YAEC-1871

SAFETY ANALYSIS IN SUPPORT
OF
WIDE-BAND OPERATION
AND
CORE DESIGN ENHANCEMENTS
FOR
SEABROOK STATION

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ABSTRACT

This report provides a Seabrook Station safety analysis for supporting 1) operation with an expanded axial flux difference Limiting Condition for Operation band, and 2) enhanced core and system design features. These benefits are obtained for Seabrook Station through 1) use of the information available from the Fixed Incore Detector System to continuously monitor core performance, 2) implementation of improved fuel design features, and 3) application of Yankee and Westinghouse safety analysis methodologies consistent with methods previously reviewed and approved by the Nuclear Regulatory Commission.

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1.0 INTRODUCTION

This report provides a safety analysis for Seabrook Station in support of operation with an expanded axial flux difference Limiting Condition for Operation (LCO) band and enhanced core and system design features. These benefits are obtained for Seabrook Station through 1) use of the information available from the Fixed Incore Detector System (FIDS) to continuously monitor core performance, 2) implementation of improved fuel design features, and 3) application of improved core safety analysis methodologies applied on Maine Yankee, Yankee Rowe, and other Westinghouse plants which have been previously reviewed and approved by the Nuclear Regulatory Commission (NRC). The programs to expand the axial flux difference LCO and enhance core design parameters have been referred to as the Wide-Band and Fuel Procurement Programs, respectively.

Justification for the expanded axial flux difference LCO band and the enhanced design core parameters is provided through a complete re-analysis of the Seabrook Station Updated Final Safety Analysis Report[1] (UFSAR) Chapter 15 Accident and Transients. The large and small break LOCA analysis was performed by Westinghouse. The remaining Accidents and Transients of the UFSAR Chapter 15 were evaluated by Yankee Atomic Electric Company (Yankee).

Section 2 of this report provides a summary of the analytical methods and application used in re-analyzing the UFSAR Chapter 15 Accidents and Transients for Seabrook Station. As indicated above, the methods applied are consistent with NRC approved methods currently used by Yankee to support reload analysis on Maine Yankee and, in the past, Yankee Rowe. Small differences in the methods have been implemented to accommodate Seabrook plant specific design features. The methods used to support the LOCA analysis include the Westinghouse BART/BASH[24] methodology for large break and the NOTRUMP[25] methodology for small break. These methods have been previously approved by the NRC as applied to other Westinghouse plants similar to Seabrook Station.

Section 3 provides a summary of the enhanced core design parameters and assumptions used in the re-analysis. Emphasis is placed on the changes in inputs and assumptions as compared to the current set of inputs and assumptions that are included in Seabrook Station's design basis. The revised inputs, assumptions, and results of the re-analysis are implemented through changes in the plant Technical Specifications and the Core Operating Limits Report (COLR).

Section 4 discusses the impact of the new analysis input parameters and assumptions on the core thermal and hydraulic design of Seabrook Station.

The accident analysis is presented in Section 5. It includes an evaluation of all postulated events shown in Chapter 15 of the Seabrook Station UFSAR. For those postulated events which are unaffected by the changes, a brief justification is provided. Analysis was performed for affected events using the above methodologies and the results are provided in a format similar to the UFSAR as an aid for review. Proposed changes to the Seabrook Station Technical Specifications for implementing the benefits of the new analysis are provided in a separate document. This report provides justification for the proposed changes.

Results of the thermal-hydraulic and accident analyses documented in Section 4 and 5 demonstrate that Seabrook Station can be safely operated within limits specified in plant Technical Specifications and the COLR.

2.0 ANALYSIS METHODOLOGY AND APPLICATION

This Section provides a summary of the analysis methodologies used in this report and a discussion of the effects of their implementation on the operation of Seabrook Station. As described in Section 1, Westinghouse has performed both the Large and Small Break LOCA analysis and Yankee has performed the evaluation of the remaining Accidents and Transients in the UFSAR. The results of the LOCA analysis are provided in a separate report. The analytical methods used in the analysis presented in this report are consistent with NRC approved methods applied on Maine Yankee, Yankee Rowe, and other Westinghouse plants. Minor changes to the approved methods currently used by Yankee to support core reloads have been implemented to accommodate Seabrook plant specific design features, and are described herein.

The methods applied in this report are listed as follows:

1. YAEC-1849P, "Thermal-Hydraulic Analysis Methodology Using VIPRE-01 For PWR Applications", October 1992.

2. YAEC-1856P, "System Transient Analysis Methodology Using RETRAN For PWR Applications", December 1992.

3. YAEC-1854P, "Core Thermal Limit Protection Function Setpoint Methodology for Seabrook Station", October 1992.

4. YAEC-1752A, "STAR Methodology Application for PWRs, Control Rod Ejection, Main Steam Line Break", Volumes 1 and 2, September/October 1990.

