prevention of the consequences of failures in the system. Circulating Water System flows and pressures do not significantly change with SPU operating conditions. Therefore, calculated volumes of fluid leakage from failed components will not change at SPU operating conditions. Current flooding analyses of the Main Condenser and Circulating Water Systems remain valid for SPU, which demonstrate that flooding will not result in the failure of safety-related systems, structures and components.

8.4.8 HEATER DRAINS

8.4.8.1 DESCRIPTION

The Heater Drains and Moisture Separator / Reheater Drains Systems are not specifically described in the Seabrook Station UFSAR. These systems are non-safety related. The evaluation of these systems and their components demonstrates that the current design is acceptable to support operation at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The Feedwater Heaters and Moisture Separator / Reheater Drain Systems collect the condensed steam in the feedwater heaters and moisture separator / reheaters and returns the condensate to the Condensate System. The heater drains cascade to the lower pressure feedwater heaters and then to the main condenser or heater drain tank. The moisture separator drains flow to the heater drain tank while the reheater drains are directed to the high pressure feedwater heaters.

The Heater Drains and Moisture Separator / Reheater Drains System were evaluated for:

- The capacity of the normal and emergency drain lines,
- The adequacy of the control valves for SPU conditions,

- Heater drain pump flow, head and net positive suction head,
- Effects of heater drain loss during load transients,
- Impact of SPU on heater drain tank instability,
- Stability and flow regimes of two phase flow in drain lines.

8.4.8.2 EVALUATION

The Heater Drains and Moisture Separator / Reheater Drains Systems were evaluated to ensure their ability to collect and redistribute condensation at the SPU conditions. Existing operating and design parameters were reviewed and compared against SPU conditions for system acceptability.

8.4.8.2.1 SYSTEM OPERATING CONDITIONS

Feedwater Heater and Moisture Separator Drain Pressure / Temperature

The expected SPU operating pressures and temperatures for the feedwater heater drains and moisture separator drain lines were compared to the pipe and valve design ratings as listed on the system flow diagram or valve data sheets.

Although the SPU conditions in most cases exceed the current operating conditions, the system pipe and component design pressure and temperature ratings exceed the drain line SPU operating pressures and temperatures conditions. Therefore, SPU conditions are bounded by the present design.

Heater Drain and Moisture Separator / Reheater Velocities

The velocity in these drain lines was evaluated based on the flow of sub-cooled water with the exception of feedwater heaters E-25 and the moisture separator/reheater drain lines, which are not sub-cooled. The SPU flow velocities in the drain lines are within industry design guidelines.

Changes in drain velocities, as well as minor changes in temperature and pressure will be incorporated into the Seabrook Station Flow Accelerated Corrosion Program (Refer to LAR Subsection 9.1.3).

8.4.8.2.2 COMPONENT DESIGN EVALUATIONS

Heater Drain and Reheater Drain Tanks

The heater drain tank and reheater drain tanks were evaluated for SPU pressure and temperature conditions. Both are shown to be bound by the existing tank design parameters and are acceptable for operation at SPU.

SPU flows to the reheater drain tanks will be less than current operating flows due to modifications to the moisture separators reheaters. The modifications will improve the moisture removal capability of the separators and thus reduce the overall reheat steam required. The existing reheater drain tanks and associated controls are adequate for SPU.

The heater drain tank met the required sizing criteria to provide stable level control. Tuning of the level control system software will be required to support the SPU operating conditions.

Heater Drain Pumps

Slight increases in temperature, pressure and flow requirements will have little significance and are within the pump original specified values. The heater drain pumps will operate at slightly lower brake horsepower than at the current power levels as a result of the characteristics of the pump curve at the higher flow and lower head requirements.

Feedwater Heaters

SPU will result in an increase in the mass flow rates for the feedwater heater drain lines and an increase in flow velocity. The heater drain inlet mass velocities and energy parameters were calculated for feedwater heaters that receive cascading drains to check conformance with Heat Exchange Institute guidelines.

The mass velocity and energy criteria was evaluated at the current and SPU conditions and found acceptable for the nozzles with the exception of two nozzles, which marginally exceeded energy acceptance criteria. These nozzles will be identified to the Seabrook Station Flow Accelerated Corrosion Program Coordinator for future trending.

Level Control Valve Capabilities

The normal and emergency drain level control valves were evaluated and compared for percent of Cv change and the percent of open position. The valves evaluated were found to be acceptable for operation at SPU without change. The level control valve open positions that range from 38% to 80% at current conditions will range from 38% to 84% after SPU. Tuning of selected level control system loops will be performed as needed for SPU operating conditions

Drain Lines

The drain lines were found to be acceptable for operation at SPU with the exception of the normal self venting drains from the number 5 feedwater heaters (E-25A and B) and the gravity drain lines from the shell sides of the moisture separators. The drain lines from E-25A and B did not meet the acceptance criteria established for "self venting drain lines". Modification of these drain lines, such as providing an appropriate slope, increasing the line size and/or providing additional venting capability will be implemented for operation at SPU.

The gravity drain portion of each moisture separator shell drain line has a loop seal between the moisture separator and the heater drain tank. At SPU conditions the differential pressure between the moisture separators and the heater drain tank will increase to a point that the loop seals may not be maintained. In order to provide additional margin to ensure the loop seal is maintained modification, such as adding

a valve or orifice to each moisture separator drain line to provide additional system resistance, will be provided.

Instrumentation

Instrumentation and / or controls associated with Feedwater Heater Drains and Moisture Separator / Reheater drains are not expected to change as a result of SPU. Some tuning may be necessary at the time of startup, however no hardware changes are anticipated. Refer to LAR Subsection 8.4.17.

8.4.8.3 CONCLUSION

The heater drain and moisture separator / reheater drain piping and component pressures and temperatures at SPU are bound by existing conditions. The level control valve openings were calculated at SPU conditions and determined to be within an acceptable operating range with margin. Drain line velocities and heater nozzle velocities were checked at SPU conditions and were within either Heat Exchange Institute or other industry standard established industry practices. Minor increase in drain velocities, pressures and temperatures are expected to have little influence on the Seabrook Station Flow Accelerated Corrosion Program. With appropriate modification to the E-25A and B and moisture separator drain lines, the Heater Drain System will operate satisfactorily at SPU conditions.

8.4.9 SPENT FUEL POOL COOLING

8.4.9.1 DESCRIPTION

The Spent Fuel Pool Cooling System is described in Seabrook Station UFSAR Section 9.1.3. The Spent Fuel Pool Cooling System is designed to remove decay heat from the spent fuel to maintain the spent fuel pool below a maximum temperature of 140°F during normal operation and ensure that no boiling occurs during abnormal operation. Recently the Nuclear Regulatory Commission approved an LAR that changed the minimum time to initiate fuel movement to 80 hours after reactor shutdown [Reference 8.4-3]. In addition the Spent Fuel Pool Cooling System:

- Continuously maintains a minimum of 13 feet of water over the spent fuel elements to shield personnel, and
- Maintains the chemical parameters and optical clarity of the spent fuel pool water, and the water in the reactor cavity and refueling canal during refueling operations.

The spent fuel cooling pumps take suction from the pool and circulate water through the heat exchangers, which are cooled by the Primary Component Cooling Water System. Pool water enters the suction line through a strainer near one wall of the pool thirteen feet higher than the return line terminations.

The system connections to the fuel pool penetrate at elevations sufficiently above the top of the fuel to maintain adequate shielding in the event water level drains to the penetration level.

Spent fuel pool water quality is maintained by a pool skimmer loop which filters and demineralizes the circulated water.

The spent fuel pool cooling and cleanup system design temperature is 200°F, with a design pressure of 150 psig.

Refueling Outages at Seabrook Station are scheduled during the Spring and Fall time periods. During these time frames the maximum ocean temperature is routinely less than 65°F. The Spent Fuel Pool Cooling System is capable of cooling a full spent fuel pool including the heat load for a full reactor core offload using a design basis ocean temperature of 65°F. The current offload procedure, which contains a figure plotted against time after shutdown and service water temperature will be revised to control the time that the core offload can be completed at the SPU conditions.

The Spent Fuel Pool Cooling System design basis capability uses the ocean Service Water System as the ultimate heat sink. During the offload time frame the cooling tower may be in service functioning as the ultimate heat sink.

8.4.9.2 EVALUATION

The analyzed SPU core power level for this evaluation is 3659 MWt as compared to the current licensed core power of 3411 MWt. Since the decay heat rate of the spent fuel is a function of the power level, the spent fuel pool cooling heat load will increase. This increase will result in higher heat loads being transferred to the Primary Component Cooling Water System and Service Water System.

Normal Operation with Ocean Service Water Evaluation:

At the design heat load of 46.44×10^6 Btu/hr under normal operation with 65°F service water, the Spent Fuel Pool Cooling System (assuming a single failure) is capable of maintaining the spent fuel pool less than or equal to 140°F. This heat load corresponds to completion of a full core offload plus residual heat from all previously discharged assemblies at approximately 134 hours (versus 118.5 hours at current power level) after shutdown.

By reducing the service water temperature from 65°F to approximately 59.3°F (versus 62.9°F at current power level), with two spent fuel pool cooling trains operable (two pumps and two heat exchangers), one primary component cooling water loop supplying both heat exchangers (i.e., single failure of one primary component cooling water pump), and the Atlantic Ocean as the ultimate heat sink, a full core offload beginning at 80 hours after shutdown, proceeding at a rate of 6 assemblies per hour, can be completed at 110 hours after shutdown without exceeding the 140°F acceptance limit on the spent fuel pool water temperature. Therefore, for the offload rates that result in the full core being offloaded in less than 134 hours, credit for service water temperatures less than the 65°F design limit is

required. The current operating procedures, which address similar restrictions, will be revised to provide guidance for offload completion in less than 134 hours to ensure that the spent fuel pool temperature will remain less than or equal to 140°F. The design basis capability of the Spent Fuel Pool Cooling System along with these revised procedural controls will provide assurance that the spent fuel pool will operate within design limits.

Normal Operation with Cooling Tower Evaluation:

As discussed above, the design basis condition assumes the Atlantic Ocean as the ultimate heat sink. Administrative controls will be established to include guidance on the acceptable conditions for maintaining spent fuel temperatures less than or equal to 140°F when the cooling tower is the ultimate heat sink. Procedures will be in place and the work planned, so that the protected train of ocean service water can be rapidly returned to service in the event that the cooling tower Service Water System becomes unavailable.

Abnormal Operation Evaluation:

Under abnormal refueling operation, the Atlantic Ocean is assumed unavailable and cooling is provided by the Ultimate Heat Sink (cooling tower). One train of service water based upon design wet bulb temperature of 75°F supplies one primary component cooling water loop with two spent fuel pool cooling trains operable. This abnormal case was evaluated assuming a full spent fuel pool and a full core off-load beginning 80 hours after reactor shutdown [Reference 8.4-3]. The maximum spent fuel pool temperature was determined to be 159°F (versus 155.7°F at current power level), and no boiling would occur anywhere in the pool as long as offload was completed a minimum of 108 hours after reactor shutdown.

Bulk Boiling Evaluation:

In the unlikely event of a total loss of spent fuel pool cooling, sufficient time is available for operators to take action before the pool reaches bulk boiling to provide makeup and maintain water level. The time for the spent fuel pool to heat up from 140°F to 212°F has been calculated assuming an adiabatic heatup.

Assuming the core offload begins 80 hours [Reference 8.4-3] after shutdown and proceeds at a rate of 6 assemblies per hour, with the full core offload achieved at 110 hours after shutdown, the total decay heat load in the spent fuel pool including uncertainty is calculated to be approximately 50.1×10^6 Btu/hr at SPU conditions (versus 47.79×10^6 Btu/hr at current power level). With a minimum spent fuel pool water level at an elevation of 23 feet 6 inches (greater than 25 feet of water over the spent fuel), the time to heat up the spent fuel pool from 140°F to 212°F is calculated as 3.13 hours (versus 3.28 hours at current power level). At this heat load a boil-off rate of approximately 104 gpm (versus approximately 100 gpm at current power level) would exist which is within the makeup capacity of the pool. Makeup sources include the refueling water storage tank, demineralized water, and the Chemical and Volume Control System. All of these sources are capable of providing makeup flows

in excess of 104 gpm and are readily available and accessible. For current and SPU operation, more than 25 feet of water is maintained over the spent fuel .

Structural Evaluation:

In addition to the maximum spent fuel pool water temperature, the spent fuel pool concrete wall temperature at SPU conditions was evaluated and determined to remain within the current design values.

Miscellaneous Evaluations:

The SPU is not expected to affect the impurity levels in the spent fuel pool and the design of the cleanup system will not be impacted.

Since the analysis has determined that the pool will remain within current limits and there are no physical or operational changes to the Spent Fuel Pool Cooling System required for the power uprate, the Spent Fuel Pool Cooling System instruments and controls are not affected.

8.4.9.3 CONCLUSION

The effects of SPU on the spent fuel pool cooling and cleanup system have been evaluated and it has been determined that the temperature of the spent fuel pool water temperature will remain less than 140°F for normal refueling and spent fuel pool boiling will not occur for abnormal refueling. The Spent Fuel Pool Cooling System will continue to adequately cool the spent fuel pool following SPU and is considered acceptable.

8.4.10 CONTAINMENT BUILDING SPRAY

8.4.10.1 DESCRIPTION

The Containment Building Spray System is described in Seabrook Station UFSAR Section 6.5.2. The evaluation of the Containment Building Spray System demonstrated the current design is acceptable to support SPU. The Containment Building Spray System limits offsite fission product release and dose consequences by removing iodine concentrations in the containment atmosphere during a design basis loss of coolant accident. The Containment Building Spray System also limits containment atmosphere pressure and temperature rise post design basis accident.

8.4.10.2 EVALUATION

The evaluation of the Containment Building Spray System at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) demonstrated the current design remains bounded at SPU conditions. Using mass and energy releases for a Loss of Coolant Accident (LOCA) (refer to LAR Subsection 6.4.1.1) and Main Steam Line Break (refer to LAR Subsection 6.4.4.1), an analysis has shown the peak containment pressure and temperature post design basis accident at SPU is bounded by the current peak containment pressure and temperature such that General Design Criteria 38 requirements for rapidly reducing the containment

pressure and temperature following a loss of coolant accident and maintaining them at acceptably low levels is still met. Containment Building Spray system pumps, heat exchangers, spray rings and nozzles, and associated valves and piping design temperatures and pressures are acceptable for SPU. Containment building spray system pumps net positive suction head and heat exchangers heat removal capability are acceptable for the SPU.

The off-site dose aspect related to the Containment Building Spray System is not part of this evaluation. Refer to Licensing Amendment Request Number 03-02 [Reference 8.4-1] which addresses the implementation of Alternative Source Term at the SPU core power level and the radiological aspects of the Containment Building Spray System.

8.4.10.3 CONCLUSION

The Containment Building Spray System will continue to meet the requirements of General Design Criteria 38 for rapidly reducing the containment pressure and temperature following a loss of coolant accident and maintain them at acceptably low levels. It is therefore concluded that following SPU, the Containment Building Spray System will continue to meet its design functions.

8.4.11 ULTIMATE HEAT SINK

8.4.11.1 DESCRIPTION

The Ultimate Heat Sink is discussed in Seabrook Station UFSAR Section 9.2. The evaluation of the Ultimate Heat Sink and its components demonstrates that the current design is acceptable to support operation at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The Atlantic Ocean serves as the normal supply for the Service Water System. In the unlikely event that the normal supply of cooling water from the Atlantic Ocean is unavailable, the atmosphere serves as the Ultimate Heat Sink through the use of a mechanical draft evaporative cooling tower.

8.4.11.2 EVALUATION

The Service Water System was evaluated at SPU conditions for normal operation with the Atlantic Ocean as the source and during a LOCA with the cooling tower as the Ultimate Heat Sink.

The results of the evaluation demonstrate that the total heat loads during normal operation are bounded by the design values, and the SPU heat loads for LOCA are bounded by the cooling tower design. Refer to LAR Subsection 8.4.12 for a comparison of heat loads.

In addition, the evaluation demonstrated that the system flows are unchanged at SPU conditions.

The Service Water System at Seabrook Station is a single unit, therefore General Design Criteria 5 regarding shared systems does not apply.

The SPU heat loads to the Ultimate Heat Sink are bounded by design, therefore the requirements of General Design Criteria 44 will continue to be met.

8.4.11.3 CONCLUSION

The effects of the SPU on the Atlantic Ocean and the cooling tower as the Ultimate Heat Sink have been evaluated and it has been determined that no equipment or operational changes are required for the SPU. The SPU will not compromise the design-basis safety function of the Ultimate Heat Sink. The Ultimate Heat Sink will continue to meet its licensing basis and satisfy the requirements of General Design Criteria 44 following implementation of the SPU.

8.4.12 SERVICE WATER

8.4.12.1 DESCRIPTION

The Service Water System is described in the Seabrook Station UFSAR Section 9.2.1. The evaluation of the Service Water System and its components demonstrates that the current design is acceptable to support operation at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The Service Water System consists of two completely independent and redundant flow trains, each of which supplies cooling water to a primary component cooling water heat exchanger, a diesel generator jacket water cooler, the secondary component cooling water heat exchangers, the auxiliary secondary component cooling water heat exchangers, the condenser water box priming pump seal water heat exchangers, and, except during a LOCA, to the Fire Protection System during a fire.

8.4.12.2 EVALUATION

The Service Water System was evaluated at SPU conditions for normal operation with the Atlantic Ocean as the source and during a LOCA with the cooling tower as the Ultimate Heat Sink.

The results of the evaluation demonstrate that the total SPU heat loads during normal operation are bounded by the design values, and the SPU heat loads for LOCA are bounded by the cooling tower design.

The heat loads are listed in LAR Tables 8.4.12-1 and 8.4.12-2.

The evaluation of the Service Water system demonstrated that the flows are unchanged at SPU conditions, and that the current design remains bounded for operation at the SPU conditions. With no change in flow rates the Service Water System will continue to meet the requirements of General Design Criteria 4 regarding protection from the dynamic effects associated with flow instabilities (e.g., water hammer).

The Service Water System at Seabrook Station is a single unit, therefore General Design Criteria 5 regarding shared systems does not apply.

The SPU heat loads for the Service Water System are bounded by design, therefore the system will continue to meet the requirements of General Design Criteria 44.

The Service Water System does not penetrate the containment, therefore GL 96-06 does not apply.

For Nuclear Regulatory Commission Generic Letter 89-13, the impact of the SPU heat removal capability of safety related heat exchangers cooled by the Service Water System is addressed in LAR Subsection 8.4.13.1.

8.4.12.3 CONCLUSION

The effects of SPU on the Service Water System have been evaluated and it has been determined that the system is capable of handling the additional heat loads that occur as a result of SPU without a change in flow rates. With no change in flow rates, the Service Water System will continue to be protected from the dynamic effects associated with flow instabilities. The system will also continue to provide sufficient cooling for equipment important to safety following implementation of the SPU. No equipment or operational changes are required for the SPU. The Service Water System will continue to meet its licensing basis and satisfy the requirements of General Design Criteria 4 and 44 following implementation of the SPU.

8.4.13 COMPONENT COOLING WATER

8.4.13.1 PRIMARY COMPONENT COOLING WATER

8.4.13.1.1 DESCRIPTION

The Primary Component Cooling Water System is described in Seabrook Station UFSAR Section 9.2.2. The evaluation of the Primary Component Cooling Water System and its components demonstrates that the current design is acceptable to support operation at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The Primary Component Cooling Water System provides cooling to reactor auxiliaries and other heat exchangers in the reactor building. The system consists of loops A and B, which are two independent and redundant flow loops and a reactor coolant pump thermal barrier loop. Loops A and B each supply component cooling water to one of the redundant components performing engineered safeguard functions, to the reactor coolant pump thermal barrier loop and to other non-safeguard loads. The Primary Component Cooling Water System is cooled by service water (refer to LAR Subsection 8.4.12).

The Primary Component Cooling Water System design temperature is 200°F, with a design pressure of 150 psig.

8.4.13.1.2 EVALUATION

The Primary Component Cooling Water System was evaluated at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) for normal operation, normal cooldown, extended cooldown and LOCA conditions. During normal operation and normal cooldown both cooling water loops are in operation. Extended

cooldown and LOCA cases are analyzed based on single loop operation. Heat loads for Primary Component Cooling Water System loops A and B are shown in LAR Tables 8.4.13.1-1 and 8.4.13.1-2.

The total heat loads for the Primary Component Cooling Water system for normal operation and normal cooldown at SPU conditions are bounded by the design values.

Although the SPU heat loads for extended cooldown and LOCA are greater than the original values, they are bounded by the primary component cooling water heat exchanger design rating, resulting in the heat exchanger outlet temperatures remaining bounded by the design values of 102°F for extended cooldown and 126°F for LOCA.

The evaluation demonstrated that the system flow requirements are unchanged at SPU conditions.

The requirements of General Design Criteria 4 are met at SPU since the system flows are unchanged. The heat exchanger performance at SPU is bounded by design, therefore the system will continue to meet the requirements of General Design Criteria 44 related to heat removal. The containment temperature after SPU is bounded by design, therefore the system will continue to meet the requirements of Nuclear Regulatory Commission Generic Letter 96-06.

8.4.13.1.3 CONCLUSION

The effects of SPU on the Primary Component Cooling Water System have been evaluated and it has been determined that the system is capable of handling the additional heat loads that occur as a result of the SPU without a change in flow rates. No equipment or operational changes are required for the SPU.

The Primary Component Cooling Water system will continue to meet its licensing basis and satisfy the requirements of General Design Criteria 4 and 44, and Generic Letter 96-06.

8.4.13.2 SECONDARY COMPONENT COOLING WATER

The Secondary Component Cooling Water system is described in the Seabrook Station UFSAR Section 10.4.10. The individual Secondary Component Cooling Water component heat loads considered in the original design remain bounding under the SPU.

The Secondary Component Cooling Water system is a non-safety related system and has no safety design basis. The Secondary Component Cooling Water system is a closed loop system cooled by the service water system (Refer to LAR Subsection 8.4.12). The system provides cooling to the turbine-generator auxiliary systems (e.g., main generator hydrogen coolers, stator coolers, turbine lube oil coolers, iso-phase bus duct cooling) as well as other heat loads in and adjacent to the turbine building (pump bearing and seal water, motor cooling).

The Secondary Component Cooling Water system is conservatively designed and the operating system flows and heat loads do not increase as a result of the SPU. SPU conditions are thus bounded by the original design. No modification of the system or components is required and the system will continue to meet its design requirements under SPU conditions.

8.4.14 HEATING, VENTILATION AND AIR CONDITIONING

8.4.14.1 DESCRIPTION

The Heating, Ventilation, and Air Conditioning Systems are described in Seabrook Station UFSAR Section 9.4. The evaluation of the Heating, Ventilation, and Air Conditioning Systems demonstrated that the current design is acceptable to support SPU conditions. The Heating, Ventilation, and Air Conditioning systems provide cooling, heating, ventilation, and/or filtration of plant areas to maintain a suitable environment for plant personnel and equipment.

8.4.14.2 EVALUATION

The evaluation included the following Heating, Ventilation, and Air Conditioning Systems to ensure that sufficient margin and capability exist to operate satisfactorily following implementation of the SPU. The evaluation was performed at an analyzed core power level of 3659 MWt (3678 MWt NSSS power level). The following systems were evaluated to determine the impact due to implementation of SPU.

- Control Room Complex Heating, Ventilation, and Air Conditioning System
- Fuel Storage Building Heating and Ventilation System
- Primary Auxiliary Building Heating and Ventilation System
- Waste Processing Building Heating, Ventilation and Air Conditioning System
- Containment Structure Heating, Cooling and Purge System
- Containment Enclosure and Adjoining Areas Cooling and Ventilation System
- Electrical Penetration Area Air Conditioning System
- Diesel Generator Building Heating and Ventilation System
- Cable Spreading Room Ventilation System
- 4-KV Switchgear Area, Battery Rooms and Electrical Tunnels Heating and Ventilation System
- Emergency Feedwater Pumphouse Heating and Ventilation System
- Administration and Service Building Heating, Ventilation and Air Conditioning System
- Service Water Pumphouse Heating and Ventilation System
- Service Water Cooling Tower Heating and Ventilation System
- Turbine Building Heating, Ventilation and Air Conditioning System

8.4.14.2.1 CONTROL ROOM COMPLEX HEATING, VENTILATION, AND AIR CONDITIONING SYSTEM

Control Room Complex Heating, Ventilation, and Air Conditioning System is safety related and provides a controlled environment for personnel and equipment, including maintaining temperature and humidity control. The Control Room Complex Heating, Ventilation, and Air Conditioning System includes a filter subsystem that provides emergency makeup air to the Control Room to maintain it at a positive pressure and filters makeup/ recirculation air for retaining airborne particulates and to absorb radioactive iodine which may penetrate the Control Room during accident conditions.

The heat loads to the Control Room Complex Heating, Ventilation, and Air Conditioning System were evaluated and are not expected to increase following implementation of the SPU.

The effect of the SPU on offsite and Control Room doses is addressed in License Amendment Request 03-02 submitted to the NRC by FPLE letter NYN-03061, dated October 6, 2003 [Reference 1.1-1] for implementation of Alternative Source Terms methodology for Seabrook Station.

8.4.14.2.2 FUEL STORAGE BUILDING HEATING AND VENTILATION SYSTEM

The Fuel Storage Building Heating and Ventilation system is designed to distribute filtered outside air throughout the Fuel Storage Building to offset heat loads during the summer and heat loss during the winter.

The safety related portion of the Fuel Storage Building Air Handling System includes an Emergency Air Cleanup Subsystem that is designed to limit tritium concentrations in the Fuel Storage Building below the maximum permissible concentration during fuel handling operations. The design air temperature in the Fuel Storage Building is 104°F.

The decay heat loads in the spent fuel pool in the Fuel Storage Building are proportional to the power level. Under normal SPU refueling mode, the spent fuel pool water temperature does not exceed the current design basis temperature limit of 140°F (Refer to LAR Subsection 8.4.9). Therefore, no additional heat load on the ventilation system at SPU is expected. Other heat sources in the Fuel Storage Building are from electrical equipment and ambient outside air temperature. None of these sources will increase at SPU. Therefore, the Fuel Storage Building Heating and Ventilation system's ability to provide required temperature conditions for personnel and equipment during all modes of operation are bounded by pre-SPU design.

During fuel handling operations with irradiated fuel not sealed in a shipping cask, the Fuel Storage Building is maintained at a negative pressure by the safety related exhaust filter units. The effect on the Fuel Storage Building Emergency Air Cleaning Subsystem maintaining offsite and Control Room doses are addressed in FPLE letter NYN-03061, dated October 6, 2003 that included a licensing amendment request to

the NRC (LAR 03-02) for implementation of Alternative Source Terms [Reference 1.1-1].

8.4.14.2.3 PRIMARY AUXILIARY BUILDING HEATING AND VENTILATION SYSTEM

The Primary Auxiliary Building Heating and Ventilating System is designed to provide circulation of outside air for removal of Primary Auxiliary Building heat generated by lighting and equipment in the summer, and to offset Primary Auxiliary Building heat losses in the winter. The Primary Auxiliary Building Heating and Ventilation System includes a once-through supply & exhaust subsystem for ventilation of normally clean areas; and a filtered exhaust subsystem used to collect air from potentially contaminated areas in the Primary Auxiliary Building and the Containment Enclosure Area.

The safety related portions of the system are the supply subsystem serving the Fuel Storage Building, exhaust ductwork for the Charging Pump Rooms, and the Primary Component Cooling Water Pumps and Boron Injection Pumps area emergency ventilation subsystem.

The heat loads to the Primary Auxiliary Building Heating and Ventilating System were evaluated and are not expected to increase following implementation of the SPU.

The effect on the Primary Auxiliary Building filtered exhaust subsystem maintaining offsite and Control Room doses is addressed in FPLE letter NYN-03061, dated October 6, 2003 [Reference 1.1-1] that included a licensing amendment request to the NRC (LAR 03-02) for implementation of Alternative Source Terms.

8.4.14.2.4 CONTAINMENT STRUCTURE HEATING, COOLING, AND PURGE SYSTEM

The Containment Structure Heating, Cooling, and Purge System includes the following subsystems:

The Containment structure cooling subsystem is designed to ensure that the Containment Structure is maintained at or below 120°F bulk air temperature.

The Containment structure recirculation filter subsystem, online purge subsystem, and air purge & heating subsystems are able to reduce airborne contamination to acceptable level prior to personnel entry into the Containment, and to maintain the Containment Structure at a specified Containment atmospheric pressure.

The control rod drive mechanism cooling subsystem is designed to induce supply air into the control rod drive mechanism shroud at or below 120°F for cooling.

The RCA Tunnel Exhaust System in conjunction with the RCA Tunnel Heating and Ventilation System maintains the RCA Tunnel pressure.

The safety related portion of the Containment Structure Heating, Cooling, and Purge System is the Containment Structure Recirculation Filter subsystem when operating in a recirculation mode with its filter sections bypassed to provide Containment atmosphere mixing to prevent excessive hydrogen stratification. Containment mixing

to prevent excessive hydrogen stratification after a LOCA, has been evaluated in LAR Subsection 6.1.6, which demonstrates that the current design is acceptable to support SPU operation.

Following implementation of the SPU, the heat load to the Containment Structure Heating, Cooling, and Purge System is expected to increase slightly. This additional heat load is due to the Reactor Coolant Pump horsepower increase (refer to LAR Section 5.8); and also due to the minor increases in heat loads from the NSSS and Feedwater systems. The results of the evaluation demonstrated that the increase due to SPU in the bulk Containment air temperature is less than 1°F and that the calculated Containment bulk air temperature is close to, but within the design temperature of 120°F.

The effect on the Containment Structure filtered exhaust subsystems maintaining offsite and Control Room doses is addressed in FPLE letter NYN-03061, dated October 6, 2003 [Reference 1.1-1] that included a licensing amendment request to the NRC (LAR 03-02) for implementation of Alternative Source Terms.

8.4.14.2.5 CONTAINMENT ENCLOSURE AND ADJOINING AREAS COOLING AND VENTILATION SYSTEM

The Containment Enclosure and Adjoining Areas Cooling and Ventilation System serves multiple areas (Charging Pump areas, Residual Heat Removal equipment areas, Safety Injection Pump areas, Containment Spray equipment areas, Hydrogen Analyzer area, Mechanical Penetration areas, Main Steam and Feedwater Pipe Chases, and ventilation equipment areas with cooling and ventilation for removal of heat generated by lighting and equipment.

Other than the Main Steam and Feedwater Pipe Chases, the other areas were evaluated and determined that the impact of the SPU on them does not adversely affect the operational ability of the systems that serve them. These systems will function as designed under SPU conditions.

The Main Steam and Feedwater Pipe Chases Ventilation System is designed to maintain the east and west pipe chases at a suitable environment for operating equipment. The pipe chases design air temperature at normal operating conditions is 130°F.

The heat loads to the Main Steam and Feedwater Pipe Chases Ventilation system is expected to increase slightly following implementation of the SPU. The heat loads affected by the SPU are due to changes in the operating temperatures of the Main Steam and Feedwater Systems. The results of the evaluation demonstrated that the increase in the bulk air temperature due to the SPU is less than 1°F and that the air handling system can maintain the bulk air temperature less than the design values.

8.4.14.2.6 TURBINE BUILDING HEATING, VENTILATION, AND AIR CONDITIONING SYSTEM

The Turbine Building Heating, Ventilation, and Air Conditioning system is a non safety-related system designed to vent and heat the Turbine Building as necessary to maintain design conditions for equipment operation. In addition, the air handling system is designed to vent and heat the main battery room, radio room, and the battery room located in the relay room. The Turbine Building Heating, Ventilation, and Air Conditioning system also prevents hydrogen gas buildup from exceeding design limitations in the battery rooms.

The design summer maximum air temperature on the ground floor of the Turbine Building is 104°F, 115°F on the Mezzanine floor, and 145°F on the operating floor. The system is not safety related and is not assumed to operate following a postulated design basis accident.

Following implementation of the SPU, the heat load to the Turbine Building Heating, Ventilation, and Air Conditioning system is expected to increase slightly. The additional heat loads are due to changes in the condensate pump horsepower (refer to LAR Subsection 8.4.3) and also due to the minor changes in the heat loads from the Main Steam and Feedwater systems fluid temperatures. The results of the evaluation demonstrated that the increase in the bulk air temperature is less than 1°F and that the Turbine Building Heating, Ventilation, and Air Conditioning system can maintain the bulk air temperature less than the design values.

8.4.14.2.7 ADDITIONAL HEATING, VENTILATION, AND AIR CONDITIONING SYSTEMS

The following additional Heating, Ventilation, and Air Conditioning systems were evaluated. Based on the evaluation, it was confirmed that these systems are not impacted by the heat load additions from the SPU.

- Waste Processing Building Heating, Ventilation and Air Conditioning System
- Electrical Penetration Area Air Conditioning System
- Diesel Generator Building Heating and Ventilation System
- Cable Spreading Room Ventilation System
- 4-KV Switchgear Area, Battery Rooms and Electrical Tunnel Heating and Ventilation Systems
- Emergency Feedwater Pumphouse Heating and Ventilation System
- Administration and Service Building Heating, Ventilation and Air Conditioning System
- Service Water Pumphouse Heating and Ventilation System
- Service Water Cooling Tower Heating and Ventilation System

The impact of the SPU on the additional systems listed above does not adversely affect the operational ability of these systems. These systems will function as

designed under SPU conditions. No equipment or system modifications are required as a result of the SPU.

8.4.14.2.8 EFFECTS OF LOSS OF VENTILATION WITH STATION BLACKOUT

The areas containing equipment required to cope with a Station Blackout were evaluated for the effects of loss of ventilation at SPU conditions. These areas include the Emergency Feedwater Pumphouse, Vital Switchgear Rooms, Battery Rooms, Containment Structure, Main Steam and Feedwater Pipe Chases, Mechanical Penetration Area, Control Room, and the Electrical Tunnels. For all of these areas, the final calculated temperature at the end of the four-hour Station Blackout coping duration was less than the minimum environmental qualification temperature for the equipment located in the area.

The areas evaluated for the effects of loss of ventilation at SPU conditions during a Station Blackout were determined not to be impacted by the SPU.

8.4.14.3 CONCLUSION

The evaluations for each of the Heating, Ventilation, and Air Conditioning Systems identified above demonstrated the current design remains bounded following implementation of the SPU. The Heating, Ventilation, and Air Conditioning Systems following implementation of the SPU will continue to meet the requirements of General Design Criteria 4, 60, and 61.

With regard to radiological consequences, this SPU LAR relies on LAR 03-02 submitted to the NRC by FPLE letter NYN-03061, dated October 6, 2003 [Reference 1.1-1], to adopt alternative source term methodology for the Seabrook Station. The radiological impact of the control building Heating, Ventilation, and Air Conditioning systems at SPU is addressed in this referenced submittal.

Refer to LAR Sections 8.4.15.2.1 and 8.4.15.2.2 for evaluation of effluents and shielding.

The SPU has no impact on the ability of the Heating, Ventilation, and Air Conditioning Systems serving areas containing equipment required to cope with Station Blackout for the effects of loss of ventilation at SPU conditions, which will remain within the equipment qualification temperatures.

8.4.15 RAD WASTE

8.4.15.1 RAD WASTE SYSTEMS

8.4.15.1.1 DESCRIPTION

The liquid rad waste systems (Liquid Waste System, Boron Recovery System, and Steam Generator Blowdown System), the Radioactive Gas Waste System, and the Solid Rad Waste Handling system are described in Seabrook Station UFSAR Sections 11.2, 11.3, and 11.4 respectively. Potentially radioactive liquids, gases,

and solids are collected and processed according to physical and chemical properties and radioactive concentrations as deemed necessary.

8.4.15.1.2 EVALUATION

The flow rates into the liquid and gaseous rad waste systems are not expected to increase for SPU conditions. The evaluation of the liquid, gaseous and solid rad waste systems at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) demonstrated the current design is acceptable to support SPU. The SPU results in slight increases in the equilibrium radioactivity in the reactor coolant. This change in radioactivity of the reactor coolant impacts the concentrations of radioactive nuclides in the rad waste systems. The impact of the increased activity in the rad waste systems is primarily in the activity shipped off-site as solid waste. The rad waste systems design pressures, temperatures and capacities are not impacted by SPU. Refer to LAR Subsection 8.4.15.2 for further discussion of radiological impacts.

8.4.15.1.3 CONCLUSION

The SPU has no significant impact on the rad waste systems or the expected annual rad waste effluent releases/doses. It is therefore concluded that following SPU, the liquid, gaseous, and solid rad waste systems will continue to meet their design functions.

8.4.15.2 RADIOLOGICAL ASSESSMENTS

This section assesses the radiological impact of the SPU at Seabrook Station. The current licensing basis core power level is 3411 MWt. The current 18 month fuel cycle will remain unchanged.

The radiological impact of the SPU was evaluated for the following:

- Normal Operation Annual Rad Waste Effluent Releases
- Post-Accident Access to Vital Areas
- Normal Operation Environmental Levels and Shielding
- Post-Accident Environmental Levels
- Radiation Monitor Setpoints

Note that the impact of the SPU on post accident dose consequences at the site boundary, and at on-site locations requiring continuous occupancy is documented in LAR No. 03-02 which addresses the implementation of Alternative Source Term methodology for Seabrook Station.

The radiological evaluations for Alternate Source Term, accident and normal operation related issues were assessed at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The SPU evaluations discussed in this section are based on development of source term / system operation adjustment factors that reflect the difference between current and SPU operations, and scaling techniques. The radiation source terms utilized in the SPU evaluations take into consideration operation with an 18-month fuel cycle. The estimated increase in radiation environments that are currently based on design analyses, reflect, in addition to the SPU power level, a) the change in fuel cycle length (i.e., current vs that utilized in the design analysis), and b) the use of current computer codes, methodology and nuclear data in developing the SPU core / reactor coolant inventory (vs the methodology, computer tools and nuclear data used in the development of the original licensing basis core / reactor coolant inventory).

8.4.15.2.1 NORMAL OPERATION ANNUAL RADWASTE EFFLUENT RELEASES

DESCRIPTION

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials as discussed below:

Liquid Radioactive Waste: Liquids from reactor process systems, or liquids that have become contaminated with these process system liquids, are considered liquid radioactive waste. These wastes are then processed according to their purity level (boron concentration, conductivity, insoluble solids content, organic content, and activity) before being recycled within the plant, discharged to the environment, or reprocessed through the radioactive waste system for further purification until the dose guidelines of federal regulations are met.

Gaseous Radioactive Waste: Airborne particulates and gases vented from process equipment and the building ventilation exhaust air are considered gaseous radioactive waste. The major source of gaseous radioactive waste is the radioactive gaseous waste system. To ensure that the dose guidelines of Federal regulations are not exceeded, gaseous wastes are continuously decayed using charcoal adsorbers, filtered during operation, and monitored prior to release to the environment.

The liquid and gaseous rad waste systems are designed such that the plant is capable of maintaining normal operation offsite releases and doses within the requirements of 10CFR20 and 10CFR50, Appendix I. (Note that actual performance and operation of installed equipment, and reporting of actual offsite releases and doses continues to be controlled by the requirements of the Offsite Dose Calculation Manual).

The SPU does not change existing radioactive waste systems (gaseous and liquid) design, plant operating procedures, or waste inputs as defined by NUREG 0017. Consequently, a comparison of releases can be made based on current vs SPU inventories / radioactivity concentrations in the reactor coolant and secondary coolant / steam. As a result, the impact of the SPU on rad waste releases and Appendix I doses can be estimated using scaling techniques.

The conservatively performed SPU analysis discussed below, considered the plant core power operating history during the years 1998 to 2002, the reported effluent and dose data during that period, NUREG-0017 equations and assumptions, and conservative methodology, to estimate the impact of operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) over that of current operation, on radioactive effluents and consequent normal operation off-site doses.

EVALUATION

The SPU will increase the activity level of radioactive isotopes in the primary and secondary coolant. Due to leakage or process operations, fractions of these fluids are transported to the liquid and gaseous rad waste systems where they are processed prior to discharge. As the activity levels in the primary and secondary coolant are increased, the activity level of inputs into the rad waste system are proportionately increased. Regulatory guidance relative to methodology to be used to establish whether the rad waste effluent releases from a pressurized water reactor meet the requirements of 10CFR20 and 10CFR50 Appendix I is provided in NUREG-0017, Revision 1.

The methodology used in the NUREG is independent of the fuel cycle length. In determining the nominal coolant activities provided in NUREG-0017, isotopic concentrations from a number of plants and power levels were combined and adjusted to yield a dataset with a resulting range of uncertainty. Adjustment factors were provided in NUREG-0017 to address facilities outside a nominal range in which coolant activities could be used without adjustment. The core power levels addressed for the current and SPU cases are within the range of applicability and input data that were used to develop NUREG-0017.

The Seabrook Station Annual Radioactive Effluent Release Reports for the last five years (1998 – 2002) demonstrate that the current gaseous and liquid rad waste releases from the site are well within the release/dose limits set by 10CFR50, Appendix I. The effect of the SPU on these releases was evaluated to ensure continued operation within regulatory limits.

The licensed reactor core power level during the 1998 to 2002 time frame was 3411 MWt. For the SPU condition, the system parameters utilized in the evaluation reflect the flow rates and coolant masses at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). For the current condition, the evaluation utilizes offsite doses based on an average 5 year set of organ and whole body doses calculated from effluent reports for the years 1998 through 2002 including the associated average annual core power level extrapolated to 100 percent availability (i.e., 3330.5 MWt).

Using the methodology and equations found in NUREG-0017, Revision 1, and based on a comparison of the change in power level and in plant coolant system parameters (e.g., reactor coolant mass, steam generator liquid mass, steam flow rate, reactor coolant letdown flow rate, flow rate to the cation demineralizer, letdown flow rate for boron control, steam generator blowdown flow rate, steam generator

moisture carryover, etc.) for both current and SPU conditions, the maximum potential percentage increase in coolant activity levels due to the SPU, for each chemical group identified in NUREG 0017, was estimated. To estimate an upper bound impact on normal operation off-site doses, the highest factor found for any chemical group pertinent to the release pathway was applied to the average doses previously determined as representative of operation at current conditions. This approach was utilized to determine the maximum average effluent doses due to the SPU, and to demonstrate that the estimated normal operation off-site doses following SPU, although increased, will continue to remain below the regulatory limits.

Expected Reactor Coolant Source Terms

Based on a comparison of current vs. SPU input parameters, and the methodology outlined in NUREG 0017, the maximum expected percentage increase in the reactor coolant source between operation at the effective power level of 3330.5 MWt (based on the 5 year period) to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) is approximately 10.9% for noble gases and 9.9% for other long half life non-gaseous activity. This is primarily due to steam generator tube plugging allowance and increase in the effective core power level (~9.9% - [effective power increase is 3659 MWt/3330.52 MWt {average power level during 1998 – 2002}= 1.099]). Considering the accuracy and error bounds of the operational data utilized in NUREG 0017, this percentage is well within the uncertainty of the existing NUREG 0017 based expected reactor coolant isotopic inventory used for rad waste effluent analyses.

Liquid Effluents

Since the activity levels in the process streams entering the rad waste systems increase in proportion to the increase in primary and secondary coolant activity, the increase in activity level in the liquid effluent will be a maximum 9.9% from the current case (based on the 5 year period), This is valid, since effluent activities are based on the long term reactor coolant activity which is proportional to the effective core uprate percentage increase, and on waste volumes which are essentially independent of power level within the applicability range of NUREG 0017.

Tritium releases in liquid effluents are assumed to increase approximately 9.9% (corresponding to the effective core power SPU percentage increase) since the analysis is identifying changes in an existing facility's power rating without changing normal plant operations.

Gaseous Effluents

For noble gases, there will be a maximum 10.9% increase in effluent releases due to the SPU when compared to the current case (based on the 5 year period). Gaseous effluents have two components, one which is based on reactor coolant inventory and results in a 9.9% increase, and the second which is based on reactor coolant concentration which results in a 10.9% increase (due primarily to decrease in reactor coolant mass (~1%) and increase in core power level (~9.9%) between the current and SPU conditions). With the exception of Kr-85, decay is the dominant removal

mechanism for noble gases in the reactor coolant system. The limiting increase is used for this evaluation, i.e. 10.9%.

In actuality, gaseous releases of Kr-85 will increase by approximately the percentage of power increase (9.9%). Gaseous isotopes with shorter half-lives will have increases slightly greater than the percentage increase in power level up to the bounding value of 10.9%.

For particulates, the methodology of NUREG-0017 specifies the release rate per year per unit per building ventilation system. This is not dependent on power level within the range of applicability. Particulates released via the turbine building from main steam leaks and air ejector exhaust are generally considered to be a small fraction of total particulate releases. Thus, minimal change would be expected for the SPU operations. However, a conservative approach is dictated by the fact that the annual effluent release reports do not delineate the "source" of particulates or iodines released. Therefore, the maximum increase for any part of the release is assumed for the entire category. The multiplier utilized in this case is specifically applicable to the particulates released via the turbine building due to main steam leaks and air ejector exhaust and is higher than the percentage of the SPU (primarily due to an estimated 7 fold increase in moisture carryover due to the SPU, coupled with a 9.9% increase in coolant concentration), but is conservatively used to estimate the impact of the SPU on effluent doses from the particulates and iodines. This is reasonable as the Seabrook Station calculated organ doses for 5 years from iodines and particulates indicate that doses from particulates are comparable to doses from iodines.

Tritium releases in the gaseous effluents increase in proportion to their increased production, which is directly related to core power and is allocated in the same ratio as current releases.

Estimated Impact on Effluent Doses due to the SPU

LAR Table 8.4.15-1, shows that based on operating history, the maximum estimated dose following SPU is significantly below the 10CFR50 Appendix I limits as well as below those presented as part of the original license in the Seabrook Station Final Environmental Statement.

Solid Radioactive Waste

Though solid rad waste is not specifically addressed in 10CFR50, Appendix I, for completeness relative to rad waste assessments, the impact of the SPU on solid rad waste generation is summarized below.

For a "new" facility, the estimated volume and activity of solid waste is linearly related to the core power level. However, for an existing facility that is undergoing power uprate, the volume of solid waste would not be expected to increase proportionally, since the SPU neither appreciably impacts installed equipment performance, nor does it require drastic changes in system operation or maintenance. Only minor, if any, changes in waste generation volume are expected. However, it is expected that

the activity levels for most of the solid waste would increase proportionately to the increase in long half-life coolant activity bounded by the effective increase in core power level.

Thus while the total long lived activity contained in the waste is expected to be bounded by the effective core power level increase percentage of 9.9%, the increase in the overall volume of waste generation resulting from the SPU is expected to be minor.

CONCLUSION

The estimated doses due to annual rad waste effluent releases following implementation of the SPU will remain a small percentage of the allowable 10 CFR 50 Appendix I limits. Also, following the SPU, the liquid and gaseous rad waste effluent treatment system will remain capable of maintaining normal operation offsite doses within the requirements of 10 CFR 50, Appendix I.

8.4.15.2.2 POST ACCIDENT ACCESS TO VITAL AREAS

DESCRIPTION

In accordance with NUREG 0737, II.B.2, vital areas are those areas within the station that will or may require access / occupancy to support accident mitigation or recovery following a Loss of Coolant Accident (LOCA). In accordance with the above regulatory document, vital areas and access routes to vital areas, must be designed such that operator exposure remains within regulatory limits.

Seabrook Station UFSAR Section 12.3.2.2 describes the assessment performed in support of post accident vital area access and compliance with NUREG 0737 II.B.2. It notes that the referenced assessment was incorporated in the Post-Accident Dose Engineering Manual which is used for planning for post accident operations, and that a copy of the manual was provided to the NRC [Reference 8.4-2].

This section focuses on areas that may require short term, one-time or infrequent access following a LOCA. On-site locations that require continuous occupancy and a demonstration of 30-day habitability are addressed in Licensing Amendment Request No. 03-02. Licensing Amendment Request No. 03-02 addressed the implementation of Alternative Source Terms for Seabrook Station with regard to assessment of dose consequences at the site boundary and control room at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) [Reference 8.4-1].

Table 2.2-1 of the Basis for Post-Accident Dose Engineering Manual, identifies seven (7) areas that were determined to require infrequent access following a LOCA, and provides a basis for why four additional (4) areas, that are identified or implied in NUREG-0737 II.B2 as areas that potentially could require occasional access, are not applicable to Seabrook Station. Of the seven (7) areas that require infrequent access following a LOCA, two are located in the control room, therefore, by definition are accessible throughout the 30-day LOCA.

Dose rates and operator doses provided in the Basis for Post-Accident Dose Engineering Manual reflect both a pressurized and a depressurized LOCA scenario for an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and a traditional 12-month fuel cycle length.

The SPU impacts the equilibrium core inventory and therefore the post accident radiological source terms. Additional factors that can impact the equilibrium core inventory are fuel enrichment and burnup.

As discussed earlier, Seabrook Station is currently also going forward with the implementation of Alternative Source Terms as outlined in 10CFR50.67 and Regulatory Guide 1.183, for post-accident dose assessments associated with the site boundary, and on-site locations that require continuous occupancy such as the control room. However, for the reasons summarized in SECY-98-154, the SPU assessment for purposes of evaluating the impact on operator exposure while performing vital functions in areas that require infrequent access is based on TID 14844 source terms. The AST bench marking study reported in SECY-98-154 concluded that results of analyses based on TID 14844 would be more limiting earlier on in the event, after which time the AST results would be more limiting. Post-LOCA access to vital areas for purposes of accident mitigation and safe shutdown occurs earlier on in the event when the original TID 14844 source term is more limiting.

EVALUATION

The impact of the SPU on the post-LOCA gamma radiation dose rates was evaluated by comparing the gamma source terms based on the original core inventory used to develop the post LOCA dose rates, to the gamma source terms based on the SPU core inventory. This approach takes into consideration that a) the post-LOCA operator mission requirements, including the task description and required time / duration for access is not impacted by the SPU, and b) SPU does not impact the operation and layout / arrangement of plant radioactive systems.

The SPU will increase the activity level in the core by the percentage of the uprate. The estimated radiation source terms in equipment / structures containing post accident fluids, and the corresponding post LOCA environmental dose rates, will increase by the percentage of the uprate relative to the power level used in the analyses of record. Additional factors that will impact the equilibrium core inventory and consequently, the estimated operator dose are fuel enrichment and burnup. Following SPU, the post-LOCA environmental gamma dose rates, and the operator dose per identified mission, should increase by approximately 2.64% (3659 MWt / 3565 MWt).

However, because the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) reflects: (a) operation with a 18-month fuel cycle; and (b) more advanced fuel burnup modeling/libraries than used in the original analyses, the calculated SPU scaling factor values deviate from the core power ratio.

The SPU assessment is essentially a two-step process. The first develops a bounding SPU dose rate scaling factor, and the second multiplies the current personnel dose /dose rates at target areas identified in the licensing basis, by the bounding SPU scaling factor.

The current and the SPU core inventories are utilized to develop the post-LOCA gamma energy release rates (Mev/sec) per energy group vs. time, for containment atmosphere, sump water, and pressurized recirculating fluid.

For the "unshielded" case, the factor impact on post-accident gamma dose rates was estimated by ratioing the gamma energy release rates weighted by dose rates, as a function of time, for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), to the corresponding weighted source terms based on the current analyzed core power level. To address the fact that the vital access locations are outside containment, the unshielded values included the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This ensures that the results are not skewed by photons at energies less than 25 kev which will be substantially attenuated by any piping sources.

To evaluate the factor impact of the SPU on post-LOCA gamma dose rates (vs. time) in areas that are "shielded," the current as well as the SPU source terms discussed above were weighted by the concrete reduction factors for each energy group. The concrete reduction factors for 1 and 3 feet of concrete were used to provide a basis for comparison of the post LOCA spectrum hardness of source terms, with respect to time, for both original design and SPU cases, for lightly shielded and heavily shielded cases.

Since the SPU gamma dose rate scaling factors will vary with source, as well as shielding, the maximum dose rate scaling factor developed from the above assessments was used, for the source/receptor combinations, with or without shields, for the time period identified in the vital access assessment.

The SPU scaling factors for Vital Access Dose Rates vary from 0.97 to 1.11, and 0.97 to 1.12, for the pressurized and de-pressurized LOCA, respectively. LAR Table 8.4.15-2 presents the vital area access dose estimates following the SPU.

CONCLUSION

It is concluded that following implementation of the SPU, the post LOCA vital area operator dose estimates will remain within the regulatory limit of 5 Rem whole body listed in NUREG 0737 II.B.2.

8.4.15.2.3 NORMAL OPERATION DOSE RATES AND SHIELDING

DESCRIPTION

Cubicle wall thickness is specified not only for structural and separation requirements, but also, to provide radiation shielding in support of radiological equipment qualification, and to reduce operator exposure during plant operation, including maintenance and accidents. The shielding design basis is discussed in

Seabrook Station UFSAR Sections 12.2 and 12.3. The SPU assessment demonstrates that the current shielding design is acceptable to support SPU operation.

Conservative estimates of the radiation sources in plant systems and personnel access requirements form the bases of normal operation plant shielding and radiation zoning. These radiation source terms are primarily derived from conservative estimates of the reactor core and reactor coolant (also called primary coolant) isotopic inventory and are referred to as design basis source terms. SPU will impact the isotopic inventory in the core. In addition, since the design basis reactor coolant source term is based on 1% fuel defects, the SPU will result in an increase in the design basis reactor coolant concentration.

The expected radiation source terms in the coolant will also be impacted by the SPU. Expected source terms are less than that allowable by the plant Technical Specifications and are usually significantly less than the design basis source terms.

The impact of the SPU on the normal operation dose rates, and the adequacy of existing shielding, was evaluated to ensure continued safe operation within regulatory limits. This section also discusses the impact of the SPU on the normal operation component of the total integrated dose used for radiological environmental qualification.

EVALUATION

The SPU will increase the activity inventory of fission products in the core by approximately the percentage of the SPU. The radioactivity levels in the primary coolant, secondary coolant, and other radioactive process systems and components will also be impacted.

As documented in Seabrook Station UFSAR Sections 12.2 and 12.3, the plant shielding design is based on a core power level of 3654 MWt, a traditional one year fuel cycle and a design reactor coolant system source term based on 1% fuel defects.

The SPU core inventory is based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and an 18-month fuel cycle. The SPU design reactor coolant source term is based on 3659 MWt / 1% fuel defects and an 18-month fuel cycle. The inclusion of the 18-month fuel cycle increases the inventory of the long-lived isotopes.

The SPU normal operation dose rates and shielding assessment is based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The assessment is broken into three parts, i.e., the impact of SPU on: a) plant radiation levels during normal operation (note that this portion of the assessment takes into consideration that the current in-plant radiation levels, as experienced by the operators, already reflect the 18 month fuel cycle), b) adequacy of existing shielding for normal plant operation, and c) 40 year normal operation doses utilized for equipment qualification.

Plant Radiation Levels during Normal Operation

For the same source-shield-detector configuration, the dose rate at a given detector point is directly proportional to the neutron/gamma flux leaking out of the source region or the volumetric gamma source strength in the source region. This flux or activity increase factor for a given radiation source is the SPU scaling factor for the expected dose rate due to that source.

The SPU assessment with regard to normal operation radiation levels is divided into four parts.

Areas near Reactor Vessel: During normal operation, the radiation source in the reactor core is made up of neutron and gamma fluxes, which are approximately proportional to the core power level. The radiation sources during shutdown are the decayed gamma source in the core and the activation activities in the reactor internals, pressure vessel/head, and primary system piping walls, which also vary approximately in proportion to the reactor power. Operation with an 18-month fuel cycle will increase the long-lived isotopes in the reactor core but has insignificant impact to the normal operation dose rate in areas near the reactor vessel. An uprate from the current licensed core power of 3411 MWt to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) is expected to increase the normal operation radiation levels in areas near the reactor vessel by a factor of approximately 1.07.

In-Containment Areas Adjacent to the Reactor Coolant System: During normal operation, the major radiation source in the reactor coolant system components located within containment is the high-energy gamma emitter Nitrogen-16 (N-16). N-16 is produced as the oxygen (of the water moderator) is exposed to the fast neutron flux present in the reactor core. The amount of activation is defined by the fast flux level of the core and the amount of time the moderator is resident in the core. After the moderator exits the core, decay of the N-16 will occur. The amount of decay at any given point in the coolant loop is defined by the time subsequent to exiting the core. The fuel cycle length has no impact on the inventory of the short-lived N-16 source. During shutdown, the major radiation sources in the reactor coolant system components located within containment are the deposited corrosion products on the internal surfaces and the primary coolant activity without N-16. With the core power increase from 3411 MWt to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), the fast neutron flux is expected to increase by approximately 7%. The coolant residence time in the core and the transit time in the loop will not change significantly due to the SPU. (See LAR Section 4.1). Therefore, the appropriate SPU scaling factor for the areas subjected to the N-16 source is 1.07.

Areas near Irradiated Fuels and Other Irradiated Objects: These areas include the refueling canal, spent fuel pool, incore instrumentation drive

assembly area, and other areas housing neutron irradiated materials. The radiation source is the decay gammas from the fission products and activation products, which are determined by the fission rate, neutron flux level and the irradiation time. The 18-month fuel cycle will increase the long-lived isotopes in the irradiated fuel. However, this is not a significant concern as the dose rates near the refueling canal and the spent fuel pool are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies. Since both the fission products and the activation products are expected to increase by approximately 7% for a core power increase from 3411 MWt to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), the SPU scaling factor for the areas subjected to irradiated fuels and other irradiated sources is 1.07.

Areas Outside Containment where the Radiation Source Is Derived from the Primary Coolant Activity: In most areas outside the Reactor Containment the radiation sources are either the primary coolant itself or down-stream sources originating from the primary coolant activity. The reactor coolant activity is dominated by the fission product, which leaks from the core via clad defects and varies approximately in proportion to the reactor power. The neutron activated corrosion products (Co-60, Co-58, etc.) are also important radionuclides in the filters. The deposited activity of corrosion products on pipe internal surfaces is a major dose contributor during shutdown maintenance. The deposited corrosion product activity depends on the reactor coolant chemistry, the cobalt impurity in the reactor coolant system piping, in addition to the neutron flux level in the core. With the core power level being the only change, the corrosion product concentration and the equilibrium deposited corrosion product in the reactor coolant system are expected to increase by approximately the same percentage of the uprate due to the increased neutron flux level. Since both the fission products and the activated corrosion products are expected to increase by approximately 7% for a core power increase from 3411 MWt to the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), the SPU scaling factor of 1.07 is applicable for the areas outside containment where the radiation source is derived from the reactor coolant activity. This takes into consideration that the in-plant radiation levels, as experienced by the operators, already reflect the 18 month fuel cycle.

Adequacy of Existing Shielding for Normal Operation

Reactor Primary Shield: The function of the primary shield is to attenuate the neutron and gamma fluxes leaking out of the reactor vessel.

The SPU assessment takes into consideration that the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) will increase the currently observed dose rate outside the primary shield by approximately the percentage of the uprate, i.e., 7%. Operation with an 18-month fuel cycle has insignificant impact on the normal operation dose rate in areas near the

reactor vessel. Credit is taken for the fact that the plant has been successfully operated at the current licensed power level for more than 13 years with no known inadequacy in the primary shield. Credit is also taken for the conservative analytical techniques used to establish plant shielding design. It is concluded that the primary shield wall remains adequate for SPU.

Reactor Secondary Shield: The primary function of the reactor secondary shield is to attenuate the N-16 source in the reactor coolant system which emits high-energy gammas. The design basis reactor coolant N-16 activity utilized for design of the reactor secondary shield is based on a reactor power of 3565 MWt. The fuel cycle length has no impact on the inventory of the short-lived N-16 source. The analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) represents an increase in the design N-16 source by 2.6 %. Taking into consideration the conservative analytical techniques used to establish plant shielding design, the current secondary shield is acceptable for continued safe operation following SPU.

Spent Fuel Shielding: This shielding provides protection during spent fuel removal and storage. The design basis spent fuel source term utilized for shield design is based on a reactor power of 3565 MWt. The analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) represents an increase in the design spent fuel source by approximately 2.6 %. The impact of 18-month fuel cycle is not significant because the source is dominated by isotopes with shorter half-lifes. Taking into consideration the conservative analytical techniques used to establish plant shielding design, the current spent fuel shielding is acceptable for continued safe operation following SPU.

Shielding Outside Containment: In support of shielding provided outside the containment, where most of the radiation sources are either the reactor coolant itself or down-stream sources originating from coolant activity, a review was performed of the design primary coolant source terms utilized for the SPU vs. the original design basis primary coolant source terms. It is noted that the analyzed design primary coolant source terms utilized for the SPU reflect an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), operation with an 18-month fuel cycle, and more advanced fuel burn-up modeling/libraries as compared to the computer codes used in the original analyses.

A comparison was performed of the gamma energy emission rates by energy group, for the SPU vs. original primary coolant source terms. Three source terms were considered: total primary coolant source, degassed primary coolant source, and the noble gas source in the primary coolant. A comparison of the dose rates resulting from the above three categories of source terms was also performed. The dose rates in a water medium (12 inches ID pipe) and in an air medium were calculated for cases with no shielding, and cases with 1 ft, 2 ft and 3 ft standard concrete shielding. The

comparison showed that the ratio of calculated dose rate for the SPU design primary coolant source to that for the original design primary coolant source varied from 0.81 to 2.1, depending on the source and shield combination.

However, since, the analyzed design basis SPU primary coolant activity is a very conservative source term (i.e., based on 1% fuel defects), the SPU assessment took credit for a more realistic but limiting upper bound primary coolant activity based on the Seabrook Station Technical Specification No. 3.4.8. The SPU evaluation demonstrated that the original design basis source term is conservative with respect to the SPU source term for the noble gases in the reactor coolant, and that the maximum dose rate increase factor due to the design basis SPU "total" reactor coolant and "degassed" reactor coolant source term of 2.1 was bounded by the Technical Specifications that effectively limits the reactor coolant non-gaseous activity levels to concentrations that are a factor of 3.2 less than design.

Therefore, taking into consideration the limits on reactor coolant concentrations imposed by the Seabrook Station Technical Specifications, it was concluded that the shielding design based on the original design basis primary coolant activity remains valid at the SPU conditions.

40 Year Normal Operation Doses utilized for Environmental Qualification

The 40-year normal operating doses utilized for environmental qualification of safety related equipment were evaluated for the SPU and operation with an 18 month fuel cycle.

For most areas inside the Containment Structure, the original normal operation dose estimates for Seabrook Station are based on a reactor power of 4100 MWt.

The normal operation dose estimates in areas between the missile shield and reactor primary shield, and around reactor coolant piping penetrations in the primary shield are based on a reactor power of 3565 MWt. This portion of the SPU radiological evaluation takes into consideration that prior to the SPU, the station has operated at a power level of not more than 3411 MWt.

For areas outside the containment with radiation sources, the normal operation dose estimates are based on a reactor power of 3654 MWt and 0.2% fuel defects. This portion of the SPU radiological evaluation also takes into consideration that prior to the SPU, the station has operated at a power level of not more than 3411 MWt. No credit is taken for reduced fuel defects expected during normal operations (Seabrook Station UFSAR Table 11.1-1 indicates that the expected fuel defects are 0.12%, whereas the existing environmental dose analyses conservatively assume 0.2% fuel defects).

For areas outside the containment without radiation sources, the normal operation doses are based on the radiation zone dose rate limits which are not impacted by the SPU.

Except as noted below, the SPU assessment concluded that the current 40-year normal operation dose estimates remain valid for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The normal operation radiation environmental level for equipment qualification in selected areas outside containment where the existing radiation environmental levels are based on a core power level of 3654 MWt and 0.2% fuel defects, are conservatively increased by a factor of 1.7. This approach allows retention of the existing conservatism in the source terms / fuel defect assumptions utilized in the supporting analyses.

CONCLUSION

The increase in radiation levels due to the SPU (expected to be the same as percentage increase in power level associated with the SPU) will not significantly affect radiation zoning or shielding requirements in the various areas of the plant because it is offset by:

- conservative analytical techniques used to establish original shielding requirements / design,
- conservatism in the current design basis reactor coolant source terms used to establish the radiation zones, and
- Seabrook Station Technical Specifications that limit the reactor coolant concentrations to levels well below (about a factor of 3) the design basis source terms.

Regardless, individual worker exposures will be maintained within acceptable limits by the site ALARA program which controls access to radiation areas.

The SPU evaluation concludes that following implementation of the SPU, normal operation dose rates and available shielding will continue to meet the requirements of 10CFR20 related to allowable operator exposure and access control, and that occupational radiation exposures will be maintained as low as reasonably achievable.

The SPU assessment concluded that, with the exception of selected areas outside containment, the current 40-year normal operation dose estimates are unchanged for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level). The impact of SPU on the normal operation radiation environments is factored into the Equipment Qualification program in accordance with 10 CFR 50.49. The evaluation of the impact of the SPU radiation service conditions on the function/attributes associated with electrical equipment qualification and the ability of the existing equipment to survive the SPU environmental conditions is discussed in LAR Section 9.2.

8.4.15.2.4 POST ACCIDENT ENVIRONMENTAL LEVELS

DESCRIPTION

In accordance with 10CFR50.49 safety-related electrical equipment must be qualified to survive the radiation environment at their specific location during normal operation and during an accident. The environmental design of electrical equipment is addressed in Seabrook Station UFSAR Section 3.11.

The impact of SPU on the current post accident radiation service conditions is discussed in this section. The evaluation of the impact of the SPU radiation service conditions on the function/attributes associated with electrical equipment qualification and the ability of the existing equipment to survive the SPU environmental conditions is discussed in LAR Section 9.2.

For purposes of equipment qualification, Seabrook Station is divided into various environmental zones. The radiological environmental conditions noted for these zones are the maximum conditions expected to occur and are representative of the whole zone.

With the exception of the Fuel Building filter cubicle which is based on a fuel handling accident and is integrated over 30 days, the post-accident radiation levels for each of the environmental zones are determined based on a one-year exposure period following a Loss of Coolant Accident. Two cases are addressed, a pressurized Loss of Coolant Accident and a depressurized Loss of Coolant Accident. The radiation levels outside containment, which would occur as a result of a High Energy Line Break, are considered to be bounded by the radiation levels resulting from recirculating fluids following a Loss of Coolant Accident.

The current zone specific post-accident environmental doses are based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level), a traditional 12 month fuel cycle length, TID 14844 source terms and related guidance documents, and plant specific mitigation system design features/layout. SPU will impact the equilibrium core inventory and therefore the post-accident radiological source terms. Additional factors that impact the SPU equilibrium core inventory are fuel enrichment and burnup. Changes in the radiation source terms will impact the corresponding radiation zone doses.

Seabrook Station has submitted Licensing Amendment Request No 03-02 [Reference 8.4-1] for the implementation of Alternative Source Terms (AST) as outlined in 10 CFR 50.67 and Regulatory Guide 1.183 for the Exclusion Area Boundary, Low Population Zone and the Control Room. As documented in Licensing Amendment Request No. 03-02 and summarized below, the SPU assessment for post accident environmental qualification associated with the Loss of Coolant accident is based on the TID 14844 source terms.

This approach is acceptable based on Section 1.3.5 of Regulatory Guide 1.183 which indicates that although environmental qualification analyses impacted by plant modifications should be updated to address the impacts, no plant modification is

required to address the impact of the difference in source term characteristics (i.e., AST vs TID 14844) on environmental qualification doses. The NRC staff is assessing the effect of increased cesium releases (associated with AST methodology) on environmental qualification doses as a generic safety issue. Pending resolution of this issue, licensees may use either the AST or TID 14844 assumptions for performing the required environmental qualification analyses.

EVALUATION

The impact of SPU on the environmental doses resulting from the design basis Loss of Coolant Accident was evaluated by comparing the source terms based on the original core inventory used to develop the environmental doses, to the source terms based on the SPU core inventory. Since the relative abundance of each isotope and the average energy of each isotope are the key parameters that effect direct exposure, having a scaling factor that addresses the change in these parameters is sufficient to assess the radiological impact of SPU and use of fuel with extended burn-up. This approach takes into consideration that the SPU will not impact operation and layout/arrangement of plant radioactive systems.

The SPU assessment is based on an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) and use of an 18-month fuel cycle. The accident environmental doses should increase by approximately 2.64% (i.e., 3659 [analyzed power level for the SPU] / 3565 [power level used in current calculations]). However, because the core inventory utilized for the SPU reflects: (a) extended burnup; and (b) the more advanced fuel burnup modeling/libraries utilized in development of the SPU core, as compared to the computer code used in the original analyses, the calculated SPU scaling factor values deviate from the core power ratio.

The core inventories associated with the current and the SPU cases were utilized to develop the current and SPU gamma energy release (Mev-hr/sec) per energy group vs. time, for containment atmosphere, sump water, halogens deposited on filters, and pressurized recirculating fluid following the design basis Loss of Coolant Accident.

For the "unshielded" airborne case inside containment (detector immersed in source), the factor impact on post-accident gamma doses was estimated by ratioing the gamma energy release weighted by the flux to dose rate conversion factor, as a function of time, for the SPU analyzed power level, to the corresponding weighted source terms based on the current power level. When the evaluation was performed for the "unshielded" water source (detector immersed in source), the effect for self absorption was addressed.

The in-containment beta dose scaling factors were developed by ratioing the integrated beta dose rates developed using average beta energies and infinite cloud model equations for airborne and waterborne sources, for both the current and the SPU cases.

To address environmental zones outside the containment, the gamma scaling factors for the "unshielded" case included the shielding effect of a pipe wall thickness

associated with a 2-inch. nominal diameter pipe. This insured that the results were not skewed by photons at energies less than 25 kev which will be substantially attenuated by any piping sources. To evaluate the factor impact in areas that are shielded, the current as well as SPU source terms discussed above were weighted by the concrete reduction factors for each energy group. The concrete reduction factors for 1 and 3 feet of concrete were used to provide a basis for comparison of the post accident spectrum hardness of source terms, with respect to time, for both original design and SPU cases, for lightly shielded and heavily shielded cases.

Since the SPU gamma dose scaling factors will vary with source, time, as well as shielding, the maximum dose scaling factor developed for the 1 year time period after the loss of coolant accident, from the above assessments was used, for the source/receptor combinations, with or without shields. In a few cases, a worst-case, location-specific scaling factor was used.

The SPU assessment determined the following post-accident integrated dose scaling factors:

Gamma Doses: The bounding SPU 1-year integrated gamma dose scaling factor applicable to the source/receptor/shielding combinations was 1.2 for a depressurized Loss of Coolant Accident, and 1.19 for a pressurized Loss of Coolant Accident.

Beta Doses: For the depressurized Loss of Coolant Accident, the containment atmosphere activity 1-year integrated beta dose scaling factor and the sump water 1-year integrated beta dose scaling factors were 1.1 and 1.4, respectively. The reactor coolant 1-year integrated beta dose scaling factor for a pressurized Loss of Coolant Accident was 1.34.

The current post-accident dose information utilized for environmental qualification outside containment reflect the "pressurized" or de-pressurized Loss of Coolant Accident, which ever is considered to be appropriate or bounding. In addition, the dose is usually a result of contribution from various different sources (i.e., containment atmosphere, recirculating fluid, etc.). Since the SPU gamma dose scaling factors vary with source, time, as well as shielding, the maximum dose scaling factor of 1.2 was used for purposes of developing the SPU gamma environmental doses in the zones outside containment, for both the pressurized as well as the depressurized Loss of Coolant Accident scenarios. As discussed earlier, in a few cases, a worst-case, location-specific scaling factor was used.

With regard to the post accident environmental levels in the Fuel Building filter cubicle which is based on a fuel handling accident and is integrated over 30 days, it was determined that the current estimates bound the SPU since the SPU Fuel Handling Accident halogen activity is essentially the same as the halogen activity conservatively used in analysis of record.

CONCLUSION

The post accident environmental dose assessment for the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) takes into consideration the impact of the SPU using scaling techniques and TID 14844 source terms. The bounding scaling factors developed reflect the increase in power level as well as the impact of a) the use of an 18 month fuel cycle and b) the more advanced burnup modeling and radionuclide libraries utilized in the development of the SPU core inventory as compared to the computer code used in the original analyses.

The impact of SPU on the accident radiation environments is factored into the Equipment Qualification program in accordance with 10 CFR 50.49. The evaluation of the impact of the SPU radiation service conditions on the function/attributes associated with electrical equipment qualification and the ability of the existing equipment to survive the SPU environmental conditions is discussed in LAR Section 9.2.

8.4.15.2.5 RADIATION MONITOR SETPOINTS

The Radiation Monitoring System is discussed in Seabrook Station UFSAR Sections 11.5 and 12.3.4.

The SPU will increase the activity level of radioactive isotopes in the reactor core, spent fuel, reactor primary and secondary coolant systems, and associated process and waste systems. The referenced increase in radioactivity levels in plant systems / components, and the associated increase of radiation levels in adjacent areas, is estimated to be approximately the percentage increase in reactor power. The relative isotopic compositions in the process and effluent streams are not expected to change due to SPU.

The current setpoint basis for the Radiation Data Management System monitors is described in plant procedures. These procedures were examined to evaluate whether the increase in magnitude of radioactivity levels in process streams, and the corresponding increase in background radiation levels, resulting from the SPU, could impact the radiation monitor setpoint basis, or its value, as determined by the current operating procedures.

It was determined that the basis of the Radiation Data Management System monitor setpoints are either a regulatory commitment, a multiple of the background, or a value indicating an unusual event (such as leakage or malfunction of systems), that leads to a sudden increase of the activity level in the monitored stream. The setpoint values are established using plant operating data and are reviewed frequently and adjusted as required.

The SPU evaluation shows that all of the radiation monitor setpoint bases, and methods of setpoint determination, continue to be valid at the SPU conditions.

8.4.16 ELECTRICAL

8.4.16.1 AC DISTRIBUTION SYSTEM

8.4.16.1.1 DESCRIPTION

The AC Distribution System is a part of the AC Onsite Power Systems discussed in Seabrook Station UFSAR Section 8.3.1. The AC Distribution System is the source of power to non-safety-related buses, and to safety-related emergency buses supplying the redundant engineered safety features loads. It consists of the 13,800 V System, the 4160 V System (not including the emergency diesel generators), and the 480 V System. The emergency diesel generators and auxiliaries are reviewed in LAR Subsection 8.4.16.5. Evaluation of the impact of SPU operation on the AC Distribution System demonstrates that the system and equipment performance, capacity and capability are adequate to support plant operation at SPU conditions, and continue to perform their intended functions.

8.4.16.1.2 EVALUATION

To determine the impact of SPU operation on the AC Distribution System, a baseline for bus loading was developed to represent the "present" plant loading conditions. A load flow/voltage profile system analysis and a short circuit current system analysis that included load changes as a result of SPU conditions were performed. The results of these analyses are used to ensure the functionality of the AC Distribution System for operation at SPU conditions. Specifically, the following items were evaluated:

1. Switchgear bus and circuit breaker, and nonsegregated phase bus duct
   - The calculated worst case continuous current value for each 13,800 V or 4160 V switchgear bus, incoming breaker and nonsegregated phase bus duct, during maximum full load at SPU conditions, is less than the equipment design ratings. Therefore, the loading requirements of switchgear buses, incoming breakers and nonsegregated phase bus ducts are bounded by equipment design ratings at SPU conditions.
   - The calculated full load current value for each affected motor during maximum full load at SPU conditions is less than the breaker design rating. Therefore, the loading requirements for motor feeder breakers are bounded by equipment design ratings at SPU conditions.
   - The calculated short circuit current values (interrupting and momentary) for each 13,800 V or 4160 V switchgear bus and breaker during maximum full load at SPU conditions are less than the equipment short circuit ratings, as indicated in LAR Table 8.4.16-1. Therefore, the fault duty requirements of switchgear buses and breakers are bounded by equipment design ratings at SPU conditions.

LAR Table 8.4.16-4 summarizes the incremental load for each affected pump motor drive, and impact on associated switchgear bus loading.

2. 480 V System equipment

   The 480 V System includes unit substation transformers, switchgears, and motor control centers.

   SPU operation does not affect the existing 480 V System load requirements. Therefore, the existing unit substation transformers, switchgears, and motor control centers are adequately rated to support plant operation at SPU conditions.

3. System Voltage Level

   - Motor terminal voltage values for running reactor coolant pump, condensate pump and heater drain pump motor drives at SPU conditions, during steady-state maximum full load conditions, are provided in LAR Table 8.4.16-2. The table indicates that each running motor terminal voltage is above the minimum required voltage. In addition, the voltage on each of the 4160 V emergency Buses (E5 and E6) that supply the redundant engineered safety features loads is greater than or equal to the degraded voltage relay reset setpoint. Therefore, the minimum steady-state voltages associated with the 13,800 V and 4160 V Systems are not adversely affected by SPU operation. Also, the minimum steady-state voltages associated with the 480 V System (supplied by the 4160 V System) are not adversely affected by SPU operation.

   - Motor terminal voltage values for starting reactor coolant pump and condensate pump motor drives at SPU conditions, during maximum full load conditions, are provided in LAR Table 8.4.16-3. The table indicates that each starting motor terminal voltage is above the minimum required voltage, and that motor terminal voltages for the other running motors (on the same bus) are above the minimum required voltage. Therefore, motor starting terminal voltages are not adversely affected by SPU operation.

4. Motor Load Requirements

   The reactor coolant pump, condensate pump and heater drain pump motor drives are affected by plant operation at SPU conditions, as indicated in LAR Table 8.4.16-4.

   - Motor Operating Capability

     Westinghouse evaluated in LAR Section 5.8 the reactor coolant pump motors for operation at hot-loop and cold-loop temperatures and flows during operation at SPU conditions, and brake horsepower requirements. Westinghouse determined that motor operation is not adversely affected by SPU conditions, because the winding temperature rise does not exceed the value specified in the NEMA Standard.

Brake horsepower requirements for the condensate pump and heater drain pump motor drives at SPU conditions are discussed in LAR Subsections 8.4.3 and 8.4.8, respectively, and determined to be within motor nameplate ratings.

- The calculated full-load current values for reactor coolant pump, condensate pump and heater drain pump motor drives at SPU conditions, and the derated ampacities for associated motor feeder cables and electrical penetrations (as applicable) are provided in LAR Table 8.4.16 -5. The table indicates that for each affected pump motor drive, the calculated motor full-load current does not exceed the derated ampacities of motor feeder cable and electrical penetrations. Therefore, the motor feeder cable and electrical penetration requirements at SPU conditions are bounded by the existing design ratings.
- Existing protective relay settings of the reactor coolant pump motor drives were evaluated as follows, using the SPU requirements:
  - Protective relay settings (including underfrequency and undervoltage) were reviewed and determined not impacted by SPU conditions.
  - Under the postulated operating conditions, including maximum load of one of the 13,800 V buses (2 reactor coolant pumps, 2 circulating water pumps, and the 13,800 V substations) and minimum bus voltage, failure of one reactor coolant pump (with incipient locked rotor amps) does not result in tripping of the incoming breaker to the 13,800 V bus.
- Existing protective relay settings of the condensate pump and heater drain pump motor drives were reviewed, using the SPU requirements, and determined to be unaffected at SPU conditions.

5. General Design Criteria 17 Requirements

   The load flow/voltage profile system analysis and short circuit current system analysis indicate that the AC Distribution System equipment voltages and fault duties are not adversely affected by SPU conditions, when powered from the offsite power sources (unit and reserve auxiliary transformers). Also, the loading requirements of switchgear buses and circuit breakers, nonsegregated phase bus ducts, unit substation transformers, and motor control centers are bounded by equipment design ratings. Therefore, the AC Distribution System will continue to meet the General Design Criteria 17 requirements, and perform their intended functions during plant operating and accident conditions, following implementation of the proposed SPU.

8.4.16.1.3 CONCLUSION

1. Switchgear Bus and Breaker, and Nonsegregated Phase Bus Duct

- Loading requirements of switchgear buses and circuit breakers, and nonsegregated phase bus ducts are bounded by equipment design ratings at SPU conditions.
- Short circuit current requirements of switchgear buses and circuit breakers are bounded by equipment design ratings at SPU conditions.

2. 480 V System Equipment

   The existing unit substation transformers, switchgears, and motor control centers are adequately rated to support plant operation at SPU conditions.

3. System Voltage Level

   The minimum steady-state motor terminal voltages and motor starting voltages for affected pump motor drives are not adversely impacted by SPU conditions.

4. Motor Load Requirements

   - Reactor coolant pump motor drives are not adversely affected by SPU operation (LAR Section 5.8).
   - Condensate pump and heater drain pump motor drives will operate within motor nameplate rating at SPU conditions (LAR Subsections 8.4.3 and 8.4.8).
   - The associated motor feeder cables and electrical penetrations are adequately sized and bounded by the existing design ratings.
   - The protective relay settings of affected pump motor drives are not impacted by SPU operation.

5. General Design Criteria 17 Requirements

   The proposed SPU does not have any adverse impact on the AC Distribution System's functional design. Therefore, the AC Distribution System will continue to meet the requirements of General Design Criteria 17 following implementation of the proposed SPU.

8.4.16.2 POWER BLOCK ELECTRICAL EQUIPMENT

8.4.16.2.1 DESCRIPTION

The Power Block Equipment is described in Seabrook Station UFSAR Section 8.2.1.3. The evaluation of the main generator, generator step-up transformers, unit auxiliary transformers, reserve auxiliary transformers, isolated phase bus duct and generator circuit breaker demonstrates that the current design of the system and equipment is adequate to support SPU operation.

The main generator is rated 1350 MVA, 25 KV, 60 HZ, 0.92 power factor, 1800 rpm at 75 psig hydrogen pressure, with a water-cooled stator. The output of the main generator is delivered to the low voltage windings of three single-phase Generator Step-up Transformers via the main isolated phase bus duct. An isolated phase bus tap bus connects the main generator output to the Unit Auxiliary Transformers.

The generator circuit breaker is located between the generator output terminals and the isolated phase bus tap to the generator step-up transformers and unit auxiliary transformers. The generator step-up transformers and unit auxiliary transformers form part of the immediate access circuit from the preferred (offsite) power supply to the onsite distribution system when the generator circuit breaker is open.

Power required for station auxiliaries (house loads) during normal operation is split between two unit auxiliary transformers. Each unit auxiliary transformer is a three-winding transformer that supplies power to the station auxiliaries on 13.8 KV and 4.16 KV buses.

Two reserve auxiliary transformers serve the station. Offsite power from the 345 KV switchyard is supplied to the 13.8 KV and 4.16 KV buses via the reserve auxiliary transformers during plant start-up, outage, and design bases accident conditions. Each reserve auxiliary transformer is a three-winding transformer that supplies power to the station auxiliaries on 13.8 KV and 4.16 KV buses. The two reserve auxiliary transformers provide a second immediate access circuit from the preferred power supply (offsite source) to the onsite distribution system, providing power for the loads including the engineered safety features loads.

8.4.16.2.2 EVALUATION

Evaluation of the main generator was based on the assumption that the maximum unit real power output is 1295 MWe without modifications to the generator. This output bounds the expected generator output for the proposed licensed core power of 3587 MWt. The remaining power block equipment, unless otherwise noted, was evaluated assuming a maximum unit output of 1314 MWe, which corresponds to an analyzed SPU core power level of 3659 MWt (NSSS power of 3678 MWt), to demonstrate equipment margins.

Main Generator

Evaluation of the main generator was based upon a comparison between the generator capability curve and the anticipated operating requirements when the machine operates at SPU conditions. Unit operation at lagging power factor was considered. The main generator real power output of 1295 MWe bounds the expected generator output for the proposed licensed core power of 3587 MWt, which is calculated based on heat balance model calculations.

The generator capability curve shows that the machine is capable of continuous operation at an output of 1242 MWe (0.92 lagging power factor) up to and including 1350 MWe (unity power factor) at 75 psig hydrogen pressure. The maximum required generator power output is 1295 MWe. Therefore, the real power output capability of the main generator is greater than the real power output required at SPU.

The reactive power capability (MVAR) of the main generator from the generator capability curve is approximately 381 MVAR lagging, at 75 psig hydrogen pressure when the unit operates at 1295 MWe. The generator operation at the specified

values corresponds to a generator lagging power factor of 0.960 at SPU conditions and 75 psig hydrogen pressure. The reactive capability of the main generator satisfies the Seabrook Station reactive power commitments to ISO-NE of 365 MVAR lagging and 0 MVAR leading.

Generator Step-up Transformers

Evaluation of the generator step-up transformers was based upon a comparison between the transformer design ratings and the anticipated maximum transformer loading requirements when the unit operates at SPU conditions.

A load flow/voltage profile system analysis was used to calculate the maximum load on the generator step-up transformers as 1272 MVA with station auxiliaries supplied from the unit auxiliary transformers consistent with the normal plant configuration when the unit is operating at full power. A load flow/voltage profile system analysis was used to calculate the maximum load on the generator step-up transformers at 1332 MVA with station auxiliaries supplied from the reserve auxiliary transformers consistent with the alternate plant configuration when the unit is at full power. The transformers maximum design rating is 1380 MVA at 65°C rise. The evaluation confirms that the existing generator step-up transformer design ratings are adequate to support unit operation at SPU conditions.

Unit Auxiliary Transformers

Evaluation of the unit auxiliary transformers was based upon a comparison between the transformer nameplate design ratings and the anticipated maximum transformer loading requirements when the unit operates at SPU conditions.

To determine the impact of SPU conditions on the unit auxiliary transformers, a baseline for transformer loading was developed that represents the existing loading. Load changes due to SPU conditions were added to the baseline using a computer model. A load flow/voltage profile system analysis was generated to calculate the maximum load on the unit auxiliary transformers at SPU conditions.

The calculated worst-case total transformer input and output transformer loading occurs on transformer ED-X-2A as shown in LAR Tables 8.4.16-6 and 8.4.16-7. The total transformer output load and input load is less than the maximum design rating at 65 ^{0}C rise. The evaluation confirms that the existing unit auxiliary transformer design ratings are adequate to support unit operation at SPU conditions.

Reserve Auxiliary Transformers

Evaluation of the reserve auxiliary transformers was based upon a comparison between the transformer nameplate design ratings and the anticipated maximum transformer loading requirements when the unit operates at SPU conditions.

To determine the impact of SPU conditions on the reserve auxiliary transformers, a baseline for transformer loading was developed that represents the existing loading. Load changes due to SPU conditions were added to the baseline using a computer

model. A load flow/voltage profile system analysis was generated to calculate the maximum load on the reserve auxiliary transformers at SPU conditions.

The calculated worst-case total transformer input and output loading occurs on transformer ED-X-3A as shown in LAR Tables 8.4.16-8 and 8.4.16-9. The total transformer output load and input load is less than the maximum design rating at 65 ^{0}C rise. The evaluation confirms that the existing reserve auxiliary transformer design ratings are adequate to support unit operation at SPU conditions.

Isolated Phase Bus Duct

Evaluation of the isolated phase bus main and tap buses was based upon a comparison between the maximum anticipated full-load current at SPU and the design ratings of the main and tap bus conductors. The generator operates at maximum gross output at lagging power factor and at 95 % of rated voltage. This evaluation is based on station auxiliaries being fed from the unit auxiliary transformers, since this results in the worst-case isolated phase bus loading.

The evaluation results shown in LAR Tables 8.4.16.7 through 8.4.16-10 demonstrate that the continuous current ratings of the isolated phase bus main and tap buses (also shown on the table) exceed the anticipated worst-case bus loading at SPU conditions. Since the isolated phase bus main and tap bus short circuit design ratings were adequate prior to SPU, and SPU did not adversely affect available fault current levels, the isolated phase bus main and tap bus short circuit design ratings are adequate for SPU conditions.

Generator Circuit Breaker

Evaluation of the generator circuit breaker was based upon a comparison between the maximum anticipated full-load current at SPU conditions and the design ratings of the circuit breaker with the generator operating at maximum gross output at lagging power factor and 95 % of rated voltage. The evaluation to determine circuit breaker loading is the same as for the main isolated phase bus above (LAR Table 8.4.16-10). The results demonstrate that the circuit breaker rating of 35 kA exceeds the anticipated worse-case loading at SPU conditions.

Protection for the Main Generator, Generator Step-Up Transformers, Unit Auxiliary Transformers and Reserve Auxiliary Transformers

Evaluation of the main generator protection confirms that the applied protective relaying schemes are dependent upon machine ratings and specific generator design parameters, and the design of the connected system. They are not affected by machine operation at SPU conditions. Physical change to the generator or its design parameters is not required to support an analyzed electrical output of 1295 MWe. Therefore, the generator protective relaying schemes and setpoints are adequate as installed.

Since the existing generator step-up, unit auxiliary and reserve auxiliary transformers will continue in service and operate within their maximum design ratings, the existing

electrical protection schemes and setpoints are unaffected, and acceptable to support unit operation at SPU conditions.

8.4.16.2.3 CONCLUSION

The anticipated operating requirements associated with SPU conditions are bounded by the design ratings of the main generator, isolated phase bus, generator circuit breaker, generator step-up transformers, unit auxiliary transformers and reserve auxiliary transformers. There is no change to the equipment functional design and the equipment continues to meet the requirements of General Design Criteria 17 following implementation of the proposed SPU. The existing physical and electrical separation is not affected, and the power block equipment has the capacity and capability to supply power to the safety-related loads and other required equipment at SPU conditions.

8.4.16.3 DC SYSTEM

8.4.16.3.1 DESCRIPTION

The DC System is discussed in the Seabrook Station UFSAR Section 8.3.2. The evaluation of the DC System and its components demonstrates that the current design of the safety-related and non-safety-related portions of the system is acceptable to support operation at SPU conditions.

The station 125 VDC system is comprised of batteries, battery chargers and distribution equipment that supply 125 VDC power to station loads. The DC System is divided into two separate portions. The nuclear safety-related (Class 1E) portion of the DC System consists of four 125 VDC batteries, battery chargers and DC buses. It provides the source of power for direct current load groups, vital control and instrumentation, power and control of Class 1E and selected non-Class 1E electrical equipment. The non-safety-related (non-Class 1E) portion of the station DC system consists of two 125 VDC batteries, battery chargers and DC buses. The non-safety-related portion supplies power to non-vital load groups, instrumentation, and power and control to non-Class 1E electrical equipment.

8.4.16.3.2 EVALUATION

The DC System and components were evaluated to ensure required functions are performed after the implementation of SPU and, consequently, to ensure the capability to facilitate the functioning of systems, structures and components important to safety.

The safety-related and non-safety-related portions of the 125 VDC system were reviewed to determine potential changes due to SPU with consideration to normal, maintenance and emergency modes of operation. The NSSS was reviewed and it was determined that no new DC loads were added and no DC load increases were identified for the existing loads. The BOP systems, including the turbine generator auxiliaries, were reviewed and it was determined that there were no new DC loads added and no DC load increases were identified for the existing loads. In addition,

the Station Blackout and Appendix R program evaluations did not result in any 125 VDC system load changes.

The DC System is not affected by SPU and continues to have the capacity and capability to supply power to the safety loads as required in General Design Criteria 17.

8.4.16.3.3 CONCLUSION

SPU will not affect the DC System. Therefore, there is no change in the system's functional design and the system continues to meet its licensing basis functions following implementation of the proposed SPU. The DC System will continue to meet the requirements of General Design Criteria 17 at SPU conditions. Adequate physical and electrical separation exists, and the DC system has the capacity and capability to supply power to the safety loads and other required equipment at SPU conditions.

8.4.16.4 EMERGENCY DIESEL GENERATOR FUEL OIL AND LUBE OIL SYSTEMS

The Diesel Generator Fuel Oil Storage and Transfer System and Lubrication System are discussed in the Seabrook Station UFSAR Sections 9.5.4 and 9.5.7, respectively. Each diesel generator has a completely independent fuel oil storage and transfer system sufficient to maintain operation of the diesel generator for 7 days, to meet the maximum Engineered Safety Feature load requirements following a loss of offsite power and design basis accident. The diesel generator lubrication system provides essential lubrication to the components of the diesel engines, and removes heat due to friction from the engine. The system is capable of maintaining continuous operation of the diesel engine without degradation of engine function. The evaluation of the Emergency Diesel Generator Fuel Oil and Lubrication Systems demonstrate that the Emergency Diesel Generator and its auxiliary systems requirements remain bounded for operation at SPU conditions. The Emergency Diesel Generators and Auxiliaries are reviewed in LAR Subsection 8.4.16.5.

The quantity of fuel oil, fuel consumption rate, and lube oil requirements were evaluated to ensure that required functions are performed after implementation of SPU, consequently, to ensure the functionality of the Emergency Diesel Generator System. Specifically:

- Emergency Diesel Generator loading and cooldown mode run times will not change at SPU conditions. Therefore, the quantity of fuel oil required is bounded by Technical Specification limits, and fuel consumption rates are not affected for emergency diesel generator operational requirements at SPU conditions.
- Emergency Diesel Generator loading, cooldown mode run times and emergency diesel generator lube oil inventory will not change at SPU conditions. The lube oil inventory is bounded by Technical Specification limits. Therefore, the emergency diesel generator auxiliary systems are not affected by the SPU conditions and remain within emergency diesel generator design limitations.

Therefore, the Fuel Oil Storage and Transfer System will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of General Design Criteria 4, 5 and 17.

8.4.16.5 EMERGENCY DIESEL GENERATORS AND AUXILIARIES

8.4.16.5.1 DESCRIPTION

The Emergency Diesel Generator System is discussed in the Seabrook Station UFSAR Section 8.3.1. The evaluation of the Emergency Diesel Generator System and auxiliaries demonstrates that the current Emergency Diesel Generator Loading Analysis remains bounding for operation at SPU conditions.

The Emergency Diesel Generator System provides a safety-related source of AC power to sequentially energize and restart those loads necessary to shutdown the reactor safely, and maintains it in a safe shutdown condition. The system is capable of performing this function during a loss of off-site power, with or without a coincident loss-of-coolant accident. There are two emergency diesel generator sets of identical design, each dedicated to one of the safety-related, redundant engineered safety features electrical trains.

8.4.16.5.2 EVALUATION

The Emergency Diesel Generator System and auxiliaries were evaluated to ensure that required functions are performed after the implementation of SPU and, consequently, to ensure the functionality of the Emergency Diesel Generator System. Specifically:

- Emergency diesel generator loading is composed of NSSS loads, turbine generator auxiliary loads, and BOP loads as listed in the Seabrook Station UFSAR Table 8.3-1 and Emergency Diesel Generator Loading Analysis.

  The NSSS loads were reviewed by Westinghouse to determine that the loads and cooldown mode run time requirements are not impacted and do not change at SPU conditions.

  The turbine generator auxiliary loads were reviewed by General Electric to determine that the loads are not impacted and do not change at SPU conditions.

  BOP loads were reviewed. Applicable Engineering Report System analyses have determined that the loads and cooldown mode run time requirements are not impacted and do not change at SPU conditions.

  Therefore, the emergency diesel generator loading does not change at SPU conditions, and is bounded by the existing Emergency Diesel Generator Loading Analysis.

- The emergency diesel generator loading will not change at SPU conditions. Therefore:

The emergency diesel generator output voltage and frequency levels and motor starting terminal voltage levels under emergency diesel generator operation at SPU conditions are bounded by the existing Load Flow/Voltage Profile Analysis.

The existing emergency diesel generator protective relay settings at SPU conditions remain as determined in the Diesel Generator Relay Setting Analysis.

There is no change to the emergency diesel generator ratings. Therefore, the Emergency Diesel Generator Service Water System cooling requirements to the emergency diesel generator water jacket heat exchangers at SPU are bound by design.

The emergency diesel generators will be operating within design ratings at SPU conditions, with no impact to their environment.

The Emergency Diesel Generation System, part of the AC Onsite Power System, was evaluated for impact from operation at SPU conditions to ensure compliance with the General Design Criteria 17 requirements for the capability of the AC Onsite Power System to perform its intended functions during plant operating and accident conditions. The Emergency Diesel Generation System will continue to meet the requirements of General Design Criteria 17.

8.4.16.5.3 CONCLUSION

Review of the NSSS loads, turbine generator auxiliary loads, and BOP loads for operation at the SPU conditions indicates that there is no increase in the Emergency Diesel Generator loading. It was determined that there are no load additions or modifications to the present emergency diesel generator loading due to the SPU. Therefore, there is no impact to the existing Emergency Diesel Generator Loading Analysis, which is bounding at SPU conditions.

The emergency diesel generators are capable of performing their design and licensing functions at SPU conditions. No additional analysis is required to demonstrate their acceptability. No emergency diesel generator modifications are required to support SPU operation.

Since the emergency diesel generator loading is bounded by existing analysis, the existing protective relay settings are not impacted by SPU conditions. No Protection System modifications are required to support SPU operation.

As there are no changes to the emergency diesel generator loading conditions, the AC onsite power system will continue to meet the requirements of General Design Criteria 17 following implementation of SPU.

8.4.16.6 SWITCHYARD

8.4.16.6.1 DESCRIPTION

The switchyard is described in Seabrook Station UFSAR Section 8.2.1.3. The evaluation of the switchyard equipment and components, which is based on the maximum output rating of the generator step-up transformers, demonstrates that the

current design of the system is acceptable to support an analyzed electrical output of 1314 MWe, which corresponds to an analyzed SPU core power level of 3659 MWt (NSSS power of 3678 MWt).

The switchyard equipment and associated components are classified as non-safety-related. The primary function of the 345 KV switchyard and distribution system is to connect the station electrical system to the New England transmission grid. The interconnection allows for:

- The normal flow of power out of the station to the grid when the main generator is operating, and
- The flow of power from the grid to the station auxiliaries when the main generator is shut down.

The 345 KV switchyard and distribution system, including the connections to the high voltage bushings of the generator step-up transformers and reserve auxiliary transformers, use sulfur hexafluoride (SF6) gas insulated buses. The switchyard itself is a double bus switchyard (345 KV buses 1 and 2) that utilizes a breaker-and-a-half arrangement to connect the station output to the transmission grid.

8.4.16.6.2 EVALUATION

The 345 KV switchyard and distribution system were evaluated to ensure required functions are performed after the implementation of SPU and, consequently, to ensure the functionality of the switchyard and its associated components.

The evaluation determined that no changes are required to the 345 KV switchyard equipment or associated components. The 345 KV switchyard equipment ratings, including the SF6 insulated buses to the high voltage bushings of the generator step-up transformers and reserve auxiliary transformers were determined to bound the SPU operating condition requirements.

The switchyard configuration has not changed due to SPU, and with the generator circuit breaker open, it continues to provide a reliable offsite power supply path to the station onsite distribution system through the generator step-up transformers and unit auxiliary transformers. The reserve auxiliary transformers provide a second access circuit to the onsite distribution system. The separate circuits satisfy the independence and redundancy requirements of General Design Criteria 17.

8.4.16.6.3 CONCLUSION

SPU is predicted not to impact the 345 KV switchyard and distribution system. Therefore, there is no change to its functional design and the system continues to meet the requirements of General Design Criteria 17 following implementation of the proposed SPU. The existing physical and electrical separation is not affected, and the offsite power system has the capacity and capability to supply power to the safety-related loads and other required equipment.

8.4.16.7 GRID STABILITY

Power flow and stability studies are discussed in Seabrook Station UFSAR Sections 8.2.2.3 and 8.2.3. An "Uprate System Impact Study" has been completed to evaluate the system impacts in accordance with "New England Power Pool (NEPOOL) Reliability Standards" and "NEPOOL Minimum Interconnection Standards".

The approach used in the study was to utilize NEPOOL study models, updated for the year 2007. It compares performance of the system before and after the proposed SPU to demonstrate the impact under a prescribed set of initial conditions and contingencies established in cooperation with the NEPOOL transmission owners and ISO-NE. The evaluation considered an analyzed electrical output of 1295 MWe which is the maximum capability of the existing generator without modifications and is 86 MWe above the present gross output of 1209 MWe. This electrical output bounds the predicted heat balance conditions / electrical generation at the SPU licensed core power level of 3587 MWt.

The study demonstrates system performance with and without SPU for pre-contingency and post-contingency voltages and line loading, and for dynamic response to system disturbances. The study indicates that the SPU of Seabrook Station will not have a significant adverse effect on the reliability or operating characteristics of the station or on the offsite electrical system. The SPU system impact study has demonstrated that the steady state and dynamic performance of the Seabrook Station at SPU conditions is acceptable without any required hardware modifications. Seabrook Station's design will continue to meet the intent of General Design Criterion 17 at SPU conditions.

8.4.17 BOP INSTRUMENTATION AND CONTROLS

The SPU evaluation of the BOP Instrumentation and Controls demonstrated that except as noted below, the design of the BOP instruments, ranges and setpoints will remain bounded for SPU operation. Nuclear Steam Supply Systems instrumentation is reviewed in LAR Section 4.3. The instrumentation and control systems are discussed in Seabrook Station UFSAR Chapter 7.

As a result of the SPU evaluation the following changes will be required during SPU implementation:

- **Feedwater Flow Indication Control Room Banding**

  Main feedwater flow to each steam generator increases to approximately 4.120 million pounds per hour at SPU conditions. Indicators in the control room monitor feedwater flow and are banded (green color) for a range between 3.5 to 4.0 million pounds per hour. Because SPU flow will exceed the indicator-banded range, these indicators will require re-banding. A banding range between 3.75 and 4.25 million pounds per hour will be utilized. This change will also be implemented into the Plant Simulator.

- **Main Steam Flow Indication Control Room Banding**

  Main steam flow from each steam generator increases to approximately 4.097 million pounds per hour at SPU conditions. The above indicators monitor main steam flow and are banded (green color) for a range between 3.5 to 4.0 million pounds per hour. Because SPU flow will exceed the indictor-banded range, these indicators will require rebanding. A banding range between 3.75 and 4.25 million pounds per hour is recommended. This change will also be implemented into the Plant Simulator

- **Main Feedwater Pump Turbine Speed Control Set Point**

  With the SPU, the operating differential pressure between feedpump discharge header and the main steam header pressure increases from 165 psid to approximately 200 psid (nominal). This differential pressure measurement is used to establish the feedpump turbine speed. The feedpump speed remains unchanged for SPU operating conditions (Refer to LAR Subsection 8.4.3). Therefore, the differential pressure input into the feedpump turbine speed control system will be changed from 165 psid to 200 psid (nominal). This change will also be implemented into the Plant Simulator.

- **Condensate Pump Recirculation Valve Controller Setpoint.**

  The set point for the condensate pump(s) short term minimum flow recirculation pressure controllers, will be increased to 540 psig (approximately 10 psi from the current setting). This recommended set point must be confirmed once the modifications to the condensate pumps are complete. (Refer to LAR Subsection 8.4.3) and the final pump characteristic curve is established.

The evaluation of the RG 1.97 variables associated with the BOP fluid systems have demonstrated that the indicated range for the RG 1.97 instruments will still meet the 10% margin above the design flow required by the Regulatory Guide. For example, main feedwater flow increased however SPU flow remains within an indicated range of 110% design flow.

A modification to the first stage high pressure turbine pressure setpoint will be performed based on the modified high pressure turbine steam path.

TABLE 8.4.12-1
NORMAL OPERATION (ATLANTIC OCEAN)

SOURCE	DESIGN ($X10^6$ BTU/hr)	CURRENT ($X10^6$ BTU/hr)	SPU ($X10^6$ BTU/hr)
Primary component cooling water heat exchanger	168.6	74.7	75.6
Secondary component cooling water heat exchanger	56.0	56.0	56.0
Total	224.6	130.7	131.6

TABLE 8.4.12-2
LOCA (COOLING TOWER)

SOURCE	DESIGN ($X10^6$ BTU/hr)	CURRENT ($X10^6$ BTU/hr)	SPU ($X10^6$ BTU/hr)
Primary component cooling water heat exchanger	146.0	146.0	166.4
Diesel generator water jacket heat exchanger	31.1	31.1	31.1
Total	177.1	177.1	197.5
Cooling tower design	217.5	–	–

TABLE 8.4.13-1
PRIMARY COMPONENT COOLING WATER

Equipment Description Loop A	Normal Operation (w/Leakage) Heat Loads ($X10^6$ BTU/hr)		Normal Cooldown 4 hr/24 hr Heat Loads ($X10^6$ BTU/hr)		Extended Cooldown Heat Loads ($X10^6$ BTU/hr)		Post-LOCA (Ocean or Cooling Tower as Ultimate Heat Sink) Heat Loads ($X10^6$ BTU/hr)	
	Current	SPU	Current	SPU	Current	SPU	Current	SPU
Containment Spray Pump	—	—	—	—	—	—	0.18	0.18
Safety Injection Pump	—	—	—	—	—	—	0.075	0.075
Residual Heat Removal Pump	—	—	0.075	0.075	0.075	0.075	0.075	0.075
Containment Spray Heat Exchanger	—	—	—	—	—	—	63.9	74.8
Residual Heat Removal Heat Exchanger	—	—	119/ 35.1	119.5/ 39.1	148.5	180.6	75.7	85.3
Sample Heat Exchangers	1.6	1.6	1.6	1.6	1.6	1.6	—	—
Centrifugal Charging Pump	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Containment Enclosure Fan Cooler	0.73	0.73	0.73	0.73	1.18	1.18	1.18	1.18
Containment Structural Cooling Units	3.6	3.7	3.6	3.7	3.6	3.7	—	—
Reactor Coolant Pumps	4.8	4.8	2.4	2.4	2.4	2.4	—	—
Spent Fuel Pool Heat Exchanger	7.79	8.11	7.79	8.11	15.58	16.22	15.58 (1)	16.22 (1)
Letdown Heat Exchanger	6.51	6.51	1.2	1.2	1.2	1.2	—	—
Seal Water Heat Exchanger	1.6	1.6	0.75	0.75	0.75	0.75	0.75	0.75
Letdown Degas Trim Cooler	1.64	1.64	3.0	3.0	—	—	—	—
Letdown Degas Hotwell Condenser	0.05	0.05	0.05	0.05	—	—	—	—
Reactor Coolant Drain Tank	2.43	2.43	2.43	2.43	—	—	—	—
Waste Gas Compressor.	0.27	0.27	0.27	0.27	0.27	0.27	—	—
Instrument Air Compressor	0.14	0.14	0.14	0.14	0.14	0.14	—	—
Liquid Waste Evaporator (2)	—	—	—	—	—	—	—	—
Boron Recovery Evaporator(2)	—	—	—	—	—	—	—	—
Steam Generator Blowdown Evaporator(2)	—	—	—	—	—	—	—	—
Mechanical Seal Heat Exchanger	0.02	0.02	0.02	0.02	—	—	—	—
Thermal Barrier Heat Exchanger	0.4	0.4	0.4	0.4	5.6	5.6	2.4	2.4
Steam Generator Building Heat Exchanger 142	11.2	11.2	—	—	—	—	—	—
Pumping & Friction Heat	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Total	44.4	44.9	145.1 / 61.2	146.0 / 65.6	182.6	215.4	146.0	166.4
Heat Exchanger Rating	326		326		326		326	

Notes:

(1) Heat load is not transferred initially but is imposed following recirculation peak load and is not included in totals.

(2) This equipment is not in operation and primary component cooling water valves have been closed.

TABLE 8.4.13-2
PRIMARY COMPONENT COOLING WATER

Equipment Description Loop B	Normal Operation (w/Leakage) Heat Loads ($X10^6$ BTU/hr)		Normal Cooldown 4 hr/24 hr Heat Loads ($X10^6$ BTU/hr)		Extended Cooldown Heat Loads ($X10^6$ BTU/hr)		Post-LOCA (Ocean or Cooling Tower as Ultimate Heat Sink) Heat Loads ($X10^6$ BTU/hr)	
	Current	SPU	Current	SPU	Current	SPU	Current	SPU
Containment Spray Pump	—	—	—	—	—	—	0.18	0.18
Safety Injection Pump	—	—	—	—	—	—	0.075	0.075
Residual Heat Removal Pump	—	—	0.075	0.075	0.075	0.075	0.075	0.075
Containment Spray Heat Exchanger	—	—	—	—	—	—	63.9	74.8
Residual Heat Removal Heat Exchanger	—	—	119/ 35.1	119.5/ 39.1	148.5	181.6	75.7	85.3
Charging Pumps	0.48	0.48	0.08	0.08	0.08	0.08	0.08	0.08
Containment Enclosure Fan Cooler	0.73	0.73	0.73	0.73	1.18	1.18	1.18	1.18
Containment Structure Cooling Units	3.6	3.7	3.6	3.7	3.6	3.7	—	—
Reactor Coolant Pumps	4.8	4.8	2.4	2.4	2.4	2.4	—	—
Spent Fuel Pool Heat Exchanger	7.79	8.11	7.79	8.11	15.58	16.22	15.58 (1)	16.22 (1)
Primary Drain Tank Degasifier	1.64	1.64	3.0	3.0	—	—	—	—
Primary Drain Tank Degasifier Condenser	0.048	0.048	0.048	0.048	—	—	—	—
Purge Gas Condenser & Compressor	0.14	0.14	0.14	0.14	0.14	0.14	—	—
Instrument Air Compressor	0.14	0.14	0.14	0.14	0.14	0.14	—	—
Swing Boron Recovery Evaporator(2)	—	—	—	—	—	—	—	—
Steam Generator Evaporator A & C(2)	—	—	—	—	—	—	—	—
Steam Generator Building Fl. Tank Cooler	1.2/3.12	1.2/3.12	—	—	—	—	—	—
Steam Generator Building. Fl. Tank Condenser(2)	—	—	—	—	—	—	—	—
Boron Regeneration Chiller (2)	—	—	—	—	—	—	—	—
Pressurizer Relief Tank Heat Exchanger	2.43	2.43	—	—	—	—	—	—
Seal Water Heat Exchanger	—	—	—	—	—	—	—	—
Mechanical Seal Heat Exchanger	1.6	1.6	0.75	0.75	0.75	0.75	0.75	0.75
Thermal Barrier Heat Exchanger	0.02	0.02	0.02	0.02	—	—	—	—
Steam Generator Building Radiation Monitor	2.0	2.0	2.0	2.0	5.6	5.6	2.4	2.4
Steam Generator Building. Heat Exchanger 142 (2)	0.2	0.2	0.2	0.2	0.2	0.2	—	—
Solid Waste Cooling Loads (2)	—	—	—	—	—	—	—	—
Pumping & Friction Heat								
Total	28.4 / 30.3	28.8 / 30.7	141.5 / 57.6	142.5 / 62.1	179.8	213.7	146.0	166.4
Heat Exchanger Rating	326		326		326		326	

Notes:

(1) Heat load is not transferred initially but is imposed following recirculation peak load and is not included in totals.

(2) This equipment is not in operation and primary component cooling water valves have been closed.

TABLE 8.4.15-1
ESTIMATED IMPACT ON ANNUAL EFFLUENT DOSES DUE TO SPU

Type of Dose	Appendix I Design Objectives	Calculated Doses From Seabrook Final Environmental Statement Appendix I Analysis for Maximum Hypothetical Individual	Maximum Estimated Dose Impact Following the SPU for Maximum Individual Based on current 5-yr Operations(1)
Liquid Effluents			
Dose to total body from all pathways	3 mrem/yr per unit	0.002 mrem/yr	0.00119 mrem/yr
Dose to any organ from all pathways	10 mrem/yr per unit	0.07 mrem/yr	0.00492 mrem/yr
Gaseous Effluents			
Gamma Dose in Air	10 mrad/yr per unit	0.3 mrad/yr	0.000925 mrad/yr
Beta Dose in Air	20 mrad/yr per unit	0.43 mrad/yr	0.00119 mrad/yr
Dose to total body of an individual	5 mrem/yr per unit	0.19 mrem/yr	Not reported in Seabrook effluent reports assumed small based on low gamma and beta air doses
Dose to skin of an individual	15 mrem/yr per unit	0.4 mrem/yr	Not reported in Seabrook effluent reports assumed small based on low gamma and beta air doses
Radioiodines and Particulates Released to the Atmosphere			
Dose to any organ from all pathways	15 mrem/yr per unit	1.1 mrem/yr	0.194 mrem/yr

Note:

(1) Core power level analyzed for SPU analysis is 3659 MWt

TABLE 8.4.15-2
VITAL ACCESS DOSES TO PERSONNEL FOLLOWING SPU(1)

Area	Initial Access Time	Occupancy Factor	Depressurized LOCA – Dose	Pressurized LOCA - Dose
Chemistry Lab-Counting Room	Per NUREG 0737 II.B.3	Per NUREG 0737 II.B.3	< 2.81 R	2.14 R
Post Accident Sampling System - Reactor Coolant System - Align Air Sampler - Obtain Air Sample	Per NUREG 0737 II.B.3	Per NUREG 0737 II.B.3	 < 1.04 R < 1.40 R < 1.94 R	1.04 R
Switchgear Room	1 hr	0.5 for a period 1-8 hrs	0.141 R	0.027 R
Radwaste Control Station	1 hr	0.5 for a period 1-8 hrs	0.079 R	0.151 R
RCA Tunnel	1 hr	Transit time only	< 15 mrem/hr	< 15 mrem/hr

Notes:

(1) Per NUREG 0737 II.B.2, maximum allowable dose limit for post-accident operator exposure is 5 Rem whole body.

TABLE 8.4.16-1
SHORT CIRCUIT CURRENT AT SWITCHGEAR BUSES AT SPU CONDITIONS
(MAXIMUM FULL LOAD)

Bus	Bus Rated Voltage, Volts	Short Circuit Current, kA Sym.				
		Interrupting			Momentary	
		Calculated SC Duty (Adjusted) (Note 1)	SC Rating At Max. Voltage (Note 2)	Adjusted SC Rating (Note 2)	Calculated (Note 1)	SC Rating (Note 2)
1	13,800	19.175	19.3	20.267	33.539	40
2	13,800	18.490	19.3	20.162	31.501	40
3	4160	40.146	42.4	45.333	72.466	80
4	4160	40.408	42.4	45.039	71.605	80
E5	4160	39.867	42.4	45.363	71.946	80
E6	4160	39.735	42.4	45.080	70.634	80

Notes:

1. Calculated breaker short circuit current values are taken from the short circuit current system analysis computer runs. The short circuit current interrupting duty is adjusted to the calculated equipment pre-fault voltage.
2. Breaker interrupting and momentary short circuit current ratings for 13,800 V and 4160 V switchgears are taken from switchgear specifications and breaker certifications. The short circuit current interrupting ratings are adjusted to the calculated equipment pre-fault voltage.

TABLE 8.4.16-2
MINIMUM VOLTAGE AT SWITCHGEAR BUSES AND AFFECTED MOTORS (MAXIMUM FULL LOAD)

Bus	Bus Voltage Volts				Affected Motor Load	Motor Terminal Voltage Volts			
	Rated	Present Calculated (Note 1)	SPU Calculated (Note 1)	Min. Required (Note 2)		Rated	Present Calculated (Note 1)	SPU Calculated (Note 1)	Min. Required (Note 3)
1	13,800	12,825	12,812	N/A	Reactor Coolant Pumps RC-P-1A	13,200	12,817	12,803	11,880
					RC-P-1B	13,200	12,816	12,802	11,880
2	13,800	12,934	12,921	N/A	Reactor Coolant Pumps RC-P-1C	13,200	12,923	12,909	11,880
					RC-P-1D	13,200	12,924	12,911	11,880
3	4160	4014	4006	N/A	Condensate Pumps CO-P-30A	4000	4008	4000	3600
					CO-P-30C	4000	4008	4000	3600
					Heater Drain Pump HD-P-31A	4000	4010	4003	3600
4	4160	4044	4040	N/A	Condensate Pump CO-P-30B	4000	4038	4034	3600
					Heater Drain Pump HD-P-31B	4000	4040	4037	3600
E5	4160	4011	4004	4004	None				
E6	4160	4039	4036	4004	None				

Notes:

1. Calculated Present and SPU minimum voltage values at switchgear buses and affected motor terminals are taken from the load flow/voltage profile system analysis computer runs.
2. Minimum required voltage at each safety-related Bus E5 and E6 is the maximum reset value of 4004 V for the Degraded Voltage Relay.
3. Required minimum voltage at motor terminals is 90% of rated voltage.

TABLE 8.4.16-3
STARTING TERMINAL VOLTAGE OF AFFECTED MOTORS AT SPU CONDITIONS
(MAXIMUM FULL LOAD)

Bus	Affected Motor Load	Motor Terminal Voltage, Volts		
		Rated	Calculated (Note 1)	Min. Required (Note 2)
1	Reactor Coolant Pump RC-P-1B	13,200	11,281	10,560
2	Reactor Coolant Pump RC-P-1C	13,200	11,393	10,560
3	Condensate Pump CO-P-30A	4000	3561	3200
	Heater Drain Pump HD-P-31A	4000	N/A	N/A
4	Condensate Pump CO-P-30B	4000	3598	3200
	Heater Drain Pump HD-P-31B	4000	N/A	N/A

Notes:

1. Calculated motor starting voltage values are taken from the load flow/voltage profile system analysis computer runs.
2. Required minimum voltage is 80% of rated voltage for a starting motor, and 75% of rated voltage for other loads running on the same bus.

TABLE 8.4.16-4
INCREMENTAL LOAD OF AFFECTED MOTORS AND IMPACT ON SWITCHGEAR BUSES
(MAXIMUM FULL LOAD)

Bus	Affected Motor Load	Rated HP	Present Load BHP	SPU Load BHP	Present Load Flow (Note 1)			SPU Load Flow (Note 2)			Incremental Load (Note 3)		
					MW	MVAR	MVA	MW	MVAR	MVA	MW	MVAR	MVA
1	RC-P-1A	7000	6835	7124	5.512	2.447	6.031	5.745	2.555	6.287	0.233	0.108	0.256
	RC-P-1B	7000	6835	7124	5.512	2.447	6.031	5.745	2.555	6.287	0.233	0.108	0.256
	Total Bus 1 SPU Incremental Load										0.466	0.216	0.514
2	RC-P-1C	7000	6835	7124	5.512	2.447	6.031	5.745	2.555	6.287	0.233	0.108	0.256
	RC-P-1D	7000	6835	7124	5.512	2.447	6.031	5.745	2.555	6.287	0.233	0.108	0.256
	Total Bus 2 SPU Incremental Load										0.466	0.216	0.514
3	CO-P-30A	3500	3200	3500	2.510	1.084	2.734	2.746	1.186	2.991	0.236	0.102	0.262
	CO-P-30C	3500	3200	3500	2.510	1.084	2.734	2.746	1.186	2.991	0.236	0.102	0.262
	HD-P-31A	1250	1142	1103	0.904	0.393	0.986	0.874	0.380	0.953	-0.030	-0.013	-0.033
	Total Bus 3 SPU Incremental Load										0.442	0.191	0.482
4	CO-P-30B	3500	3200	3500	2.510	1.084	2.734	2.746	1.186	2.991	0.236	0.102	0.262
	HD-P-31B	1250	1142	1103	0.904	0.393	0.986	0.874	0.380	0.953	-0.030	-0.013	-0.033
	Total Bus 4 SPU Incremental Load										0.206	0.089	0.224

Notes:

1. Present Load Flow (MW, MVAR and MVA) represents the existing calculated values.
2. SPU Load Flow (MW, MVAR and MVA) is taken from the load flow/ voltage profile system analysis computer runs.
3. Incremental Load is calculated as follows:
   - Incremental MVAR = (SPU Load, MVAR) - (Present Load, MVAR)
   - Incremental MW = (SPU Load, MW) - (Present Load, MW)
   - Incremental MVA = [(Incremental MW)2 + (Incremental MVAR)2] 1/2

TABLE 8.4.16-5
MOTOR LOAD CURRENT AND FEEDER CABLE AMPACITY AT SPU CONDITIONS

Bus	Affected Motor Load	SPU BHP Load	SPU Load Flow, MVA (Note 1)	SPU Motor Load Current, Amps (Note 2)	Feeder Cable Derated Ampacity Amps (Note 3)	Penetration Cable Derated Ampacity, Amps (Note 4)
1	RC-P-1A	7124 (Hot) 9083 (Cold)	6.287 (Hot)	306 (Hot) 390 (Cold)	436	600
	RC-P-1B	7124 (Hot) 9083 (Cold)	6.287 (Hot)	306 (Hot) 390 (Cold)	436	600
2	RC-P-1C	7124 (Hot) 9083 (Cold)	6.287 (Hot)	306 (Hot) 390 (Cold)	436	600
	RC-P-1D	7124 (Hot) 9083 (Cold)	6.287 (Hot)	306 (Hot) 390 (Cold)	436	600
3	CO-P-30A	3500	2.991	480	618	N/A
	CO-P-30C	3500	2.991	480	618	N/A
	HD-P-31A	1103	0.953	153	232	N/A
4	CO-P-30B	3500	2.991	480	618	N/A
	HD-P-31B	1103	0.953	153	232	N/A

Notes:

1. SPU Load Flow (MVA) is taken from the load flow/ voltage profile system analysis computer runs.
2. The SPU Motor Load Current (Amps) for affected pump motor drives is calculated at 90% motor rated voltage.
3. Feeder cable derated ampacity (Amps) are existing design ratings.
4. Penetration cable derated ampacity (Amps) are existing design ratings.

TABLE 8.4.16-6
UNIT AUXILIARY TRANSFORMER MAXIMUM OUTPUT LOADING
ED-X-2A

Secondary Winding	Output Loading						Maximum Nameplate Rating		Notes
	X-Winding			Y-Winding			X-Winding	Y-Winding	
	MW	MVAR	MVA	MW	MVAR	MVA	MVA	MVA	
Existing	20.73	11.73	23.81	12.35	6.43	13.92	26.88@65°C (FA)	17.92@65°C (FA)	1
SPU+ Existing	21.19	11.95	24.33	12.80	6.64	14.42			2
Increment	0.46	0.22	0.52	0.45	0.21	0.50			3
Total Output Load	21.19	11.95	24.33	12.80	6.64	14.42	26.88@65°C	17.92@65°C	

Notes:

1. Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated loading on the transformers prior to SPU.
2. SPU + Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated input loading on the primary winding of the transformers after SPU.
3. Increment loading is the difference between Existing and SPU + Existing loading. These values represent the additional input loading on the primary winding of the transformers as a result of SPU.

TABLE 8.4.16-7
UNIT AUXILIARY TRANSFORMER MAXIMUM INPUT LOADING
ED-X-2A

Primary Winding	Input Loading			Maximum Nameplate Rating	Notes
	H- Winding				
	MW	MVAR	MVA	MVA	
Existing	33.25	20.59	39.11	40.32@65°C (FA)	1
SPU+Existing	34.18	21.17	40.20		2
Increment	0.93	0.58	1.09		3
Total Input Load	34.18	21.17	40.20	40.32@65°C	

Notes:

1. Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated loading on the transformers prior to SPU.
2. SPU + Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated input loading on the primary winding of the transformers after SPU.
3. Increment loading is the difference between Existing and SPU + Existing loading. These values represent the additional input loading on the primary winding of the transformers as a result of SPU.

TABLE 8.4.16-8
RESERVE AUXILIARY TRANSFORMER MAXIMUM OUTPUT LOADING
ED-X-3A

Secondary Winding	Output Loading						Maximum Nameplate Rating		Notes
	X-Winding			Y-Winding			X-Winding	Y-Winding	
	MW	MVAR	MVA	MW	MVAR	MVA	MVA	MVA	
Existing	20.73	11.74	23.82	12.35	6.43	13.92	26.88@65°C (FA)	17.92@65°C (FA)	1
Existing+SPU	21.20	11.97	24.34	12.80	6.64	14.42			2
Increment	0.47	0.23	0.52	0.45	0.21	0.50			3
Total Output Load	21.20	11.97	24.34	12.80	6.64	14.42	26.88@65°C	17.92@65°C	

Notes:

1. Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated loading on the transformers prior to SPU.
2. SPU + Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated input loading on the primary winding of the transformers after SPU.
3. Increment loading is the difference between Existing and SPU + Existing loading. These values represent the additional input loading on the primary winding of the transformers as a result of SPU.

TABLE 8.4.16-9
RESERVE AUXILIARY TRANSFORMER MAXIMUM INPUT LOADING
ED-X-3A

Primary Winding	Input Loading			Maximum Nameplate Rating	Notes
	H- Winding				
	MW	MVAR	MVA	MVA	
Existing	33.26	20.74	39.19	40.32@65°C (FA)	1
SPU+Existing	34.18	21.31	40.28		2
Increment	0.92	0.57	1.09		3
Total Input Load	34.18	21.31	40.28	40.32@65°C	

Notes:

1. Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated loading on the transformers prior to SPU.
2. SPU + Existing loading is derived from a load flow/voltage profile system analysis. These values represent the present calculated loading on the transformers after SPU.
3. Increment loading is the difference between Existing and SPU + Existing loading. These values represent the additional loading on the transformers as a result of SPU.

TABLE 8.4.16-10
ISOLATED PHASE BUS DUCT LOADING
(STATION LOADS FROM UNIT AUXILIARY TRANSFORMERS)

Generator Output				Main Bus	Tap Bus to GSU	Extension Tap Bus to UATs	Tap Bus to UAT 2A	Tap Bus to UAT 2B
MVA	MWe	MVAR	Voltage (%)	(Note 1) Load (kA)	(Note 2) Load (kA)	(Note 3) Load (kA)	(Note 3) Load (kA)	(Note 3) Load (kA)
1364	1314	365	95	33.1	18.25	1.78	0.98	0.80

Notes:

1. The design rating of the isolated phase bus duct, main bus is 35 kA forced-cooled.
2. The design rating of the isolated phase bus duct, tap bus to generator step-up transformers is 20 kA self-cooled.
3. The design rating of the isolated phase bus duct, extension tap bus and tap bus to unit auxiliary transformers 2A and 2B is 3 kA self-cooled.

8.5 PIPING AND SUPPORTS

8.5.1 BOP PIPING AND SUPPORTS

8.5.1.1 DESCRIPTION

Piping and structural analyses are discussed in Seabrook Station UFSAR Chapter 3. The evaluations of piping and supports demonstrate that the current design is acceptable to support operation for a proposed PU at an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The BOP piping systems evaluated for SPU conditions included the following systems:

- Main Steam
- Extraction Steam
- Condensate and Feedwater
- Steam Generator Blowdown
- Circulating Water
- Heater Drains (including Moisture Separator and Reheater Drains)
- Service Water (including essential and non- essential)
- Component Cooling Water (Primary and Secondary)
- Radwaste Systems
- Auxiliary Steam
- Boron Recovery
- Chilled Water
- Demineralized Water
- Fire Protection
- Fuel Oil
- Instrument Air
- Reactor Make-up Water
- Sampling System

8.5.1.2 EVALUATION

System operation at SPU conditions generally results in increased pipe stress levels, pipe support loads and equipment nozzle loads due to slightly higher operating temperatures, pressures and flow rates internal to the piping. The piping was evaluated to the current code of record for Seabrook Station.

Piping Description	Piping Analysis Code
Safety Related	ASME Section III, 1977 Edition
Non-Safety	ANSI B31.1, 1973 Edition

The BOP piping systems affected by SPU were evaluated as follows.

Current and SPU operating data (operating temperature, pressure, and flow rate) were obtained from heat balance diagrams and calculations.

Change Factors were determined, as required, to evaluate and compare the changes in operating conditions. The thermal, pressure and flow rate change factors were based on the following ratios:

- The thermal change factor will be determined by the ratio of the power uprate to current operating temperature. That is, thermal change factor is $(T_{uprate}-70°F)/(T_{current}-70°F)$.
- The pressure change factor will be determined by the ratio of $(P_{uprate}/P_{current})$.
- The flow rate change factor will be determined by the ratio of $(Flow_{uprate}/Flow_{current})$.

These thermal, pressure, and flow rate change factors were used in determining the acceptability of piping systems for SPU conditions.

For thermal, pressure, and flow rate change factors less than or equal to 1.0 (that is, the current condition envelopes or equals the SPU condition), the piping system was concluded to be acceptable for SPU conditions.

For thermal, pressure, and flow rate change factors greater than 1.00, additional evaluations were performed to address the specific increase in temperature, pressure and/or flow rate in order to document design basis compliance.

Applicable rupture postulation criteria and related design basis documents for Seabrook Station were reviewed and changes to piping system stress levels resulting from SPU were reconciled against these design basis documents. The evaluations performed concluded that the SPU does not result in any new or revised break locations, and the existing design basis for pipe break, jet impingement, and pipe whip considerations remains valid for SPU.

All impacted piping and supports were evaluated for changes in operating temperatures, pressures and flow rates resulting from SPU. The results of these evaluations concluded that all piping and supports continue to satisfy existing design basis requirements. Piping systems experiencing higher flow rates will be reviewed for flow induced vibration issues as part of the start-up testing program related to the overall implementation of SPU.

There were no change to any seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all equipment qualification remains valid and unaffected by the SPU.

The evaluations reconciling SPU conditions have addressed applicable piping systems for potential increases in steam hammer or water hammer loads. The main steam piping was evaluated to reconcile the increased loads resulting from a turbine stop valve closure event. The feedwater piping was evaluated to reconcile the loads resulting from a feedwater pump trip event. The evaluations performed concluded that these piping systems can withstand the steam hammer/water hammer loads associated with SPU conditions.

The results of the BOP piping system evaluations indicate that the piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions.

For those piping systems that required additional analyses (change factor greater than 1.0), a summary of revised stress levels corresponding to SPU conditions is provided in LAR Table 8.5-1. The results presented include existing stress levels (i.e., current), revised pipe stress levels for SPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile SPU conditions. The stress results reported have incorporated thermal expansion and fluid transient increases that were reconciled as part of the SPU evaluations. The design margin provided is based on the ratio of the calculated stress divided by the allowable stress.

8.5.1.3 CONCLUSION

The BOP piping and pipe support evaluations performed conclude that the piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions. The piping evaluations also concluded that the Main Steam and Feedwater Systems can withstand the steam hammer/water hammer loads associated with SPU conditions. The piping and support systems will continue to meet their licensing basis and satisfy the requirements of General Design Criteria 1, 2, 4, 14 and 15.

The evaluations also concluded that the SPU does not result in any new or revised break locations, and the design basis for pipe break, jet impingement, and pipe whip considerations remains valid for power uprate. Hence, for rupture postulation issues, the piping and support systems continue to meet their licensing basis and satisfy the requirements of General Design Criteria 4.

There were no changes to any seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all equipment qualification remains valid and unaffected by the SPU. Therefore, the existing licensing basis for the seismic qualification of equipment remains valid and satisfies the requirements of General Design Criteria 1, 2, 4, 14 and 30.

8.5.2 NSSS PIPING AND SUPPORTS

8.5.2.1 DESCRIPTION

Piping and structural analyses are discussed in Seabrook Station UFSAR Chapter 3. The evaluations of piping and supports demonstrate that the current design is acceptable to support operation for an analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level).

The NSSS piping systems evaluated for SPU conditions included the following piping systems.

- Residual Heat Removal
- Chemical and Volume Control
- Containment Spray
- Safety Injection
- Spent Fuel Pool Cooling
- Combustible Gas Control
- Emergency Feedwater
- Reactor Coolant System (pipe support embedment loads). Reactor Coolant System piping and supports are evaluated in LAR Section 5.5.

8.5.2.2 EVALUATION

System operation at SPU conditions generally results in increased pipe stress levels, pipe support loads and equipment nozzle loads due to slightly higher operating temperatures, pressures and flow rates internal to the piping. The NSSS piping systems affected by SPU were evaluated as follows.

Pre-uprate and SPU operating data (operating temperature, pressure, and flow rate) were obtained from NSSS system analysis described in LAR Sections 4.1, 6.1, 6.4 and 8.4, and calculations.

Applicable rupture postulation criteria and related design basis documents for Seabrook Station were reviewed and any changes to piping system stress levels resulting from SPU were reconciled against these design basis documents. The evaluations performed concluded that the SPU does not result in any new or revised break locations, and the existing design basis for pipe break, jet impingement, and pipe whip considerations remains valid for SPU.

All impacted piping and supports were evaluated for changes in operating temperatures, pressures and flow rates resulting from SPU. The results of these evaluations concluded that all piping and supports continue to satisfy existing design basis requirements. Piping systems experiencing higher flow rates will be reviewed for flow induced vibration issues as part of the start-up testing program related to the overall implementation of SPU.

There were no change to any seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all equipment qualification remains valid and unaffected by the SPU.

The evaluations reconciling SPU conditions have addressed applicable piping systems for potential increases in water hammer loads. The evaluations performed concluded that these piping systems can withstand the water hammer loads associated with SPU conditions.

The results of the NSSS piping system evaluations that were performed concluded that the NSSS piping systems were not significantly impacted by the SPU.

8.5.2.3 CONCLUSION

The NSSS piping and pipe support evaluations performed conclude that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions. The piping and support systems will continue to meet their licensing basis and satisfy the requirements of GDCs-1, 2, 4, 14 and 15.

The evaluations also concluded that the SPU does not result in any new or revised break locations, and the design basis for pipe break, jet impingement, and pipe whip considerations remains valid for power uprate. Hence, for rupture postulation issues, the piping and support systems continue to meet their licensing basis and satisfy the requirements of GDC- 4.

There were no changes to any seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all equipment qualification remains valid and unaffected by the SPU. Therefore, the existing licensing basis for the seismic qualification of equipment remains valid and satisfies the requirements of GDC-1, 2, 4, 14 and 30.

TABLE 8.5-1
STRESS SUMMARY AT SPU CONDITIONS

Piping Analysis Description	Loading Condition (Note 1&2)	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Percentage of Allowable (Note 3)
Main Steam inside containment lines 4000 and 4001	Equation 9U/E	15,977	17,734	21,000	84
	Equation 9F	26,374	29,275	31,500	93
Main Steam inside containment lines 4002 and 4003	Equation 9U/E	14,664	16,277	21,000	76
	Equation 9F	25,738	28,569	31,500	91
Main Steam outside containment lines 4000, 4001, 4002, 4003	Equation 9U/E	19,388	20,708	21,000	99
Main Steam outside containment lines 4000 and 4001	Equation 9U/E	19,857	20,601	21,000	98
	Equation 9F	28,251	31,359	31,500	99
Main Steam outside containment lines 4002 and 4003	Equation 9U/E	18,385	20,407	21,000	97
	Equation 9F	24,476	27,168	31,500	86
Main Steam outside containment line 4014	Equation 10	6,098	6,342	22,500	28
Feedwater inside containment lines 4606 and 4607	Equation 9U/E	16,343	17,650	18,000	98
	Equation 9F	25,221	26,504	27,000	98
Feedwater inside containment lines 4608 and 4609	Equation 9U/E	17,278	17,458	18,000	97
	Equation 9F	25,747	25,928	27,000	96
Feedwater outside containment lines 4606, 4607, 4608 and 4609	Equation 9U/E	14,863	16,052	18,000	89
Feedwater outside containment line 4006	Equation 9U/E	15,027	16,229	18,000	90
	Equation 9F	23,719	25,617	27,000	95

NOTES:

(1) Stress data for both ASME Section III and B31.1 designed systems are reported using Equations 9U/E, 9F, 10 and 11 corresponding to ASME Section III, Subarticle NC/ND-3650 for consistency/clarity purposes. For applicable B31.1 designed systems, ASME Equations 9, 10 & 11 correspond to B31.1 Equations 12, 13 & 14 of Paragraph 104.8 respectively.

(2) The stress reported for "Equation 9U/E" is the maximum stress from either Equation 9 Upset (9U) or Equation 9 Emergency (9E).

(3) Percentage of allowable reported is based on the ratio of SPU stress divided by the Allowable stress.

TABLE 8.5-1 (continued)
STRESS SUMMARY AT SPU CONDITIONS

Piping Analysis Description	Loading Condition (Note 1&2)	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Percentage of Allowable (Note 3)
Feedwater outside containment line 4007	Equation 9U/E	16,508	16,675	18,000	93
	Equation 9F	22,449	24,245	27,000	90
Feedwater outside containment line 4008	Equation 9U/E	13,884	14,995	18,000	83
	Equation 9F	22,026	23,788	27,000	88
Feedwater outside containment line 4009	Equation 9U/E	13,747	14,847	18,000	83
	Equation 9F	22,530	24,332	27,000	90
Feedwater heaters E26A/B to header	Equation 9U/E	13,461	14,538	18,000	81
	Equation 11	32,240	32,562	37,500	87
Feedwater pumps to heaters E26A/B	Equation 9U/E	9,223	9,961	18,000	55
	Equation 10	19,209	19,401	22,500	86
Feedwater branch piping	Equation 10	8,438	8,522	22,500	38
Feedwater branch piping	Equation 9U/E	11,871	12,821	18,000	71
Feedwater heaters E21A/B/C to E23A/B/C	Equation 10	13,962	18,290	22,500	81
Feedwater heaters E22A/B/C to E23A/B/C	Equation 10	5,656	5,939	22,500	26
Feedwater heaters E23A/B/C to E24A/B/C	Equation 10	6,704	6,972	22,500	31
Feedwater heaters E24A/B/C to E25A/B	Equation 10	9,370	9,651	22,500	43
Extraction Steam to heaters E23A/B/C	Equation 10	11,505	12,310	22,500	55
Extraction Steam to heaters E24A/B/C	Equation 10	7,791	8,336	22,500	37

NOTES:

(1) Stress data for both ASME Section III and B31.1 designed systems are reported using Equations 9U/E, 9F, 10 and 11 corresponding to ASME Section III, Subarticle NC/ND-3650 for consistency/clarity purposes. For applicable B31.1 designed systems, ASME Equations 9, 10 & 11 correspond to B31.1 Equations 12, 13 & 14 of Paragraph 104.8 respectively.

(2) The stress reported for "Equation 9U/E" is the maximum stress from either Equation 9 Upset (9U) or Equation 9 Emergency (9E).

(3) Percentage of allowable reported is based on the ratio of SPU stress divided by the Allowable stress.

TABLE 8.5-1 (continued)
STRESS SUMMARY AT SPU CONDITIONS

Piping Analysis Description	Loading Condition (Note 1&2)	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Percentage of Allowable (Note 3)
Extraction Steam to heaters E26A/B	Equation 10	6,756	6,891	22,500	31
Extraction Steam to heaters E25A/B	Equation 10	7,444	7,593	22,500	34
Heater Drain Lines from Heaters E24A/B/C to E23A/B/C	Equation 10	8.973	9,511	22,500	42
Heater Drain lines from heaters E23A/B/C to E22A/B/C	Equation 10	12,320	13,306	22,500	59
Heater Drain lines from heaters E22A/B/C to E21A/B/C	Equation 10	4,208	4,587	22,500	20
Heater Drain lines from heaters E26A/B to E25A/B	Equation 10	13,726	13,863	22,500	62
Heater Drain piping	Equation 9U/E	8,276	8,855	18,000	49
	Equation 10	20,864	21,281	22,500	95
Heater Drain piping	Equation 10	21,976	23,075	27,475	84
MSR Vents and Drains	Equation 10	17,612	17,788	22,500	79

NOTES:

(1) Stress data for both ASME Section III and B31.1 designed systems are reported using Equations 9U/E, 9F, 10 and 11 corresponding to ASME Section III, Subarticle NC/ND-3650 for consistency/clarity purposes. For applicable B31.1 designed systems, ASME Equations 9, 10 & 11 correspond to B31.1 Equations 12, 13 & 14 of Paragraph 104.8 respectively.

(2) The stress reported for "Equation 9U/E" is the maximum stress from either Equation 9 Upset (9U) or Equation 9 Emergency (9E).

(3) Percentage of allowable reported is based on the ratio of SPU stress divided by the Allowable stress.

8.6 STRUCTURAL

8.6.1 CONTAINMENT STRUCTURE

8.6.1.1 DESCRIPTION

The containment structure is described in Seabrook Station UFSAR Sections 3.8.1. The containment functional design is described in Seabrook Station UFSAR Section 6.2.1.1. The design basis containment pressure is 52 psig. The design basis liner temperature is 271°F.

8.6.1.2 EVALUATION

Containment pressure and temperature transient analyses performed at SPU conditions demonstrate that the design basis containment pressure and temperature at current power are bounding. Refer to LAR Subsection 6.4.3 and 6.4.5. Therefore, loads to the containment structure associated with LOCA and main steam line break for the current power condition remain limiting.

8.6.1.3 CONCLUSION

Loads to the containment structure associated with LOCA and main steam line break at current power remain limiting and loads at SPU are bounded. Therefore, there is no structural impact on the containment design at SPU.

Evaluation of the containment structure adequately accounts for pipe rupture pressure, temperature and dynamic effects at the proposed SPU condition, and ensures that the containment structure continues to meet the acceptance criteria (i.e., 10 CFR 50, Appendix A; General Design Criteria 4, 16 and 50).

8.6.2 CONTAINMENT SUB-COMPARTMENTS

8.6.2.1 DESCRIPTION

The containment sub-compartments are described in Seabrook Station UFSAR Sections 3.8.3. The functional design of the containment sub-compartments is described in Seabrook Station UFSAR Section 6.2.1.2.

8.6.2.2 EVALUATION

Based upon Leak-Before-Break, over pressurization of the reactor cavity and steam generator cubicles has been eliminated from the design basis and therefore, SPU has no impact on design of these cubicles. The remaining sub-compartment analyses (Pressurizer Compartment) at SPU are bounded by the original analyses. This conclusion is based on the results of the mass and energy determination at SPU, which concludes that the current mass and energy data are bounding. Refer to LAR Subsection 6.4.1 and 6.4.2. Therefore, loads to the containment sub-compartments associated with LOCA for the current power condition remain limiting.

8.6.2.3 CONCLUSION

Loads to the containment sub-compartments associated with LOCA at current power remain limiting and loads at SPU are bounded by the current power conditions. Therefore, there is no structural impact on the containment sub-compartment design at SPU.

Evaluation of the containment sub-compartments adequately accounts for pipe rupture pressure, temperature and dynamic effects at the proposed SPU condition, and ensures that the containment sub-compartments continue to meet the acceptance criteria (i.e., 10 CFR 50, Appendix A; General Design Criteria 4).

8.6.3 HIGH ENERGY LINE BREAK OUTSIDE CONTAINMENT

8.6.3.1 DESCRIPTION

Pipe rupture effects are described in Seabrook Station UFSAR Section 3.6. Appendix 3A of the Seabrook Station UFSAR summarizes the results of analysis of high energy line break outside the containment.

Potential impact of the SPU on safety related structures outside the containment is the increase in differential pressure, jet impingement, pipe whip loads, and temperature to structures due to high energy line break outside containment. The high energy piping outside containment considered in the high energy line break review include:

- Chemical Volume and Control System letdown line
- Steam Generator Blowdown lines
- Auxiliary Steam and Condensate lines
- Main Steam lines
- Feedwater lines
- Hot Water Heating lines

8.6.3.2 EVALUATION

High energy line break differential pressures at SPU conditions are bounded by the high energy line break differential pressures at current power. High energy line break temperatures at SPU conditions are bounded by the high energy line break temperatures at current power except for the Main Steam/Feedwater pipe chase areas. Pipe break analysis performed for the Main Steam/Feedwater pipe chase areas shows that the West and East pipe chase maximum temperatures increased from 325°F, for the existing condition, to 467.7°F for the SPU condition. This new analysis was performed assuming a pipe break size of 0.1 ft^2 pressurizing the pipe chase areas to just below the building blowout panels opening pressure, resulting in a conservative condition for evaluating the environmental conditions in the adjacent areas. A detailed review of the main steam and feedwater pipe chase design demonstrates that the Seabrook Station can achieve a safe shutdown under any

postulated superheated temperature profile due to a main steam line break in these areas. Refer to LAR Section 6.5. Therefore, loads to safety related structures required for safe shutdown associated with high energy line break outside containment for the current power condition remain limiting.

8.6.3.3 CONCLUSION

The implementation of SPU does not introduce high energy line break related loads exceeding the existing design loads or unacceptable conditions for safety related structures affected by high energy line break outside containment.

Evaluation of the safety related structures outside the containment adequately account for pipe rupture pressure, temperature and dynamic effects at the proposed SPU condition, and ensure that the safety related structures continue to meet the acceptance criteria (i.e., 10 CFR 50, Appendix A; General Design Criteria 4).

8.6.4 PIPE SUPPORT REACTIONS

8.6.4.1 DESCRIPTION

Pipe support reactions produce loading to structural elements that comprise the support structure for the piping systems. The structural elements that form the basis of the structural evaluation consist of major structural steel framing and cast-in-place concrete embedded plates. The only piping system support reactions identified that necessitated further structural evaluations were those for the Main Steam, Feedwater, Extraction Steam and Heater Drain Systems.

8.6.4.2 EVALUATION

Evaluation of pipe support reactions on structures was performed to compare the SPU values of reactions with the values at current power. For the pipe reactions, the existing design loads identified in the piping analyses for each support, were compared to the revised reaction accounting for SPU changes. No pipe support reactions on structural framing or embedded steel plates were identified in excess of existing margins or acceptable limits. Refer to LAR Section 8.5.

8.6.4.3 CONCLUSION

Based on existing margins available for structural components, SPU does not result in pipe support reactions on existing structures in excess of the current design loads or existing design margins for the indicated systems.

8.7 REFERENCES

8.4-1 FPL Energy Seabrook letter to NRC, NYN-03061, "LAR 03-02, Implementation of Alternative Source Terms," October 6, 2003

8.4-2 Seabrook Station letter to NRC, SBN-425, "Open Item Response (SRP 12.3.2, 12.3.4 and 12.5.1; Radiological Assessment Branch)," January 21, 1983

8.4-3 Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 95 to Facility Operating License No. NPF-86, FPL Energy Seabrook, LLC, Seabrook Station, Unit No. 1, Docket No. 50-443

SEABROOK STATION

SECTION 9.0

PROGRAMS

9.0 PROGRAMS

9.1 GENERIC ISSUES/PROGRAMS

The SPU has the potential to affect programs that were developed and implemented by station personnel to demonstrate that topical areas comply with various design and licensing requirements.

9.1.1 FIRE PROTECTION PROGRAM

The Fire Protection Program provides assurance through a defense–in-depth design, that a fire will not prevent the performance of the necessary plant safe shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The fire event safe shutdown design basis for Seabrook Station is that one train of systems necessary to achieve and maintain cold shutdown from either the control room or remote safe shutdown facility remains free of fire damage.

Systems and components required to maintain safe shutdown conditions at Seabrook Station are discussed in the Seabrook Station UFSAR, Section 3, Appendix R, Safe Shutdown Capability. The only SPU impact on the Seabrook Station safe shutdown analysis is due to the effect of increased decay heat. LAR Subsection 4.1.4.3.3 concludes that systems and components are adequately sized to meet 10 CFR 50 Appendix R safe shutdown regulatory requirements for the SPU. Therefore, no changes in the Fire Protection Program will be required for the SPU.

9.1.2 VALVE PROGRAMS

The design basis of the safety-related power-operated valves, motor (MOVs), air (AOVs), and solenoid (SOVs) were reviewed. The reviews considered the requirements of NRC Generic Letters 89-10 and 95-07 [References 9.1-1 and 9.1-2 respectively]. The design basis parameters included voltage, pressure, temperature, and differential pressure. These reviews concluded that:

- There are no changes to the design basis pressure or temperature for safety-related power operated valves.
- The bounding parameters used to establish the worst-case differential pressures for safety-related power operated valves were reviewed. Since the current worst-case differential pressures for the safety-related power operated valves remain bounding, the review concluded that existing valve actuators will adequately perform their intended design function after the SPU.
- There are no changes to the results of the current pressure locking and thermal binding evaluations.

Based on the above, the existing design basis for the power operated valves (MOVs, AOVs, and SOVs) bound operation at SPU conditions. Therefore, no changes to the valve programs will be required for the SPU.

9.1.3 FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion Program manages the aging effect of loss of material due to flow accelerated corrosion. The Flow Accelerated Corrosion Program predicts, detects, monitors, and mitigates flow accelerated corrosion in high energy carbon steel piping, and is based on industry guidelines and experience. The program includes analysis and baseline inspections; determination, evaluation, and corrective actions for affected components; and followup inspections. The program is implemented in accordance with NSAC-202L-R2 [Reference 9.1-3].

An evaluation of Seabrook Station high energy piping systems has been performed to identify changes in fluid conditions (e.g., pressures, temperatures, flows, steam quality, chemistry) resulting from the SPU. As a result of the SPU, most of the Seabrook Station fluid systems will experience flow increases less than approximately 10% with insignificant changes in fluid temperatures. Hence, flow accelerated corrosion rates are not expected to increase appreciably in the systems currently in the Flow Accelerated Corrosion Program. Additionally no new piping will require inclusion in the flow accelerated corrosion evaluations that are not already included in the Program.

In over 13 years of operation, Seabrook Station has not experienced excessive flow accelerated corrosion wall thinning or piping sections requiring replacement in fluid systems which have single phase fluid conditions (water or steam). However, the plant has experienced some flow accelerated corrosion wall thinning in two-phase flow systems, such as extraction steam and moisture separator drains. Some of the original carbon steel extraction steam system piping components susceptible to flow accelerated corrosion have been replaced with chrome-moly piping increasing their resistance to flow accelerated corrosion. The carbon steel moisture separator drain lines continue to be the piping most susceptible to flow accelerated corrosion and are periodically inspected. As a result of the SPU and moisture separator reheater modification to improve moisture removal efficiency, this piping will experience an approximately 30% increase from the current operating flow rate. (Note: As indicated on LAR Table 9.1.3-1, the Flow Accelerated Corrosion Program conservatively utilizes design flow values in lieu of current operating values.) Because of the previous flow accelerated corrosion experience in these lines and the flowrate increase noted above, this piping was specifically evaluated using the Seabrook Station flow accelerated corrosion Checworks Model.

The results of the evaluation are summarized below for several of the critical flow accelerated corrosion areas in these piping segments.

As summarized and demonstrated by LAR Table 9.1.3–1, the SPU will not significantly impact the flow accelerated corrosion wear rates such that new problem areas are expected to arise nor will the increase in wear rates challenge the current minimum wall thickness requirements.

As part of implementation of the SPU, the SPU fluid conditions will be utilized as input to Flow Accelerated Corrosion Program predictive models to establish and validate component erosion/wear rates. Because Seabrook Station does not

experience any significant flow accelerated corrosion problem areas today and the typical flow accelerated corrosion prone areas have been replaced with chrome – moly, the analysis summarized above has demonstrated that major changes to the scope of FAC inspections or their frequencies are not expected. If the implementation review does by chance identify new areas to be susceptible to flow accelerated corrosion, baseline inspections will be performed. Additionally, any current flow accelerated corrosion evaluations which predict marginally acceptable wall thickness at the end of the first SPU cycle will be reviewed for impact of SPU fluid conditions. Based upon this evaluation, inspections of those components will be performed prior to startup of the first SPU cycle, if required.

TABLE 9.1.3 – 1
MOISTURE SEPARATOR DRAIN PIPING FAC EVALUATION SUMMARY

Piping Segment Description	Current Flow (lb /hr) (1)	Current Maximum Wear rate	SPU Flow (lb /hr)	SPU Maximum Wear rate
Moisture seperator reheater "A" drain	0.39×10^6	5 Mils/Yr	0.42×10^6	7 Mils/Yr
Moisture seperator reheater "B" drain	0.39×10^6	9 Mils/Yr	0.42×10^6	11 Mils/Yr
Moisture seperator reheater "C" drain	0.39×10^6	4 Mils/Yr	0.42×10^6	5 Mils/Yr
Moisture seperator reheater "D" drain	0.39×10^6	9 Mils/Yr	0.42×10^6	10 Mils/Yr
Note 1 - Based on design values provided on the current Flow Accelerated Corrosion program heat balance diagram.				

9.2 EQUIPMENT QUALIFICATION PROGRAM

9.2.1 DESCRIPTION

The Seabrook Station environmental qualification of electrical and mechanical equipment is described in the Seabrook Station UFSAR Section 3.11. The Equipment Qualification Report, "Environmental Qualification of Electrical Equipment Important to Safety" has been submitted to the Nuclear Regulatory Commission separate from the UFSAR [Reference 9.2-1]. This report covers the station operations and maintenance Equipment Qualification Program. A Mechanical Equipment Qualification Report has also been submitted to the NRC as a separate document [Reference 9.2-2]. The values for the environmental parameters for the equipment qualification are provided in the Seabrook Station UFSAR Figure 3.11-1. The purpose of the Equipment Qualification evaluation is to demonstrate that the electrical and mechanical equipment remain qualified with the revised conditions for operation following implementation of the SPU.

Additionally, protective coatings (i.e., organic materials) inside containment provide a means for protecting surfaces that would be exposed to accident environments. The description of the organic materials are described in Seabrook Station UFSAR Sections 6.1(B).2 and 6.1(N).2 and meet the requirements of Regulatory Guide 1.54 [Reference 9.2-3].

Discussion regarding the tests and analyses used to demonstrate the seismic design of electrical and mechanical equipment is provided in Seabrook Station UFSAR Sections 3.7, 3.9, and 3.10. The primary input motions attributable to an earthquake are not impacted by the SPU. However, other parameter changes that do potentially impact seismic qualification are discussed in LAR Section 8.5.

9.2.2 EVALUATION

Evaluation of the environmental qualification of equipment in the Equipment Qualification Program demonstrates that the equipment will remain qualified under SPU conditions, but with minor changes to the environments the equipment will experience at SPU conditions . The qualification evaluation reviewed the changes to equipment environments resulting from anticipated operational occurrences, normal operation, off-normal operation, accidents and post-accident conditions.

Comparisons were made between the environmental conditions to which the equipment is currently qualified and the environmental conditions that will be present following the implementation of the SPU. Where there is a qualification challenge, further evaluations specific for the equipment were performed.

The evaluations demonstrated the continued qualification of the equipment or identified the requirement for equipment upgrades or changes by ensuring that the margins required by IEEE 323, 1974 and the Equipment Qualification Program are maintained. The acceptance criterion is the continued qualification of the equipment under the requirements of 10 CFR 50.49.

For the protective coatings (i.e., organic materials) inside containment, verify that the coatings will continue to meet the requirements of Regulatory Guide 1.54 [Reference 9.2-3].

9.2.2.1 INSIDE CONTAINMENT

Normal service conditions and operational occurrences for radiation, pressure, temperature and humidity do not change. Refer to LAR Subsection 8.4.15.2 for further discussion on normal shielding.

The SPU analysis of design bases accidents, discussed in LAR Subsections 6.4.3 and 6.4.5, demonstrates that the equipment qualification temperature profile bounds the SPU accident profile.

The pressure profile for the equipment qualification bounds the SPU pressure results calculated for the first 24 hours of the accident transient. However, the long-term pressure post accident exceeds the qualification pressure of 16.2 psia by 4.5 psi. This is acceptable since the qualification peak pressure is 66.7 psia. Pressure effects are generally stress related rather than age degradation related. Qualification to the high-pressure peak ensures that there are no stress related component failures. Devices susceptible to moisture intrusion are sealed and the peak pressure qualifies the integrity of the seal.

The radiation doses inside Containment are increased due to both the SPU and to other analysis changes from the original qualification. See LAR Subsection 8.4.15.2.4 for additional details. Revised total integrated doses that combine normal operation service conditions with the design bases accidents have been compared to the original qualification value. The results of the comparison show that the equipment continues to be qualified at the SPU conditions, and thus, continues to meet the requirements of 10 CFR 50.49.

Other parameters that affect the qualification of equipment are humidity, submergence and chemical spray. Humidity and submergence do not change per LAR Subsections 6.1.4 and 10.3. The chemical concentration of the boron in the sprays and injection paths is reduced slightly but the pH value remains within the acceptable range of the Standard Review Plan and the qualification of the equipment.

Protective coatings (i.e., organic material) inside the containment comply with the design basis accident testing requirements of ANSI N101.2. As a result of the SPU, the containment coatings will be exposed to slightly higher radiation levels (refer to LAR Subsection 8.4.15.2.4) but will not exceed the design basis accident testing values specified in ANSI N101.2. The other design basis accident conditions, such as peak temperature, peak pressure, and the chemical environments will remain bounding as a result of the SPU. Refer to LAR Subsections 6.1.4, 6.4.3, and 6.4.5. Therefore the protective coatings (i.e., organic material) will continue to meet the requirements of Regulatory Guide 1.54 [Reference 9.2-3] and will be acceptable following implementation of the SPU.

9.2.2.2 OUTSIDE CONTAINMENT

Normal service conditions and operational occurrences for temperature and humidity do not change following implementation of the SPU. The normal radiation dose for many rooms and cubicles will increase by a factor of 1.7 to account for changes from the original values and input parameters used in their design. Refer to LAR Subsection 8.4.15.2.3 for discussion of normal radiation doses.

The accident environments outside Containment have been evaluated. The SPU analysis for the east and west pipe chase areas resulted in increased temperatures as described in LAR Subsection 6.5.2. The existing plant response analysis, however, remains valid. There are no changes to the qualification of equipment as a result of the high energy line breaks in this area.

For areas outside Containment with harsh radiation environments, Equipment Qualification Program equipment total integrated doses have been scaled up, where applicable, to account for increases in normal operating and post accident radiation levels as a result of SPU. The increases in the Equipment Qualification Program equipment total integrated doses are then compared to the equipment qualification doses. The results of the comparison show that the Equipment Qualification Program electrical and mechanical equipment continue to be qualified at SPU conditions and thus, continue to meet the requirements of 10 CFR 50.49

9.2.3 CONCLUSION

The electrical and mechanical equipment have been evaluated for SPU environmental conditions during normal operation operational occurrences and following design basis accidents. The SPU evaluation concludes that the equipment is capable of performing its safety function under the environmental conditions that could result from design basis accidents. The evaluation indicates that the equipment in the Equipment Qualification Program continues to be qualified in accordance with 10 CFR 50.49.

The protective coatings (i.e., organic material) inside containment will continue to meet the requirements of Regulator Guide 1.54, Revision 0 and will be acceptable following implementation of the SPU.

The SPU does not impact the input criteria used for the seismic design and qualification of Seabrook Station electrical and mechanical equipment. Consequently, this equipment will continue to meet the requirements of General Design Criteria 2 following the implementation of the SPU.

9.3 REFERENCES

9.1-1 U. S. NRC Generic Letter 89-10, "Safety-Related (1) Motor-Operated Valve Testing And Surveillance (Generic Letter No. 89-10) - 10 CFR 50.54(f)," June 28, 1989.

9.1-2 U. S. NRC Generic Letter 95-07, "Pressure Locking And Thermal Binding Of Safety-Related Power-Operated Gate Valves." August 17, 1995.

9.1-3 NSAC-202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program, Electric Power Research Institute," April 8, 1999.

9.2-1 PSNH letter SBN-866, dated 10/31/85.

9.2-2 PSNH letter SBN-608, dated 1/5/84.

9.2-3 Regulatory Guide 1.54, Revision 0, Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants, June 1973.

SEABROOK STATION

SECTION 10.0

MISCELLANEOUS TOPICS

10.0 MISCELLANEOUS TOPICS

10.1 MID-LOOP OPERATION

Mid-loop operation is discussed in Section 4.4.6.6 of the Seabrook Station UFSAR. This section, entitled "Instrumentation for Mid-loop Operation" summarizes the plant equipment, instrumentation, and procedures that are used to comply with the recommendations of Generic Letter 88-17, Loss of Decay Heat Removal [Reference 10.1-1]. This generic letter applies during shutdown when the water level is at reduced inventory (3 feet or more below the vessel flange), which also encompasses mid-loop (when the water level is below the top of the loop piping).

As a result of the SPU, the decay heat at a given time after shutdown would increase, roughly in proportion to the change in the SPU. This would in turn reduce the time to boiling and time to core uncovery following a postulated loss of Residual Heat Removal cooling. However, this change will not have a significant effect on basic shutdown safety provisions and the way the plant conducts mid-loop/reduced inventory operation. The normal operating procedures and methods for monitoring Reactor Coolant System level, core exit temperature, and Residual Heat Removal System performance would not change. Apart from revised time to boiling estimates, abnormal operating procedures as based on the Westinghouse Owners Group guidelines [Reference 10.1-2] would not be effected. Furthermore, administrative controls to ensure containment closure following a prolonged loss of Residual Heat Removal cooling would not be impacted since the time to core uncovery would remain relatively long (one hour or more).

During reduced inventory, one centrifugal charging pump would be available to restore inventory should a loss of Residual Heat Removal cooling occur during mid-loop or reduced inventory conditions. A secondary means of adding inventory to the Reactor Coolant System is via gravity flow from the refueling water storage tank. In addition, one safety injection pump would be available along with specified flow paths for adding Reactor Coolant System inventory, to either the hot legs or cold legs, to maintain core cooling in the event of a prolonged loss of Residual Heat Removal cooling. The capability of adding inventory by these three means will not be affected by the SPU.

Based on this assessment, the Seabrook Station SPU will not have an adverse affect on mid-loop or reduced inventory operation at the Seabrook Station.

10.2 NATURAL CIRCULATION COOLDOWN

To demonstrate capability for natural circulation cooling, many license holders reference the Diablo Canyon natural circulation cooldown test performed in 1985 and provide justification that this test reflects the capability of their plant by comparing relevant parameters. These parameters include hydraulic resistances in the Reactor Coolant System, natural circulation driving heads, plus power levels, pressures and temperatures.

For the natural circulation cooling assessment, a methodology developed by the Westinghouse Owners Group for the Emergency Response Guidelines was applied for analytically determining the natural circulation flow rates and temperature differentials. The Emergency Response Guidelines have been used for development of the plant-specific Emergency Operating Procedures used at the Seabrook Station. Comparisons between Seabrook Station and Diablo Canyon were made to establish a basis for applying the Diablo Canyon results to Seabrook Station. Results for the natural circulation flow rates and temperature differentials were extended for the Seabrook Station SPU. Acceptable results were found for natural circulation cooling during the hot standby period.

The capacities of the atmospheric steam dump valves were also evaluated to determine whether or not they have been sized with sufficient margin to allow cooldown of the Reactor Coolant System to Residual Heat Removal cut-in conditions within a reasonable time frame. The results indicated that the capacities of the atmospheric steam dump valves are sufficient to satisfy these conditions with full power operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) for an extended period of time.

The capacities of the atmospheric steam dump valves were also evaluated to determine whether or not they have been sized with sufficient margin to allow cooldown of the Reactor Coolant System to Residual Heat Removal cut-in conditions (~400 psig, and less than 350°F in the Reactor Coolant System) within a reasonable time frame. This cooldown can be completed in 9 hours at the maximum rate allowable per Emergency Operating Procedure ES-0.2, Natural Circulation Cooldown, (50°F/hr), including 4 hours at hot standby. Allowing for cooldown at less than the maximum allowable rate, 9 to 10 hours would be appropriate and in agreement with the time frame noted in Section 5.4.7 of the Seabrook Station UFSAR. This conservatively assumes a decay heat rate based on use of the ANSI/ANS-5.1-1979 decay heat standard, including +2 sigma uncertainty, with full power operation at the analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) for an extended period of time.

Therefore, by demonstrating the natural circulation flow rates and temperature differentials are reasonable and that the atmospheric steam dump valves are adequately sized to allow cooldown to Residual Heat Removal cut in conditions within the desired time frame, it is concluded that full power operation at the

analyzed SPU core power level of 3659 MWt (3678 MWt NSSS power level) does not adversely affect the natural circulation cooldown capability of Seabrook Station.

10.3 INTERNAL FLOODING

The existing plant evaluations for flooding conditions inside containment, as well as in various other plant locations were reviewed to identify any changes related to the SPU. These current evaluations are summarized in Seabrook Station UFSAR Sections 3.6, and Appendix 3A.

The existing analysis for the inside containment maximum water level is based on a design basis Loss of Coolant Accident (LOCA). The volumes of water added into the containment during a LOCA (e.g. refueling water storage tank, accumulators, Reactor Coolant System, spray additive tank) are unchanged. Therefore, the maximum containment water level following a design basis LOCA is not affected by the SPU. Because there are no changes to the operating / design parameters which formed the basis for the current flooding evaluations, the performance of systems, structures, and components that are important to safety will remain acceptable and bounded for the SPU.

The existing flooding analysis for other plant locations (including the Primary Auxiliary Building, Diesel Generator Building, equipment vaults and pipe chases, pump houses, and the Control Building) are not affected by the SPU. The system parameters, which formed the basis of the existing flooding evaluations, do not change as a result of the SPU.

The systems, structures, and components important to safety will therefore continue to be protected from flooding and will continue to meet the requirements of General Design Criteria 2 following implementation of the SPU.

10.4 HIGH ENERGY LINE BREAK / JET IMPINGEMENT

High energy line break analysis was reviewed to ensure acceptability for the SPU conditions. Appendix 3A of the Seabrook Station UFSAR summarizes the results of the failure mode and effects analysis of breaks in high energy piping systems. Seabrook Station UFSAR Section 3.6(B) addresses protection against dynamic effects associated with the postulated rupture of piping (LAR Section 8.5). Seabrook Station UFSAR Section 6.2 addresses pipe breaks inside containment.

Most of the existing high energy line break analysis is not affected by the SPU because the system operating and design conditions do not change. Therefore, the mass and energy release from breaks in these systems remains bounded by the current analysis. These systems include:

- Feedwater / main steam line break bounds the high energy line break impacts
- Chemical and Volume Control (letdown line) – SPU mass and energy flow rates are bounded by current analysis
- Steam Generator Blowdown lines – No load and normal system operating conditions do not change from current high energy line break analysis
- Auxiliary Steam and condensate return lines – System operating conditions are not impacted by SPU and therefore do not change from current high energy line break analysis
- Hot Water Heating lines – System operating conditions are not impacted by SPU and therefore do not change from current high energy line break analysis

The results of a main steam line break were demonstrated to be acceptable for the SPU. Refer to LAR Section 6.5.

Pipe break (rupture) locations and dynamic effects (General Design Criteria 4) are acceptable for the SPU and are addressed in LAR Section 8.5.

10.5 PROBABILISTIC SAFETY ASSESSMENT

The Seabrook Station SPU is small and incremental in nature, and will not result in significant changes in risk. This SPU LAR is not characterized as a risk-informed request. Guidance on the use of risk information in license amendment reviews that are not risk-informed was published in Nuclear Regulatory Commission Regulatory Issue Summary 2001-02 [Reference 10.5-1]. This guidance outlines a process that will be followed by the NRC if a non-risk informed submittal is believed to have a potential for a large increase in risk, to the degree that existing regulations do not provide adequate protection of the public health and safety. Compliance with existing NRC regulations will continue to assure adequate protection of public health and safety. The existing Seabrook Station Probabilistic Safety Study model will be updated as necessary to reflect the changes in plant design and operation due to the SPU. The impact on the PSA model is expected to be minimal and to primarily impact the shutdown plant operating states for the slightly increased decay heat. Updating the probabilistic safety assessment model will be done through the normal probabilistic safety assessment update process, after the modifications have been completed to the plant. This process assures that the probabilistic safety assessment continues to reflect the as-built and as-operated condition of the plant.

10.6 MODIFICATIONS

As part of the Seabrook Station SPU, modifications to support the SPU and to improve station performance are being implemented.

10.6.1 MODIFICATIONS REQUIRED FOR THE SPU

The high pressure turbine steam path is being modified to provide sufficient steam flow for the SPU. This is being accomplished by modifying the high pressure turbine rotor and replacing the fixed diaphragms.

Instrument and controls setpoint changes necessary to support the SPU are listed below:

- Change overtemperature ΔT setpoint.
- Change overpower ΔT setpoint.
- Change T_{avg} from high loop to average T_{avg}.
- Change steam generator low-low level setpoint.
- Re-span steam generator level transmitters.
- Change pressurizer level program.
- Change scaling for turbine impulse pressure to power, T_{ref}.
- Change loss of load interlocks, P13, C5, and steam dump control.
- Re-span steam flow transmitters.
- Re-band the main steam and feedwater flow indication in the Control Room normal operating (green band) band to address changes in feedwater flow.
- Modify scaling and indicator for generator megawatt meter on main control board.

10.6.2 ADDITIONAL MODIFICATIONS

Additional modifications are being performed to improve margins, plant performance, and efficiency. These modifications are not required to support the Seabrook Station SPU and are provided for information only. These modifications include:

- Replacing the moisture separator reheater internals with a new four pass system.
- Modifying the condensate pumps to provide additional flow and pressure to the steam generator feedwater pumps.
- Modifying the main feedwater pump turbine speed controller to allow the main feed pump speed to remain the same with the increase in pump differential pressure.

10.7 REFERENCES

10.1-1 U. S. NRC Generic Letter 88-17, "Loss of Decay Heat Removal," October 17, 1988.

10.1-2 Westinghouse Owners Group Abnormal Response Guideline and Background Information for ARG-1, "Loss of RHR While Operating at Mid-Loop Conditions," Revision 1, issued via WOG-96-093, June 6, 1996

10.5-1 U. S. NRC Regulatory Issue Summary 2001-02, "Guidance on Risk-Informed Decision Making in License Amendment Reviews," January 18, 2001.

SEABROOK STATION

SECTION 11.0

IMPACT ON OPERATIONS

11.0 IMPACT ON OPERATIONS

The impact of the Stretch Power Uprate (SPU) on human factors and plant operations has been assessed and is discussed in the following sections. The guidance on evaluating human factors effects requires a review of the following aspects :

1. Changes in Emergency and Abnormal Operating Procedures

   Describe how the proposed SPU will change the plant emergency and abnormal operating procedures.

2. Changes to Operator Actions Sensitive to the SPU

   Describe any new operator actions needed as a result of the proposed SPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the uprate.

3. Changes to Control Room Controls, Displays and Alarms

   Describe any changes the proposed SPU will have on the operator interfaces for control room controls, displays, and alarms. Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the SPU and how operators are tested to determine that they can use the instruments reliably.

4. Changes on the Safety Parameter Display System

   Describe any changes the proposed SPU will have on the Safety Parameter Display System. How will the operators know of the changes?

5. Changes to the Operator Training Program and the Control Room Simulator

   Describe any changes the proposed SPU will have on the operator training program and the plant referenced control room simulator, and provide the implementation schedule for making the changes.

The areas discussed are procedures, training, control room and simulator, and human factors.

11.1 IMPACT ON OPERATIONS DEPARTMENT PROCEDURES

Operation at SPU conditions will result in changes to the plant's response during transients. These plant response changes are expected to result in minor adjustments to some Emergency Operating Procedures and Abnormal Operating Procedures.

These Emergency and Abnormal Operating Procedures changes will not render ineffective any credited operator actions or mitigation strategies.

The SPU will result in changes in normal operations procedures, such as surveillance tests, general operating, and alarm response procedures. Any required

procedure changes will be identified, incorporated, reviewed and implemented before operation at the uprated power level.

11.2 IMPACT ON TRAINING

The Operations Department staff will be trained on the required modifications, Technical Specification changes, procedural changes, as well as the changes in plant response to transients and accident scenarios prior to implementation of the SPU. This will assure that the Operations Department staff receives the required training for continued safe and reliable operations. SPU related training needs for other departments will be developed and carried out as appropriate.

11.3 IMPACT ON THE CONTROL ROOM AND SIMULATOR

The SPU will have a limited impact on the operator interfaces for control room displays, controls, and alarms. The plant modification process will implement the required changes through normal quality program controls and the design control program. Control room indications have "band markings," that are controlled by the Operation's Department administrative control procedures and plant design control procedures. The band markings, which are mimicked in the Simulator, indicate normal operating limits, abnormal operating limits or Engineered Safety Feature actuation setpoints. The plant change packages for the uprate that identify control room changes will be processed in accordance with approved plant procedures. Training on Technical Specification changes affecting control room indications and alarms will be completed prior to implementation of the uprate.

11.4 HUMAN FACTORS

As appropriate, instrument alteration or replacement will be determined from an evaluation of Control Room instrumentation affected by the SPU. Affected instruments are evaluated to determine if expected indications would be within the optimal range for human factors considerations. Where appropriate, instrument replacement, scaling and band marking changes will be implemented as described in LAR Section 11.3. Any changes made to the Main Control Board will also be made in the simulator.

SEABROOK STATION

SECTION 12.0

TESTING

12.0 TESTING

Tests will be carried out to demonstrate that the Seabrook Station SPU and plant modifications have been adequately designed and implemented. A power ascension testing procedure will be developed and executed to provide assurance that the plant can be operated safely at the proposed higher power level. The test procedure results will be documented and submitted to the Nuclear Regulatory Commission in a startup report consistent with the requirements of the Seabrook Station Technical Specifications Section 6.8.1.1. The test procedure will address the performance of the modifications on an individual and integrated plant basis as appropriate. Individual modification test procedures will be developed in conjunction with vendors performing these modifications. The test procedures will be reviewed as directed by the site quality program.

The initial startup test program for Seabrook Station is summarized in Table 14.2.5 of the Seabrook Station UFSAR. The integrated test program for the Seabrook Station SPU will be developed using this table as a guide. Note that the individual tests identified below may differ in scope from those of the same name identified in Seabrook Station UFSAR Table 14.2.5. The test program will consist of a combination of normal surveillances and startup testing, and special testing for the SPU.

Testing performed as part of normal surveillances and startup testing will include:

- Core loading prerequisites
- Initial core loading
- Rod drop time measurements
- Rod position indication
- Reactor Coolant System flow measurement
- Operational alignment of nuclear instrumentation
- Operational alignment of process temperature instrumentation
- Initial criticality
- Boron endpoint measurement
- Isothermal temperature coefficient measurement
- Control rod worth measurement
- Thermal power measurement and statepoint data collection including calorimetric normalization
- Core performance evaluation
- Axial flux difference instrumentation calibration
- Loss of offsite power testing (integrated safeguards testing)

- Post-modification testing as required by the design change process including setpoint verification

Special testing planned for the SPU will include:

- Startup adjustments of the Reactor Control System
- Calibration of steam and feedwater flow instrumentation
- Steam generator moisture carryover measurement
- NSSS acceptance testing
- Turbine generator startup testing which will include a modified ASME PTC-6 test
- Flow-induced vibration monitoring
- Secondary system monitoring

SEABROOK STATION

SECTION 13.0

ENVIRONMENTAL EVALUATION

13.0 ENVIRONMENTAL EVALUATION

13.1 DESCRIPTION

The Environmental Impacts Review examined the environmental effluent discharge permit limits to assess the impact of the SPU. Radiological environmental impacts due to the SPU are addressed in a LAR Section 6.6 and LAR Subsection 8.4.15.2.1, and summarized herein.

The NRC originally evaluated environmental issues associated with the issuance of the Seabrook operating license in the Final Environmental Statement for Seabrook [Reference 13.1-1]. The Final Environmental Statement is considered a historical licensing document that will not be revised. However, the bases for the conclusion in the Final Environmental Statement are maintained through the operating license and the National Pollutant Discharge Elimination System permit.

The Final Environmental Statement concluded that, after weighing the environmental, economic, technical, and other benefits against environmental costs and considering available alternatives, the issuance of an operating license was an acceptable action. The Final Environmental Statement conclusions are not impacted as a result of the SPU.

The environmental review conducted for the SPU assessed the National Pollutant Discharge Elimination System permit limits [Reference 13.1-2], the Seabrook Environmental Report [Reference 13.1-3], and the Seabrook Final Environmental Statement. This assessment included determining whether the SPU would cause the plant to exceed non-radiological National Pollutant Discharge Elimination System permit limits, 10 CFR 50 Appendix I radiological release limits [Reference 13.1-4], or affect the conclusions reached in the Final Environmental Statement.

13.2 EVALUATION

The National Pollutant Discharge Elimination System permit flow and temperature rise limits will remain satisfied under SPU conditions, as shown in LAR Table 13.2-1.

The current and predicted SPU temperature rise values between the intake and discharge transition structures in LAR Table 13.2-1 are nominal design heat balance values. During the November to June time period each year, when Circulating Water intake temperatures are colder, a small percentage of the heated discharge water is recirculated back to the intake to moderate the cold intake water temperature, in order to optimize condenser pressure and maximize the plant's electrical output. This recirculation mode increases the discharge water temperature and therefore, the temperature rise between the intake and discharge transition structures is also increased. As is current practice, the recirculation of heated discharge water under SPU conditions will be controlled to comply with the National Pollutant Discharge Elimination System Permit limits.

Chemical discharges including residual chlorine from Circulating and Service Water treatments, and Steam Generator Blowdown will remain within existing permit limits.

The radiological environmental impact for normal operation addressed in LAR Subsection 8.4.15.2.1 concludes that SPU will have no significant impact on the expected annual radwaste effluent releases/dose since doses remain a small percentage of allowable Appendix I limits. In addition, the assessment concludes that the estimated doses following the SPU remain below those presented as part of the original license in the Seabrook Final Environmental Statement.

The radiological environmental impact for accidents is addressed in LAR Section 6.6 and concludes that the environmental consequences of accidents due to the SPU remain within regulatory limits.

13.3 CONCLUSION

This assessment concludes that the stretch power uprate will not cause the plant to exceed non-radiological National Pollutant Discharge Elimination System permit limits nor the 10 CFR 50 Appendix I radiological release limits. In addition, the assessment concludes the SPU will not affect the conclusions reached in the Final Environmental Statement. As a result of this assessment, it can be concluded that the SPU will have no significant impact on the environment.

13.4 REFERENCES

13.1-1 NUREG-0895, "Final Environmental Statement related to the operation of Seabrook Station Units 1 and 2," December 1982.

13.1-2 NPDES Permit No. NH0020338, "Authorization to Discharge Under The National Pollutant Discharge Elimination System," Effective Date April 1, 2002.

13.1-3 Seabrook Station Environmental Report – Operating License Stage (ER-OL), June 29, 1981.

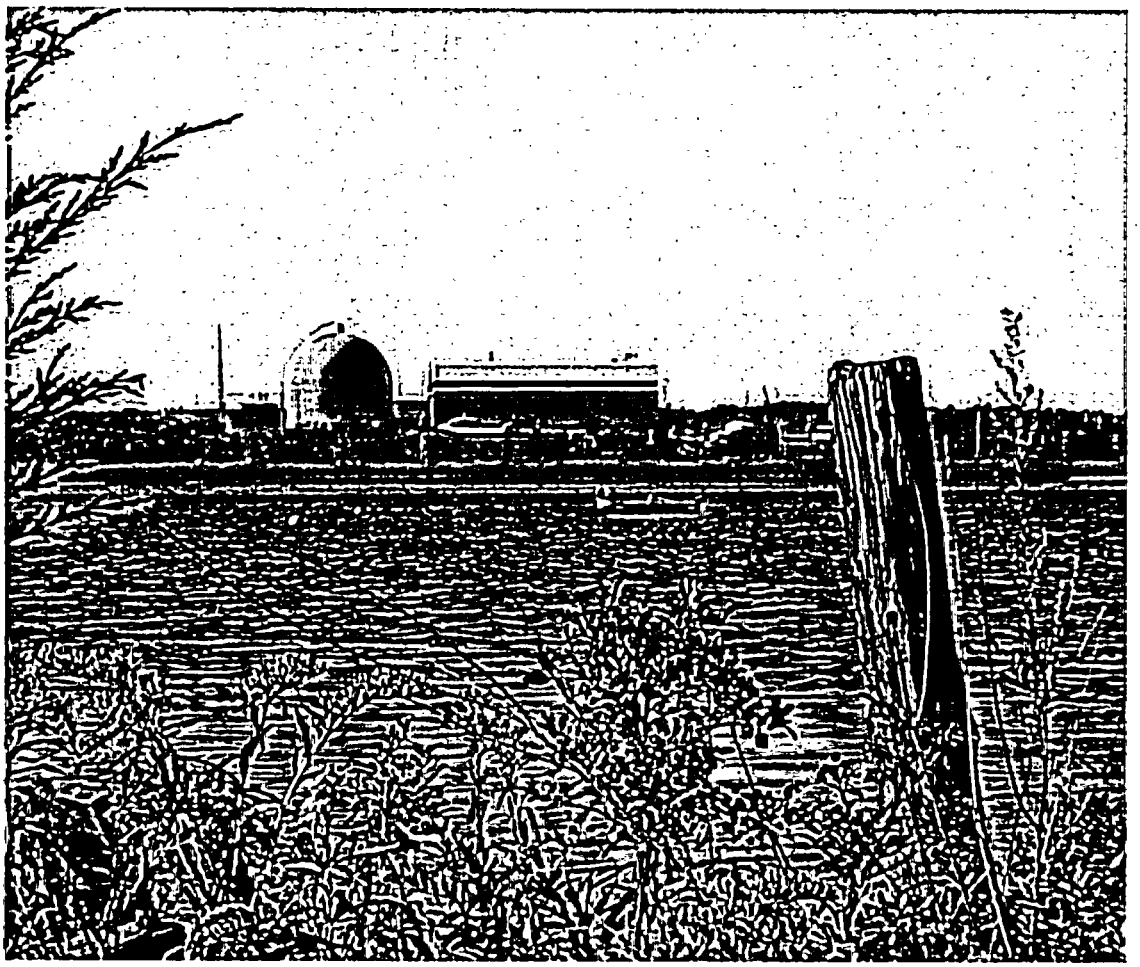
13.1-4 10 CFR 50 Appendix I, "Numerical Guidelines for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low As Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents."

TABLE 13.2-1
THERMAL DISCHARGE PARAMETERS

PARAMETER	PERMIT LIMITS (Average Monthly / Maximum Daily)	CURRENT OPERATION (nominal)	POWER UPRATE (nominal)
Flow (Million gallons per day)	720/720	<720	No change
Temperature rise (°F) Transition Structures (3 pumps)	39/41	31.5	33.7
Temperature rise (°F) Transition structures (2 pumps)	45/47	40.5	43.2
Temperature rise (°F) Discharge in near-field jet mixing region at surface	5 Monthly mean temperature rise at surface of receiving waters	4 Maximum monthly mean	4.24 Maximum monthly mean

Stretch Power Uprate
License Amendment Request

SEABROOK STATION



ATTACHMENT 2

MARKUP OF FACILITY OPERATING LICENSE
AND TECHNICAL SPECIFICATION PAGES

ATTACHMENT 2
MARKUP OF PROPOSED CHANGES TO THE FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATIONS

LIST OF PAGES CONTAINING PROPOSED CHANGES

Page Number	Current Amendment Number
Facility Operating License	
3	95
Technical Specifications	
1-5	81
2-1	
2-5	77
2-8	76
2-10	76
3/4 2-6b	76
3/4 2-10	
3/4 3-26	45
3/4 3-27	60
3/4 7-2	43
6-18B	
6-18C	
6-18D	76
Technical Specification Bases	
B 3/4 2-3	76
B 3/4 7-1	43

The attached marked up pages reflect the currently issued revision of the Facility Operating License NPF-86 and the Seabrook Station Technical Specifications and Bases. Pending changes are not reflected in the attached marked up pages.

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

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

(6) FPL Energy Seabrook, LLC, pursuant to the Act and 10 CFR 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility authorized herein; and

(7) DELETED

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I 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

FPL Energy Seabrook, LLC, is authorized to operate the facility at reactor core power levels not in excess of ~~3411~~ 3587 megawatts thermal (100% of rated power).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. ~~95~~, and the Environmental Protection Plan contained in Appendix B are incorporated into Facility License No. NPF-86. FPL Energy Seabrook shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) License Transfer to FPL Energy Seabrook, LLC

a. On the closing date(s) of the transfer of any ownership interests in Seabrook Station covered by the Order approving the transfer, FPL Energy Seabrook, LLC, shall obtain from each respective transferring owner all of the accumulated decommissioning trust funds for the facility, and ensure the deposit of such funds and additional funds, if necessary, into a decommissioning trust or trusts for Seabrook Station established by FPL Energy Seabrook, LLC, such that the amount of such funds deposited meets or exceeds the amount required under 10 CFR 50.75 with respect to the interest in Seabrook Station FPL Energy Seabrook, LLC, acquires on such dates(s).

PHYSICS TESTS

1.23 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation: (1) described in Chapter 14.0 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.24 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a nonisolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.

PROCESS CONTROL PROGRAM

1.25 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, tests, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State Regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.26 PURGE or PURGING shall be any controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

QUADRANT POWER TILT RATIO

1.27 QUADRANT POWER TILT RATIO 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. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER

1.28 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of ~~3411~~ 3587 Mwt.

REACTOR TRIP SYSTEM (RTS) RESPONSE TIME

1.29 The RTS RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its RTS Trip Setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

2.1 SAFETY LIMITS (SLs)

2.1.1 REACTOR CORE SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR; and the following SLs shall not be exceeded.

2.1.1.1 The departure from nucleate boiling ration (DNBR) shall be maintained greater than or equal to ~~1.17~~ 1.14 for the ~~WRB-1/WRB-2/~~ WRB-2M DNB correlations.

2.1.1.2 The peak fuel centerline temperature shall be maintained less than 5090°F, decreasing by 58°F per 10,000 MWD/MTU of burnup.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained less than or equal to 2735 psig.

2.1.3 SAFETY LIMIT VIOLATIONS:

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

2.1.3.2 If SL 2.1.2 is violated:

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

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

TABLE 2.1-1 (continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
11. Pressurizer Water Level - High	8.0	4.20	0.84	≤92% of instrument span	≤93.75% of instrument span
12. Reactor Coolant Flow – Low	N.A.	N.A.	N.A.	≥90% of indicated loop flow	≥89.6% of indicated loop flow
13. Steam Generator Water Level Low – Low	~~14.0~~ N.A	~~12.53~~	~~0.55~~	≥~~14.0~~ 20.0% of narrow range instrument span	≥~~12.6~~ 19.5% of narrow range instrument span
14. Undervoltage – Reactor Coolant Pumps	15.0	1.39	0	≥10,200 volts	≥9,822 volts
15. Underfrequency – Reactor Coolant Pumps	2.9	0	0	≥55.5 Hz	≥55.3 Hz
16. Turbine Trip					
a. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	≥500 psig	≥450 psig
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	≥1% open	≥1% open
17. Safety Injection Input from ESF	N.A.	N.A.	N.A.	N.A.	N.A.

TABLE 2.2-1 (Continued)

TABLE NOTATIONS

NOTE 1: (Continued)

T' → ~~T'~~ Indicated RCS T_{avg} at RATED THERMAL POWER, °F, (Calibration temperature for ΔT instrumentation, value specified in the COLR);

K_3 = Value specified in COLR;

P = Measured Pressurizer pressure, psig;

P' → ~~P'~~ = Nominal RCS operating pressure, psig, value specified in the COLR;

S = Laplace transform operator, s^{-1};

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers as specified in the COLR.

NOTE 2: Cycle dependent values for the channel's Allowable Value are specified in the COLR.

TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6 = Value specified in COLR,

T = As defined in Note 1,

T" → ~~T'~~[11] = Indicated T_{avg} at RATED THERMAL POWER, °F, (Calibration temperature for ΔT instrumentation, value specified in the COLR),

S = As defined in Note 1, and

$f_2(\Delta I)$ = A function of the indicated difference between the top and bottom detectors of the power-range neutron ion chambers as specified in the COLR.

NOTE 4: Cycle dependent values for the channel's Allowable Value are specified in the COLR.

g. The limits specified in Specification 4.2.2.2.c, 4.2.2.2.e, and 4.2.2.2.f above are not applicable in the following core plane regions:

1) Lower core region from 0 to ~~15%~~ 10, inclusive.

2) Upper core region from ~~85~~ 90 to 100%, inclusive.

4.2.2.3 When $F_Q(Z)$ is measured for reasons other than meeting the requirements of Specification 4.2.2.2, an overall measured $F_Q(Z)$ shall be obtained from a power distribution map and increased by 3% to account for manufacturing tolerances and further increased by 5% when using the moveable incore detectors or 5.21% when using the fixed incore detectors to account for measurement uncertainty.

4.2.2.4 (THIS SPECIFICATION NUMBER IS NOT USED)

3/4.2.5 DNB PARAMETERS

LIMIITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System T_{avg} is less than or equal to the limit specified in the COLR,

b. Pressurizer Pressure is greater than or equal to the limit specified in the COLR*, and

c. Reactor Coolant System Flow shall be:

1) ≥ ~~382,800~~ 374,400 gpm**, and,

2) ≥ ~~392,800~~ 383,800 gpm***

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the parameters shown above shall be verified to be within its limits at least once per 12 hours.

4.2.5.2 The RCS flow rate indicators shall be subjected to CHANNEL CALIBRATION at least once per 18 months.

4.2.5.3 The RCS total flow rate shall be determined by an approved method to be within its limit prior to operation above 95% of RATED THERMAL POWER after each fuel loading. The provisions of Specification 4.0.4 are not applicable for entry into MODE 1.

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* Limit not applicable during either THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% or RATED THERMAL POWER.

** Thermal Design Flow. An allowance for measurement uncertainty shall be made when comparing measured flow to Thermal Design Flow.

*** Minimum measured flow used in the Revised Thermal Design Procedure.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation (System)	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Containment Pressure--Hi-2	5.2	0.71	1.67	≤4.3 psig	≤5.3 psig
d. Steam Line Pressure--Low	13.1	10.71	1.63	≥585 psig	≥568 psig*
e. Steam Generator Pressure - Negative Rate--High	3.0	0.5	0	≤100 psi	≤123 psi**
5. Turbine Trip					
a. Automatic Actuation Logic Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. Steam Generator Water Level—High-High (P-14)	~~4.0~~ N.A.	~~2.24~~ N.A.	~~0.55~~	≤~~86.8~~% of narrow range instrument span. 90.8	≤~~87.7~~% of narrow range instrument span. 91.3
6. Feedwater Isolation					
a. Steam Generator Water Level--Hi-Hi-(P-14)	~~4.0~~	~~2.24~~	~~0.55~~	≤~~86.8~~% of narrow range instrument span.	≤~~87.7~~% of narrow range instrument span.
b. Safety Injection	N.A.	N.A.	N.A.	N.A.	N.A.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
7. Emergency Feedwater					
a. Manual Initiation					
(1) Motor driven pump	N.A.	N.A.	N.A.	N.A.	N.A.
(2) Turbine driven pump	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Steam Generator Water Level--Low-Low Start Motor-Driven Pump and Start Turbine-Driven Pump	~~14.0~~ N.A.	~~12.53~~ N.A.	~~0.55~~	~~≤14.0~~% 20.0 of narrow range instrument span.	~~≤12.6~~% 19.5 of narrow range instrument span.
d. Safety Injection Start Motor-Driven Pump and Turbine-Driven Pump	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.				
e. Loss-of-Offsite Power Start Motor-Driven Pump and Turbine-Driven Pump	See Item 9. for Loss-of-Offsite Power Setpoints and Allowable Values.				
8. Automatic Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. RWST Level -Low-Low Coincident With Safety Injection	4.0*** 2.1**** See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	1.0	2.8	120.478 gals.	≤121,521*** gals. ≥119,435**** gals.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING FOUR-LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT (PERCENT OF RATED THERMAL POWER)
1	~~66~~ 60
2	~~47~~ 42
3	~~28~~ 25

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER

Loop 1	Loop 2	Loop 3	Loop 4	LIFT SETTING* (± 3%)**	ORIFICE SIZE
V6	V22	V36	V50	1185 psig	16.0 sq. in.
V7	V23	V37	V51	1195 psig	16.0 sq. in.
V8	V24	V38	V52	1205 psig	16.0 sq. in.
V9	V25	V39	V53	1215 psig	16.0 sq. in.
V10	V26	V40	V54	1225 psig	16.0 sq. in.

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

** Within ±1% following main steam line Code safety valve testing.

6.8.1.6.b. (Continued)

Methodology for Specifications:
3.1.1.1 - SHUTDOWN MARGIN for MODES 1,2, 3, and 4
3.1.1.2 - SHUTDOWN MARGIN for MODE 5
3.1.1.3 - Moderator Temperature Coefficient
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

4. Seabrook Station Updated Final Safety Analysis Report, Section 15.4.6, "Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant System".

Methodology for Specifications:
3.1.1.1 - SHUTDOWN MARGIN for MODES 1, 2, 3, and 4
3.1.1.2 - SHUTDOWN MARGIN for MODE 5

5. YAEC-1241, "Thermal-Hydraulic Analysis of PWR Fuel Elements Using the CHIC-KIN Code", R. E. Helfrich, March, 1981.

WCAP-14565-~~P~~-A, (Proprietary), "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis", ~~April, 1997.~~ October,1999

~~Letter from T. H. Essig (NRC) to H. Sepp (Westinghouse), "Acceptance for Referencing of Licensing Topical Report WCAP-14565-P, (Proprietary), "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis", January, 1999.~~

WCAP-15025-~~P~~-A, Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17X17 Rod Bundles with Modified LPD Mixing Vane Grids, ~~February 1998.~~ April, 1999.

Methodology for Specification:
2.1 Safety Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor
3.2.5 DNB Parameters

6. YAEC-1849P, "Thermal-Hydraulic Analysis Methodology Using VIPRE-01 For PWR Applications," October, 1992.

WCAP-11397-P-A, (Proprietary), "Revised Thermal Design Procedure", April, 1989.

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

6.8.1.6.b. (Continued)

Methodology for Specification:
2.2.1 - Limiting Safety System Settings
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

7. YAEC-1854P, "Core Thermal Limit Protection Function Setpoint Methodology For Seabrook Station," October, 1992

~~WCAP-14551-P, (Proprietary), "Westinghouse Setpoint Methodology for Protection Systems, Seabrook Nuclear Power Station Unit 1, 24 Month Fuel Cycle Evaluation", June, 1998.~~

Methodology for Specification:
2.2.1 - Limiting Safety System Settings
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

8. YAEC-1856P, "System Transient Analysis Methodology Using RETRAN for PWR Applications," December, 1992.

Methodology for Specification:
2.2.1 - Limiting Safety System Settings
3.1.1.3 - Moderator Temperature Coefficient
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

9. YAEC-1752, "STAR Methodology Application for PWRs, Control Rod Ejection, Main Steam Line Break," October, 1990.

Methodology for Specification:
3.1.1.3 - Moderator Temperature Coefficient
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

6.8.1.6.b. (Continued)

10. YAEC-1855PA, "Seabrook Station Unit 1 Fixed Incore Detector System Analysis," October, 1992.

    Methodology for Specification:
    3.2.1 - AXIAL FLUX DIFFERENCE
    3.2.2 - Heat Flux Hot Channel Factor
    3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

11. YAEC-1624P, "Maine Yankee RPS Setpoint Methodology Using Statistical Combination of Uncertainties - Volume 1 - Prevention of Fuel Centerline Melt," March, 1988.

    Methodology for Specification:
    3.2.1 - AXIAL FLUX DIFFERENCE
    3.2.2 - Heat Flux Hot Channel Factor
    3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

12. NYN-95048, Letter from T. C. Feigenbaum (NAESCo) to NRC, ".License Amendment Request 95-05: Positive Moderator Temperature Coefficient", May 30, 1995.

    Methodology for Specification:
    3.1.1.3 - Moderator Temperature Coefficient

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

    Methodology for Specification:
    3.2.2 - Heat Flux Hot Channel Factor

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

    ~~WCAP-8385-P, (Proprietary), "Power Distribution Control and Load Following Procedures", September, 1974.~~

    Methodology for Specification:
    3.2.1 - AXIAL FLUX DIFFERENCE
    3.2.2 - Heat Flux Hot Channel Factor

There is additional margin available to offset any other DNBR penalties and

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR and NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

$F_{\Delta}^{N}{}_{H}$ will be maintained within its limits provided Conditions a. through d. above are maintained. ~~The design limit DNBR includes margin to offset any rod bow penalty.~~ Margin is ~~also~~ maintained between the safety analysis limit DNBR and the design limit DNBR. ~~This margin is available~~ for plant design flexibility.

When an $F_Q(Z)$ measurement is taken, an allowance for both measurement error and manufacturing tolerance must be made. An allowance of 5% is appropriate for a full-core map taken with the movable incore detectors, while 5.21% is appropriate for surveillance results determined with the fixed incore detectors. A 3% allowance is appropriate for manufacturing tolerance.

The hot channel factor $F^{M}{}_{Q}(Z)$ is measured periodically and increased by a cycle and height dependent power factor appropriate to Relaxed Axial Offset Control (RAOC) operation, W(Z), to provide assurance that the limit on the hot channel factor $F_Q(Z)$ is met. W(Z) accounts for the effects of normal operation transients and was determined from expected power control maneuvers over the full range of burnup conditions in the core. The W(Z) function for normal operation is specified in the CORE OPERATING LIMITS REPORT per Specification 6.8.1.6.

When RCS $F_{\Delta}^{N}{}_{H}$ is measured, no additional allowances are necessary prior to comparison with the established limit. ~~A bounding measurement error of 4.13% for $F_{\Delta}^{N}{}_{H}$ has been allowed for in determination of the design DNBR value.~~

3/4.2.4 QUADRANT POWER TILT RATIO

The purpose of this specification is to detect gross changes in core power distribution between monthly Incore Detector System surveillances. During normal operation the QUADRANT POWER TILT RATIO is set equal to 1.0 once acceptability of core peaking factors has been established by review of incore surveillances. The limit of 1.02 is established as an indication that the power distribution has changed enough to warrant further investigation.

Appropriate $F_{\Delta}^{N}{}_{H}$ measurement uncertainties are already incorporated into the $F_{\Delta}^{N}{}_{H}$ limits established in the CORE OPERATING LIMITS REPORT for each measurement system, and a bounding $F_{\Delta}^{N}{}_{H}$ measurement uncertainty has been applied in determination of the design DNBR value. The appropriate $F_{\Delta}^{N}{}_{H}$ measurement uncertainties are 4.13% for the fixed incore detector system and 4% for the movable incore detector system.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary System pressure will be limited to within 110% (1320 psia) of its design pressure of 1200 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a Turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, (1974 Edition, including the Summer 1975 Addenda). The total relieving capacity for all valves on all of the steam lines is 1.816 x 10^7 lbs/hr which is ~~120~~ 109.8% of the total secondary steam flow of ~~1.514~~ 1.654 x 10^7 lbs/hr at 100% RATED THERMAL POWER. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

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

For four loop operations:

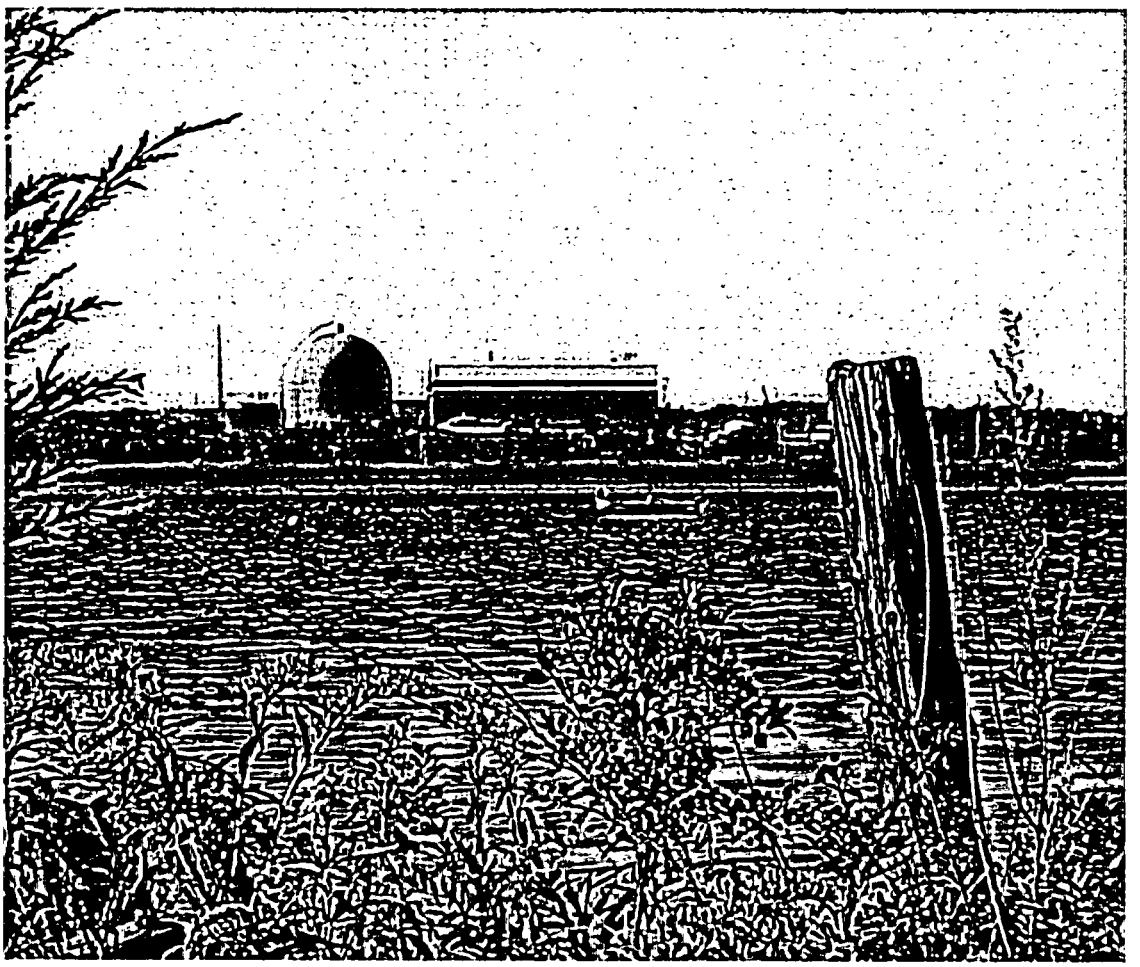
$$HiØ = (100/Q_{rated})X\left[\frac{(W_s \times h_{fg} \times N)}{K} - Q_{rcp}\right]$$

where:

HiØ	=	Safety Analysis power range high neutron flux setpoint, percent of RATED THERMAL POWER
Q_{rated}	=	RATED THERMAL POWER, Mwt
Q_{rcp}	=	Reactor coolant pump heat, Mwt
K	=	Conversion factor, 3.412 x 10^6 (Btu/hr)/Mwt
h_{fg}	=	heat of vaporization for steam at 110% of the Secondary System design pressure, Btu/lbm
N	=	Number of loops in plant
W_s	=	Minimum total steam flow rate, lbm/hr, of the operable MSSVs on any one steam generator at the MSSV inlet pressure which assures all Secondary System pressures are no greater than 110% of design.

Stretch Power Uprate
License Amendment Request

SEABROOK STATION



ATTACHMENT 3

RETYPED FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION PAGES

ATTACHMENT 3
RETYPED PAGES FOR PROPOSED CHANGES TO THE FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATIONS

LIST OF PAGES CONTAINING PROPOSED CHANGES

Page Number	Current Amendment Number
Facility Operating License	
3	95
Technical Specifications	
1-5	81
2-1	
2-5	77
2-8	76
2-10	76
3/4 2-6b	76
3/4 2-10	
3/4 3-26	45
3/4 3-27	60
3/4 7-2	43
6-18B	
6-18C	
6-18D	76
Technical Specification Bases	
B 3/4 2-3	76
B 3/4 7-1	43

The attached retyped pages reflect the currently issued revision of the Facility Operating License NPF-86 and the Seabrook Station Technical Specifications and Bases. Pending changes are not reflected in the attached retyped pages.

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

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

(6) FPL Energy Seabrook, LLC, pursuant to the Act and 10 CFR 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility authorized herein; and

(7) DELETED

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I 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

FPL Energy Seabrook, LLC, is authorized to operate the facility at reactor core power levels not in excess of 3587 megawatts thermal (100% of rated power).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. , and the Environmental Protection Plan contained in Appendix B are incorporated into Facility License No. NPF-86. FPL Energy Seabrook shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) License Transfer to FPL Energy Seabrook, LLC

a. On the closing date(s) of the transfer of any ownership interests in Seabrook Station covered by the Order approving the transfer, FPL Energy Seabrook, LLC, shall obtain from each respective transferring owner all of the accumulated decommissioning trust funds for the facility, and ensure the deposit of such funds and additional funds, if necessary, into a decommissioning trust or trusts for Seabrook Station established by FPL Energy Seabrook, LLC, such that the amount of such funds deposited meets or exceeds the amount required under 10 CFR 50.75 with respect to the interest in Seabrook Station FPL Energy Seabrook, LLC, acquires on such dates(s).

PHYSICS TESTS

1.23 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation: (1) described in Chapter 14.0 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.24 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a nonisolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.

PROCESS CONTROL PROGRAM

1.25 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, tests, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State Regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.26 PURGE or PURGING shall be any controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

QUADRANT POWER TILT RATIO

1.27 QUADRANT POWER TILT RATIO 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. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER

1.28 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3587 Mwt.

REACTOR TRIP SYSTEM (RTS) RESPONSE TIME

1.29 The RTS RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its RTS Trip Setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

2.1 SAFETY LIMITS (SLs)

2.1.1 REACTOR CORE SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR; and the following SLs shall not be exceeded.

2.1.1.1 The departure from nucleate boiling ration (DNBR) shall be maintained greater than or equal to 1.14 for the WRB-2M DNB correlation.

2.1.1.2 The peak fuel centerline temperature shall be maintained less than 5090°F, decreasing by 58°F per 10,000 MWD/MTU of burnup.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained less than or equal to 2735 psig.

2.1.3 SAFETY LIMIT VIOLATIONS:

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

2.1.3.2 If SL 2.1.2 is violated:

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

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

TABLE 2.1-1 (continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
11. Pressurizer Water Level - High	8.0	4.20	0.84	≤92% of instrument span	≤93.75% of instrument span
12. Reactor Coolant Flow – Low	N.A.	N.A.	N.A.	≥90% of indicated loop flow	≥89.6% of indicated loop flow
13. Steam Generator Water Level Low – Low	N.A.	N.A.	N.A.	≥20.0% of narrow range instrument span	≥19.5% of narrow range instrument span
14. Undervoltage – Reactor Coolant Pumps	15.0	1.39	0	≥10,200 volts	≥9,822 volts
15. Underfrequency – Reactor Coolant Pumps	2.9	0	0	≥55.5 Hz	≥55.3 Hz
16. Turbine Trip					
a. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	≥500 psig	≥450 psig
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	≥1% open	≥1% open
17. Safety Injection Input from ESF	N.A.	N.A.	N.A.	N.A.	N.A.

TABLE 2.2-1 (Continued)

TABLE NOTATIONS

NOTE 1: (Continued)

T' Indicated RCS T_{avg} at RATED THERMAL POWER, °F, (Calibration temperature for ΔT instrumentation, value specified in the COLR);

K_3 = Value specified in COLR;

P = Measured Pressurizer pressure, psig;

P' = Nominal RCS operating pressure, psig, value specified in the COLR;

S = Laplace transform operator, s^{-1};

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers as specified in the COLR.

NOTE 2: Cycle dependent values for the channel's Allowable Value are specified in the COLR.

TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6 = Value specified in COLR,

T = As defined in Note 1,

T" = Indicated T_{avg} at RATED THERMAL POWER, °F, (Calibration temperature for ΔT instrumentation, value specified in the COLR),

S = As defined in Note 1, and

$f_2(\Delta I)$ = A function of the indicated difference between the top and bottom detectors of the power-range neutron ion chambers as specified in the COLR.

NOTE 4: Cycle dependent values for the channel's Allowable Value are specified in the COLR.

g. The limits specified in Specification 4.2.2.2.c, 4.2.2.2.e, and 4.2.2.2.f above are not applicable in the following core plane regions:

1) Lower core region from 0 to 10%, inclusive.

2) Upper core region from 90 to 100%, inclusive.

4.2.2.3 When $F_Q(Z)$ is measured for reasons other than meeting the requirements of Specification 4.2.2.2, an overall measured $F_Q(Z)$ shall be obtained from a power distribution map and increased by 3% to account for manufacturing tolerances and further increased by 5% when using the moveable incore detectors or 5.21% when using the fixed incore detectors to account for measurement uncertainty.

4.2.2.4 (THIS SPECIFICATION NUMBER IS NOT USED)

3/4.2.5 DNB PARAMETERS

LIMIITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System T_{avg} is less than or equal to the limit specified in the COLR,

b. Pressurizer Pressure is greater than or equal to the limit specified in the COLR*, and

c. Reactor Coolant System Flow shall be:

1) $\geq$ 374,000 gpm**, and,

2) $\geq$ 383,000 gpm***

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the parameters shown above shall be verified to be within its limits at least once per 12 hours.

4.2.5.2 The RCS flow rate indicators shall be subjected to CHANNEL CALIBRATION at least once per 18 months.

4.2.5.3 The RCS total flow rate shall be determined by an approved method to be within its limit prior to operation above 95% of RATED THERMAL POWER after each fuel loading. The provisions of Specification 4.0.4 are not applicable for entry into MODE 1.

---

* Limit not applicable during either THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% or RATED THERMAL POWER.

** Thermal Design Flow. An allowance for measurement uncertainty shall be made when comparing measured flow to Thermal Design Flow.

*** Minimum measured flow used in the Revised Thermal Design Procedure.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation (System)	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Containment Pressure--Hi-2	5.2	0.71	1.67	≤4.3 psig	≤5.3 psig
d. Steam Line Pressure--Low	13.1	10.71	1.63	≥585 psig	≥568 psig*
e. Steam Generator Pressure - Negative Rate--High	3.0	0.5	0	≤100 psi	≤123 psi**
5. Turbine Trip					
a. Automatic Actuation Logic Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. Steam Generator Water Level—High-High (P-14)	N.A.	N.A.	N.A.	≤90.8% of narrow range instrument span.	≤91.3% of narrow range instrument span.
6. Feedwater Isolation					
a. Steam Generator Water Level--Hi-Hi-(P-14)	N.A.	N.A.	N.A.	≤90.8% of narrow range instrument span.	≤91.3% of narrow range instrument span.
b. Safety Injection	N.A.	N.A.	N.A.	N.A.	N.A.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
7. Emergency Feedwater					
a. Manual Initiation					
(1) Motor driven pump	N.A.	N.A.	N.A.	N.A.	N.A.
(2) Turbine driven pump	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Steam Generator Water Level--Low-Low Start Motor-Driven Pump and Start Turbine-Driven Pump	N.A.	N.A.	N.A.	≤20.0% of narrow range instrument span.	≤19.5% of narrow range instrument span.
d. Safety Injection Start Motor-Driven Pump and Turbine-Driven Pump	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.				
e. Loss-of-Offsite Power Start Motor-Driven Pump and Turbine-Driven Pump	See Item 9. for Loss-of-Offsite Power Setpoints and Allowable Values.				
8. Automatic Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. RWST Level -Low-Low Coincident With Safety Injection	4.0*** 2.1**** See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	1.0	2.8	120.478 gals.	≤121,521*** gals. ≥119,435**** gals.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING FOUR-LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT (PERCENT OF RATED THERMAL POWER)
1	60
2	42
3	25

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER					
Loop 1	Loop 2	Loop 3	Loop 4	LIFT SETTING* (± 3%)**	ORIFICE SIZE
V6	V22	V36	V50	1185 psig	16.0 sq. in.
V7	V23	V37	V51	1195 psig	16.0 sq. in.
V8	V24	V38	V52	1205 psig	16.0 sq. in.
V9	V25	V39	V53	1215 psig	16.0 sq. in.
V10	V26	V40	V54	1225 psig	16.0 sq. in.

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

** Within ±1% following main steam line Code safety valve testing.

6.8.1.6.b. (Continued)

Methodology for Specifications:
3.1.1.1 - SHUTDOWN MARGIN for MODES 1,2, 3, and 4
3.1.1.2 - SHUTDOWN MARGIN for MODE 5
3.1.1.3 - Moderator Temperature Coefficient
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

4. Seabrook Station Updated Final Safety Analysis Report, Section 15.4.6, "Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant System".

Methodology for Specifications:
3.1.1.1 - SHUTDOWN MARGIN for MODES 1, 2, 3, and 4
3.1.1.2 - SHUTDOWN MARGIN for MODE 5

5. YAEC-1241, "Thermal-Hydraulic Analysis of PWR Fuel Elements Using the CHIC-KIN Code", R. E. Helfrich, March, 1981.

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

WCAP-15025-P-A, Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17X17 Rod Bundles with Modified LPD Mixing Vane Grids, April, 1999.

Methodology for Specification:
2.1 Safety Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor
3.2.5 DNB Parameters

6. YAEC-1849P, "Thermal-Hydraulic Analysis Methodology Using VIPRE-01 For PWR Applications," October, 1992.

WCAP-11397-P-A, (Proprietary), "Revised Thermal Design Procedure", April, 1989.

WCAP-8745-P-A, "Design Basis For The Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986.

6.8.1.6.b. (Continued)

Methodology for Specification:
2.2.1 - Limiting Safety System Settings
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

7. YAEC-1854P, "Core Thermal Limit Protection Function Setpoint Methodology For Seabrook Station," October, 1992

Methodology for Specification:
2.2.1 - Limiting Safety System Settings
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

8. YAEC-1856P, "System Transient Analysis Methodology Using RETRAN for PWR Applications," December, 1992.

Methodology for Specification:
2.2.1 - Limiting Safety System Settings
3.1.1.3 - Moderator Temperature Coefficient
3.1.3.5 - Shutdown Rod Insertion Limit
3.1.3.6 - Control Rod Insertion Limits
3.2.1 - AXIAL FLUX DIFFERENCE
3.2.2 - Heat Flux Hot Channel Factor
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Methodology for Specification:
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3.2.1 - AXIAL FLUX DIFFERENCE
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6.8.1.6.b. (Continued)

10. YAEC-1855PA, "Seabrook Station Unit 1 Fixed Incore Detector System Analysis," October, 1992.

    Methodology for Specification:
    3.2.1 - AXIAL FLUX DIFFERENCE
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    Methodology for Specification:
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    3.2.2 - Heat Flux Hot Channel Factor
    3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor

12. NYN-95048, Letter from T. C. Feigenbaum (NAESCo) to NRC, ".License Amendment Request 95-05: Positive Moderator Temperature Coefficient", May 30, 1995.

    Methodology for Specification:
    3.1.1.3 - Moderator Temperature Coefficient

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

    Methodology for Specification:
    3.2.2 - Heat Flux Hot Channel Factor

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

    Methodology for Specification:
    3.2.1 - AXIAL FLUX DIFFERENCE
    3.2.2 - Heat Flux Hot Channel Factor

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR and NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

$F_{\Delta}^{N}{}_{H}$ will be maintained within its limits provided Conditions a. through d. above are maintained. Margin is maintained between the safety analysis limit DNBR and the design limit DNBR. There is additional margin available to offset any other DNBR penalties and for plant design flexibility.

When an $F_Q(Z)$ measurement is taken, an allowance for both measurement error and manufacturing tolerance must be made. An allowance of 5% is appropriate for a full-core map taken with the movable incore detectors, while 5.21% is appropriate for surveillance results determined with the fixed incore detectors. A 3% allowance is appropriate for manufacturing tolerance.

The hot channel factor $F^{M}{}_{Q}(Z)$ is measured periodically and increased by a cycle and height dependent power factor appropriate to Relaxed Axial Offset Control (RAOC) operation, W(Z), to provide assurance that the limit on the hot channel factor $F_Q(Z)$ is met. W(Z) accounts for the effects of normal operation transients and was determined from expected power control maneuvers over the full range of burnup conditions in the core. The W(Z) function for normal operation is specified in the CORE OPERATING LIMITS REPORT per Specification 6.8.1.6.

When RCS $F_{\Delta}^{N}{}_{H}$ is measured, no additional allowances are necessary prior to comparison with the established limit. Appropriate $F_{\Delta}^{N}{}_{H}$ measurement uncertainties are already incorporated into the $F_{\Delta}^{N}{}_{H}$ limits established in the CORE OPERATING LIMITS REPORT for each measurement system, and a bounding $F_{\Delta}^{N}{}_{H}$ measurement uncertainty has been applied in determination of the design DNBR value. The appropriate $F_{\Delta}^{N}{}_{H}$ measurement uncertainties are 4.13% for the fixed incore detector system and 4% for the movable incore detector system.

3/4.2.4 QUADRANT POWER TILT RATIO

The purpose of this specification is to detect gross changes in core power distribution between monthly Incore Detector System surveillances. During normal operation the QUADRANT POWER TILT RATIO is set equal to 1.0 once acceptability of core peaking factors has been established by review of incore surveillances. The limit of 1.02 is established as an indication that the power distribution has changed enough to warrant further investigation.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary System pressure will be limited to within 110% (1320 psia) of its design pressure of 1200 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a Turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, (1974 Edition, including the Summer 1975 Addenda). The total relieving capacity for all valves on all of the steam lines is 1.816×10^7 lbs/hr which is 109.8% of the total secondary steam flow of 1.654×10^7 lbs/hr at 100% RATED THERMAL POWER. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

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

For four loop operations:

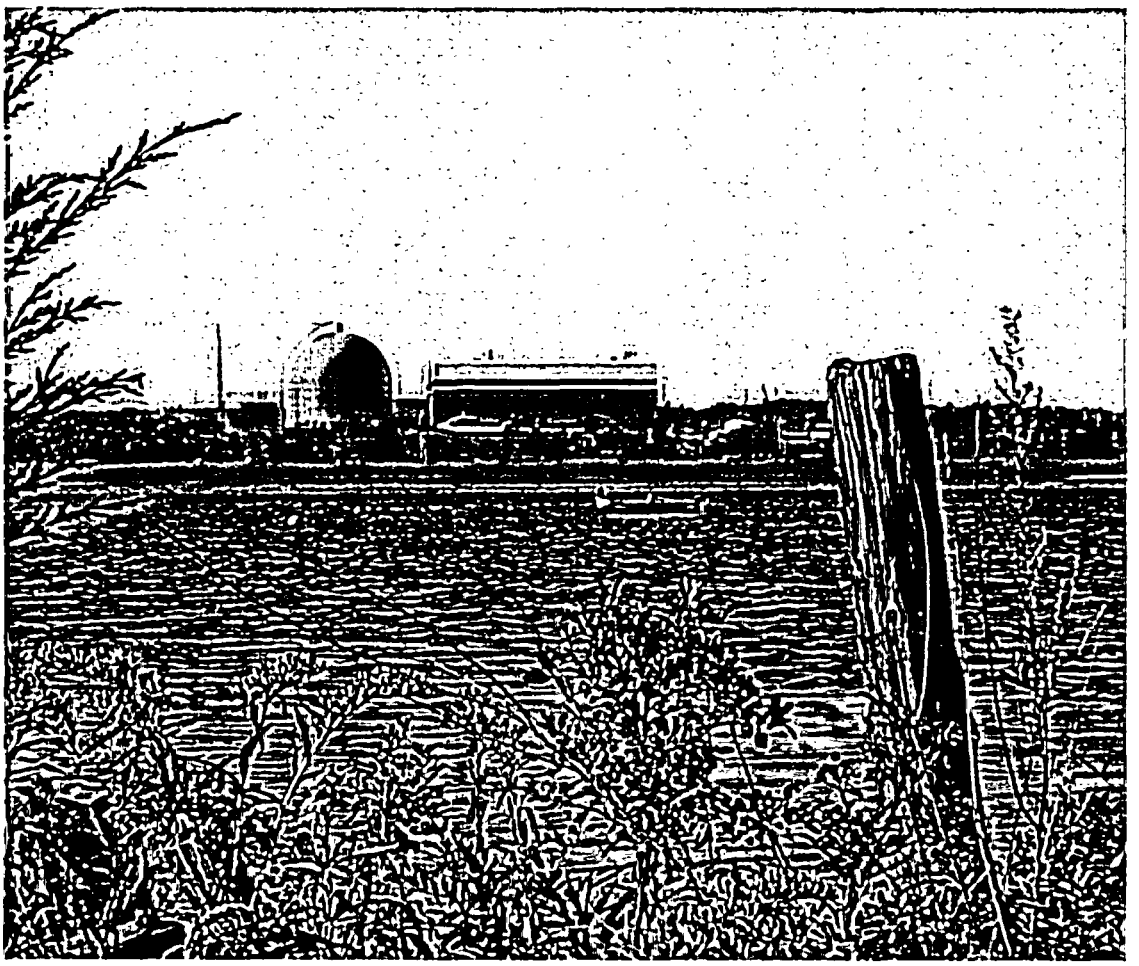
$$HiØ = (100/Q_{rated}) X \left[\frac{(W_s \times h_{fg} \times N)}{K} - Q_{rcp} \right]$$

where:

HiØ	=	Safety Analysis power range high neutron flux setpoint, percent of RATED THERMAL POWER
Q_{rated}	=	RATED THERMAL POWER, Mwt
Q_{rcp}	=	Reactor coolant pump heat, Mwt
K	=	Conversion factor, 3.412×10^6 (Btu/hr)/Mwt
h_{fg}	=	heat of vaporization for steam at 110% of the Secondary System design pressure, Btu/lbm
N	=	Number of loops in plant
W_s	=	Minimum total steam flow rate, lbm/hr, of the operable MSSVs on any one steam generator at the MSSV inlet pressure which assures all Secondary System pressures are no greater than 110% of design.

Stretch Power Uprate
License Amendment Request

SEABROOK STATION



ATTACHMENT 4

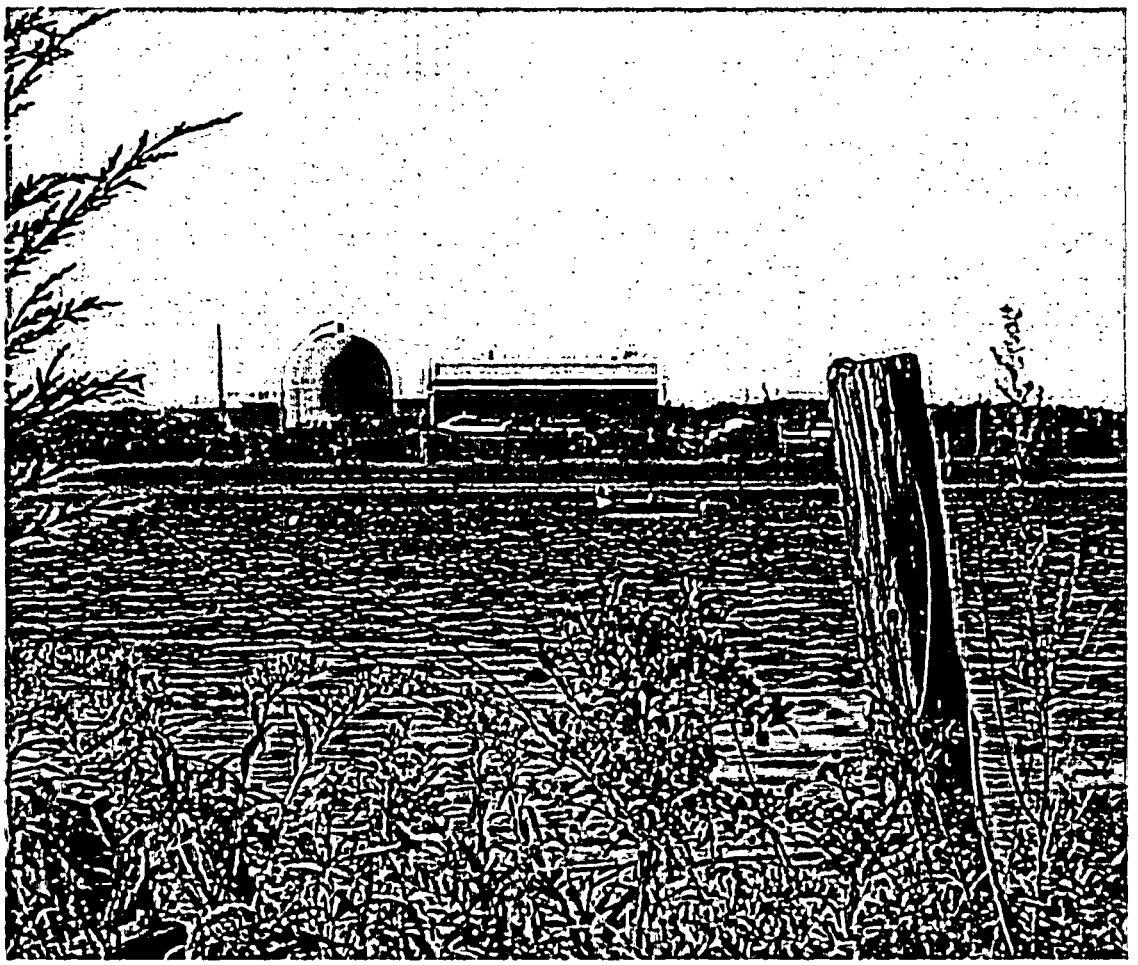
LIST OF REGULATORY COMMITMENTS

ATTACHMENT 4
LIST OF REGULATORY COMMITMENTS

There are no regulatory commitments associated with approval or implementation of this license amendment request.

Stretch Power Uprate
License Amendment Request

SEABROOK STATION



ATTACHMENT 5

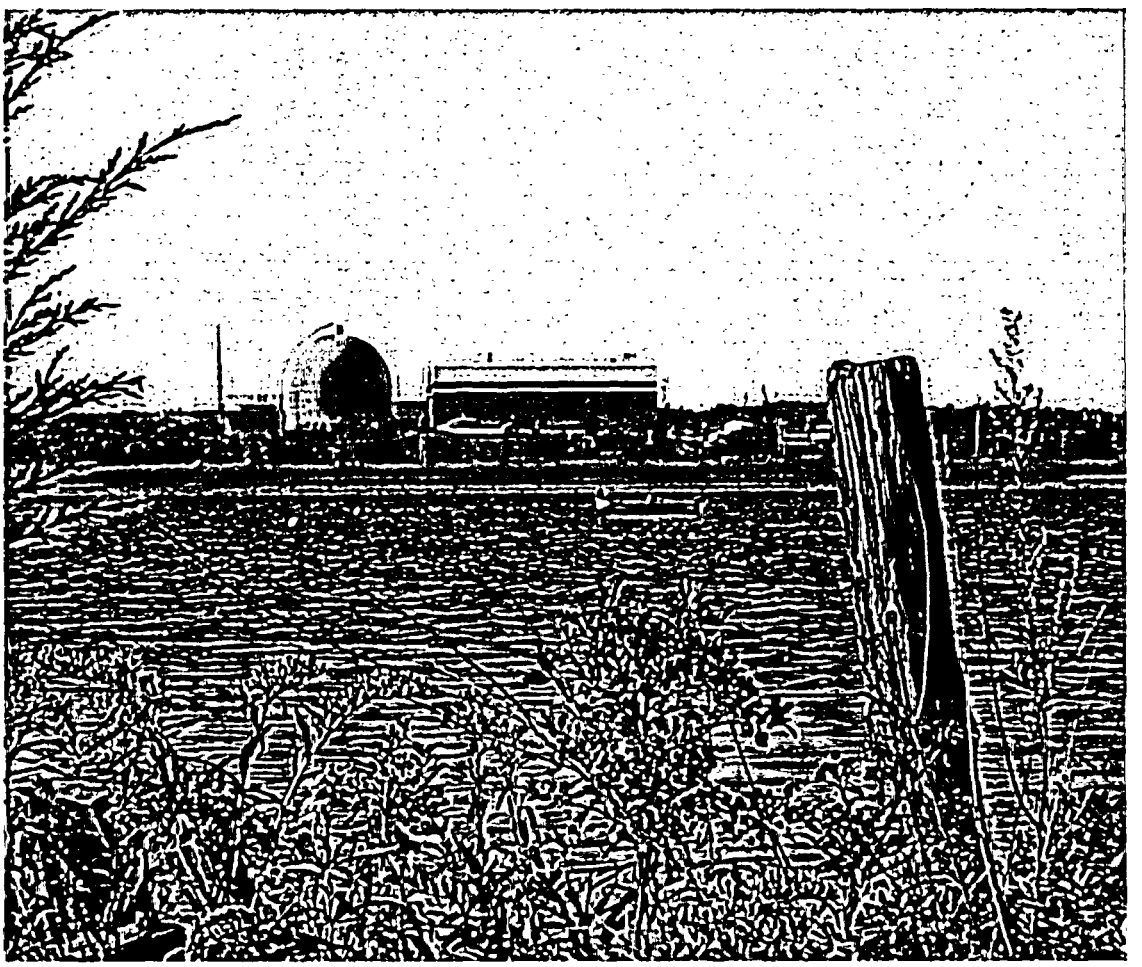
PROPOSED SCHEDULE FOR LICENSE AMENDMENT AND ISSUANCE

ATTACHMENT 5
PROPOSED SCHEDULE FOR LICENSE AMENDMENT AND ISSUANCE

FPLE requests approval of this proposed amendment for licensed thermal power uprate by December 31, 2004 which is consistent with NRC review schedules for stretch power uprates. The requested implementation period is 12 months. Approval by December 31, 2004 would support the refueling outage currently scheduled to begin in April 2005. This date allows Seabrook Station to take advantage of the economic benefits of the power uprate as soon as possible.

Stretch Power Uprate
License Amendment Request

SEABROOK STATION



ATTACHMENT 6

SIGNIFICANT HAZARDS CONSIDERATION

ATTACHMENT 6
NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The proposed license amendments will revise the Seabrook Station Facility Operating License NPF-86 and the Technical Specifications to increase the licensed core thermal power by approximately 5.2% from 3411 MWt to 3587 MWt. The proposed changes are described in detail below and are also indicated on the marked up and retyped pages for the Facility Operating License and Technical Specifications contained in LAR Attachments 2 and 3. The changes to the Facility Operating License and Technical Specifications have been grouped and each group will be evaluated pursuant to the requirements of 10 CFR 50.92. Corresponding Technical Specification Bases changes are being made to reflect the changes to the Technical Specifications. A description of the Technical Specification Bases changes is provided in Section 3.0 of this attachment.

1.0 DESCRIPTION OF LICENSE AND TECHNICAL SPECIFICATION CHANGES INCLUDING NO SIGNIFICANT HAZARDS DETERMINATION

1.1 RATED THERMAL POWER CHANGE

Description Of The Proposed Change

- Facility Operating License NPF-86, paragraph 2.C(1), "Maximum Power Level," has been revised to authorize operation at reactor core power levels not in excess of 3587 MWt.
- Technical Specification 1.0, paragraph 1.28, "Rated Thermal Power," has been revised to increase power from 3411 MWt to 3587 MWt.

Significant Hazards Consideration

The Seabrook Station SPU evaluations discussed in LAR Attachment 1, Section 6.0, Accident Analyses, demonstrated that this increased thermal power still allows safe operation of the plant and will not affect the health and safety of the public. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in power level, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied. Additionally, the proposed change in power level was not found to initiate any accident, and therefore, does not increase the probability of an accident.

   Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in rated thermal power. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in rated thermal power.

1.2 SAFETY LIMITS (SLs) CHANGE

Description Of The Proposed Change

Technical Specification 2.1.1, Reactor Core Safety Limits is revised as follows:

- The departure from nucleate boiling ratio limit is Specification 2.1.1.1 is changed from 1.17 to 1.14 and the WRB-1 and WRB-2 correlations are deleted.

Significant Hazards Consideration

The change in the departure from nucleate boiling ratio limit is necessary to support the WRB-2M correlation. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in the departure from nucleate boiling ratio limit, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in the departure from nucleate boiling ratio limit was not found to initiate any accident, and therefore, does not increase the probability of an accident.

   Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in the

departure from nucleate boiling ratio limit. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in the departure from nucleate boiling ratio limit.

1.3 REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINT CHANGE

Description Of The Proposed Change

Technical Specification Table 2.1-1, Reactor Trip System Instrumentation Trip Setpoints, Functional Unit 13, Steam Generator Water Level Low-Low is revised as follows:

- The Trip Setpoint is changed from ≥14.0% to ≥20.0% of narrow range instrument span.
- The Allowable Value is changed from ≥12.6% to ≥19.5% of narrow range instrument span.
- The Total Allowance (TA), Z, and Sensor Error (S) are changed from values to N.A.

Significant Hazards Consideration

The basis for the increase in the Steam Generator Water Level Low-Low Reactor Trip setpoint is ensuring that the ability to remove long-term decay heat, stored energy, and reactor coolant pump heat, to prevent overpressurization of the Reactor Coolant System, and to prevent reactor core uncovery is maintained . The revised Steam Generator Water Level Low-Low Reactor Trip setpoint is consistent with SPU evaluations as documented by LAR Attachment 1, Section 4.3, NSSS Instrumentation and Controls. These evaluations demonstrated that the increase in the Steam Generator Water Level Low-Low Reactor Trip setpoint will allow safe operation of the plant and will not affect the health and safety of the public. The Total Allowance (TA), Z, and Sensor Error (S) values for the revised Steam Generator Water Low-Low Level Reactor Trip setpoint are listed as NA. This setpoint format is consistent with the Overtemperature ΔT and Overpower ΔT trips and the Low Reactor Coolant System Flow trip. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of

these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in Steam Generator Water Level Low-Low Reactor Trip setpoint, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in Steam Generator Water Level Low-Low Reactor Trip setpoint was not found to initiate any accident, and therefore, does not increase the probability of an accident.

Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in Steam Generator Water Level Low-Low Reactor Trip setpoint. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in Steam Generator Water Level Low-Low Reactor Trip setpoint.

1.4 OVERTEMPERATURE ΔT AND OVERPOWER ΔT ADMINISTRATIVE CHANGE

Description Of The Proposed Change

Technical Specification Table 2.1-1, Notes 1 and 3 are changed to correct typographical errors:

- For Note 1, T^1 is changed to T' and P^1 is change to P'.
- For Note 3, T^{11} is changed to T".

Significant Hazards Consideration

These changes correct typographical errors and are administrative in nature. Therefore, the changes do not affect safe operation of the plant and will not affect the health and safety of the general public. Based on the administrative nature of the

changes, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   These changes are administrative in nature and do not affect the operation of Seabrook Station. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed administrative changes were not found to initiate any accident, and therefore, does not increase the probability of an accident.

   In addition, the proposed administrative changes do not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed administrative changes. The changes have no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed administrative changes. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   These changes are administrative and do not affect the safety analyses. Therefore, the proposed changes do not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with these administrative changes.

1.5 POWER DISTRIBUTION LIMITS - HEAT FLUX HOT CHANNEL FACTOR CHANGE

Description Of The Proposed Change

Technical Specification Surveillance Requirement 4.2.2.2.g is changed as follows:

- Specification 4.2.2.2.g.1) Lower Core Region is changed from 0 to 15%, inclusive to 0 to 10%, inclusive.
- Specification 4.2.2.2.g.1) Upper Core Region is changed from 85 to 100%, inclusive to 90 to 100%, inclusive.

Significant Hazards Consideration

The basis for the reduction in the core plane regions in which the heat flux hot channel factor ($F_Q(Z)$) surveillance requirement is not applicable is to ensure that the

increase in licensed thermal power will not result in exceeding departure from nucleate boiling or core centerline melting design bases. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in heat flux hot channel factor – power distribution limits, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in heat flux hot channel factor – power distribution limits was not found to initiate any accident, and therefore, does not increase the probability of an accident.

   Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in heat flux hot channel factor – power distribution limits. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in reduction in the core plane regions in which the heat flux hot channel factor ($F_Q(Z)$) – power distribution limits.

1.6 POWER DISTRIBUTION LIMINTS - DEPARTURE FROM NUCLEATE BOILING PARAMETERS CHANGE

Description Of Proposed Change

Technical Specification Limiting Condition for Operation 3.2.5 is changed as follows:

- Specification 3.2.5.c.1) Reactor Coolant System Flow is changed from 382,800 gpm to 374,400 gpm.
- Specification 3.2.5.c.2) Reactor Coolant System Flow is changed from 392,800 gpm to 383,800 gpm.

Significant Hazards Consideration

The revised values of these parameters are consistent with the Seabrook Station SPU evaluations discussed in LAR Attachment 1, Section 6.0, Accident Analyses. These evaluations demonstrate that the changes to Reactor Coolant System flow will allow safe operation and will not affect the health and safety of the public. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in Reactor Coolant System flow, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in Reactor Coolant System flow was not found to initiate any accident, and therefore, does not increase the probability of an accident.

   Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in Reactor Coolant System flow. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in Reactor Coolant System flow.

1.7 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM STEAM GENERATOR WATER LEVEL HIGH-HIGH INSTRUMENTATION TRIP SETPOINT CHANGE

Description Of Proposed Change

Technical Specification Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Setpoints, Functional Unit 5b, Turbine Trip, Steam Generator Water Level High-High (P14) is revised as follows:

- The Trip Setpoint is changed from ≥86.8% to ≥90.8% of narrow range instrument span.
- The Allowable Value is changed from ≥87.7% to ≥91.3% of narrow range instrument span.
- The Total Allowance (TA), Z, and Sensor Error (S) are changed from values to N.A.

Technical Specification Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Setpoints, Functional Unit 6a, Feedwater Isolation, Steam Generator Water Level Hi-Hi (P14) is revised as follows:

- The Trip Setpoint is changed from ≥86.8% to ≥90.8% of narrow range instrument span.
- The Allowable Value is changed from ≥87.7% to ≥91.3% of narrow range instrument span.
- The Total Allowance (TA), Z, and Sensor Error (S) are changed from values to N.A.

Significant Hazards Consideration

The basis for the change in the Steam Generator Water Level Engineered Safety Feature Actuation System setpoint is ensuring that the ability to remove long-term decay heat, stored energy, and reactor coolant pump heat, to prevent overpressurization of the Reactor Coolant System, and to prevent reactor core uncovery is maintained . The revised Steam Generator Water Level High-High Engineered Safety Feature Actuation System setpoint is consistent with SPU evaluations as documented by LAR Attachment 1, Section 4.3, NSSS Instrumentation and Controls. These evaluations demonstrated that the increase in the Steam Generator Water Level High-High Engineered Safety Feature Actuation System setpoint will allow safe operation of the plant and will not affect the health and safety of the public. The Total Allowance (TA), Z, and Sensor Error (S) values for the revised Steam Generator Water Level High – High Engineered Safety Feature Actuation System setpoint are listed as NA. This setpoint format is consistent with the Overtemperature ΔT and Overpower ΔT trips and the Low Reactor Coolant System Flow trip. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in Steam Generator Water Level High-High Engineered Safety Feature Actuation System setpoints, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in Steam Generator Water Level High-High Engineered Safety Feature Actuation System setpoints was not found to initiate any accident, and therefore, does not increase the probability of an accident.

   Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in Steam Generator Water Level High-High Engineered Safety Feature Actuation System setpoints. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in Steam Generator Water Level High-High Engineered Safety Feature Actuation System setpoint.

1.8 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM STEAM GENERATOR WATER LEVEL LOW-LOW INSTRUMENTATION TRIP SETPOINT CHANGE

Description Of Proposed Change

Technical Specification Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Setpoints, Functional Unit 7c, Emergency Feedwater, Steam

Generator Water Level Low-Low, Start Motor-Driven Pump and Start Turbine-Driven Pump is revised as follows:

- The Trip Setpoint is changed from ≥14.0% to ≥20.0% of narrow range instrument span.
- The Allowable Value is changed from ≥12.6% to ≥19.5% of narrow range instrument span.
- The Total Allowance (TA), Z, and Sensor Error (S) are changed from values to N.A.

Significant Hazards Consideration

The basis for the change in the Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoint is ensuring that the ability to remove long-term decay heat, stored energy, and reactor coolant pump heat, to prevent overpressurization of the Reactor Coolant System, and to prevent reactor core uncovery is maintained . The revised Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoint is consistent with SPU evaluations as documented by LAR Attachment 1, Section 4.3, NSSS Instrumentation and Controls. These evaluations demonstrated that the increase in the Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoint will allow safe operation of the plant and will not affect the health and safety of the public. The Total Allowance (TA), Z, and Sensor Error (S) values for the revised Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoint are listed as NA. This setpoint format is consistent with the Overtemperature ΔT and Overpower ΔT trips and the Low Reactor Coolant System Flow trip. Based on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoints, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoints was not found to initiate any accident, and therefore, does not increase the probability of an accident.

Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoints. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in Steam Generator Water Level Low-Low Engineered Safety Feature Actuation System setpoint.

1.9 PLANT SYSTEMS – TURBINE CYCLE – SAFETY VALVES CHANGE

Description Of Proposed Change

Technical Specification Table 3.7-1, Maximum Allowable Power Range Neutron Flux High Setpoint With Inoperable Steam Line Safety Valves During Four-Loop Operation is revised to indicate the percent of Rated Thermal Power allowed with inoperable safety valves as follows:

- With one inoperable safety valve on any operating steam generator, the percent of rated thermal power is changed from 66 to 60.
- With two inoperable safety valves on any operating steam generator, the percent of rated thermal power is changed from 47 to 42.
- With one inoperable safety valve on any operating steam generator, the percent of rated thermal power is changed from 28 to 25.

Significant Hazards Consideration

The Seabrook Station SPU evaluations discussed in LAR Attachment 1, Section 6.0, Accident Analyses, demonstrated that the reduction in maximum power allowed with inoperable main steam safety valves provides overpressure protection for the Main Steam System at the increased rated thermal power. This will support safe operation of the plant and will not affect the health and safety of the public. Based

on the evaluations of the SPU conditions, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   The Seabrook Station SPU evaluations performed included performance of accident analyses at SPU conditions using approved methodologies. Results of these analyses continue to satisfy the event acceptance criteria. An evaluation of the components and systems, including interface and control systems, that could be affected by the change in the maximum power with safety valves inoperable, was performed for the SPU. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed change in maximum power with safety valves inoperable was not found to initiate any accident, and therefore, does not increase the probability of an accident.

   Dose consequences were evaluated using SPU parameters. Acceptance criteria continued to be satisfied. Therefore, the proposed change does not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. The change has no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change in maximum power with safety valves inoperable. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   The analyses supporting the proposed SPU condition continue to satisfy the appropriate acceptance criteria. Therefore, the proposed change does not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with the change in maximum power with safety valves inoperable.

1.10 ADMINISTRATIVE CONTROLS CHANGES

Description Of The Proposed Change

Technical Specification 6.8.1.6.b.5 is revised as follows:

- WCAP-14565-P is change to WCAP-14565-P-A and the issue date is changed from April,1997 to October 1999.
- The paragraph beginning Letter from T. H. Essig (NRC) is deleted in its entirety.

- WCAP-15025-P is change to WCAP-15025-P-A and the issue date is changed from February,1998 to April, 1999.

Technical Specification 6.8.1.6.b.6 is revised as follows:

- The following paragraph is added, "WCAP-8745-P-A, "Design Basis for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September, 1986."

Technical Specification 6.8.1.6.b.7 is revised as follows:

- The paragraph beginning WCAP-14551-P, is deleted in its entirety.

Technical Specification 6.8.1.6.b.14 is revised as follows:

- The paragraph beginning WCAP-8385-P, is deleted in its entirety.

Significant Hazards Consideration

These changes update the references associated with the Core Operating Limits Report and are administrative in nature. Therefore, the changes do not affect safe operation of the plant and will not affect the health and safety of the general public. Based on the administrative nature of the changes, the following conclusions can be reached with respect to 10 CFR 50.92. The proposed changes will not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.

   These changes are administrative in nature and do not affect the operation of Seabrook Station. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. Additionally, the proposed administrative changes were not found to initiate any accident, and therefore, does not increase the probability of an accident.

   In addition, the proposed administrative changes do not increase the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed administrative changes. The changes have no adverse affect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed administrative changes. Therefore, the possibility of a new or different kind of accident is not created.

3. Involve a significant reduction in a margin to safety

   These changes are administrative and do not affect the safety analyses. Therefore, the proposed changes do not involve a significant reduction in a margin to safety.

Therefore, there are no significant hazards associated with these administrative changes.

2.0 SIGNIFICANT HAZARDS DETERMINATION CONCLUSION

In accordance with the requirements of 10 CFR 50.90, FPL Energy Seabrook hereby requests an amendment to the Facility Operating License NPF-86, for Seabrook Station. The purpose of the proposed LAR is to revise the Facility Operating License and the Technical Specifications to allow operation at an increased licensed core thermal power of 3587 MWt.

FPL Energy Seabrook has evaluated the proposed LAR in accordance with 10 CFR 50.91 against the standards in 10 CFR 50.92 and has determined that the operation of the Seabrook Station in accordance with the proposed LAR presents no significant hazards.

A comprehensive review of accident analyses, component and system analyses, and radiological dose consequences was performed for the SPU. Analyses met the appropriate criteria, as explained in the no significant hazards determinations. Therefore, operation of the Seabrook Station in accordance with the proposed amendments will not result in a significant increase in the probability or consequences of any accident previously analyzed; will not result in a new or different kind of accident from any accident previously analyzed; and will not result in a significant reduction in a margin of safety. Therefore, operation of the Seabrook Station in accordance with the proposed amendments does not involve a significant hazards consideration.

3.0 TECHNICAL SPECIFICATION BASES CHANGES

3.1 TECHNICAL SPECIFCIATION BASES 3/4.2.2 AND 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

The first paragraph on page B 3/4 2-3 is revised to delete the second sentence, delete the word "also" from the third sentence and replace the last sentence with the following sentence, "There is additional margin available to offset any other DNBR penalties and for plant design flexibility."

The last paragraph in this section is revised to replace the last sentence with the following, "Appropriate $F_{\Delta}{}^{N}{}_{H}$ measurement uncertainties are already incorporated into the $F_{\Delta}{}^{N}{}_{H}$ limits established in the CORE OPERATING LIMITS REPORT for each measurement system, and a bounding $F_{\Delta}{}^{N}{}_{H}$ measurement uncertainty has been applied in determination of the design DNBR value. The appropriate $F_{\Delta}{}^{N}{}_{H}$ measurement uncertainties are 4.13% for the fixed incore detector system and 4% for the movable incore detector system."

3.2 TECHNICAL SPECIFICATION BASES 3/4.7.1.1 SAFETY VALVES

In the second paragraph, the total relieving capacity is changed from 120% to 109.8% and the total secondary steam flow is changed from 1.514×10^{7} to 1.654×10^{7}.