5. YAEC-1659-A, "SIMULATE-3 Validation and Verification", September 1988.

6. Letter, L. A. Tremblay (VYPNC) to USNRC, "FROSSTEY-2 Fuel Performance Code - Vermont Yankee Response to Remaining Concerns," BVY 92-54, dated May 15, 1992

7. YAEC-1241, "Thermal-Hydraulic Analysis of PWR Full Elements Using the CHIC-KIN Code," R. E. Helfrich, March 1981.

Items 4 through 7 above have been previously approved by the NRC. Items 1 through 3 were submitted for NRC review in conjunction with the Seabrook Station Fuel Procurement

and Wide-Band Programs[11]. These three reports describe Yankee analytical methods as applied to Seabrook Station. They include Yankee's thermal-hydraulic subchannel analysis methods using VIPRE-01, system transient analysis methods using RETRAN[8,9], and core thermal limit protection function setpoint methods. These methods are consistent with NRC approved methods applied on Maine Yankee and Yankee Rowe. Small changes in the approved methods currently used by Yankee were necessary to accommodate Seabrook plant specific design features. The specific design features of Seabrook for which the methods were tailored include:

1) automatic rod motion; and,

2) the form of the thermal limit protection functions.

Yankee has been performing thermal-hydraulic subchannel analysis calculations with an NRC approved methodology[36,37] since the early 1970's based on the COBRA IIIc computer code. Yankee has upgraded the approved subchannel analysis method by substituting the VIPRE-01 code for COBRA IIIc. Yankee methods for performing thermal hydraulic subchannel analysis for assessing core Departure from Nucleate Boiling (DNB) performance, in support of Seabrook Station, is provided in YAEC-1849P[4]. The geometric modeling techniques and correlations used with VIPRE-01 are the same as those previously applied in the approved COBRA IIIc method. For identical cases, the differences in results obtained from the VIPRE-01 and COBRA IIIc codes are negligible. The VIPRE-01 computer code has been generically approved by the NRC for application in PWR subchannel analysis. The application of the VIPRE-01 code is restricted by the limitations set forth in the Staff's Safety Evaluation Report. Yankee has followed these restrictions in its application of VIPRE-01. In addition, Yankee has implemented the WRB-1 DNB correlation[5] in VIPRE-01 for analysis for Seabrook Station. This application represents an extension of the previously approved Yankee subchannel analysis methods. Justification of this application is provided in Reference 4 by comparison to Westinghouse DNB data and the development of a statistical DNBR limit.

Yankee has applied the RETRAN and GEMINI computer codes to simulate the system transient behavior for a range of events on both PWR and BWR systems. These analyses and analysis methods have been previously approved by the NRC for specific applications on Yankee Rowe, Maine Yankee, Vermont Yankee, and the Seabrook Station facilities. Both codes have received generic approval by the NRC for application to non-LOCA events. YAEC-1856P[9] documents the extension of Yankee's approved applications for analysis of PWR systems to include the full range of non-LOCA events considered in Chapter 15 of the UFSAR

for which RETRAN has been approved. The extension results in the application of RETRAN to transients for which the approved GEMINI had been previously applied. The application of RETRAN to these events provides the flexibility to accurately model the interaction of control systems; such as, the rod control system, required for performing analysis for a plant of the design of Seabrook Station. RETRAN has been applied to support the analysis results provided in Section 5 of this report.

The support of core thermal limit protection functions at Seabrook Station (e.g. Overpower ΔT and Overtemperature ΔT trip setpoints and axial flux difference ΔI LCO band) is performed using the method described in YAEC-1854P[7]. This methodology is an extension of the NRC approved methodology Yankee applies to determine core thermal limit protection system function setpoints for Maine Yankee. The protection functions for Seabrook and Maine Yankee are very similar, allowing the application of the Maine Yankee method directly to Seabrook. Minor modifications were made to the Maine Yankee approach to accommodate design differences between the plants as described in detail in YAEC-1856P[7]. In both cases, the methodology includes consideration of the use of a Fixed Incore Detector System [2] to continuously monitor compliance of the core power distribution with Technical Specification limits imposed by the Loss of Coolant Accident (LOCA) analysis assumptions. Compliance with LOCA limits is currently assured at Seabrook by operation within a rather tight axial flux difference control band known as Constant Axial Offset Control (CAOC). In the CAOC monitoring scheme, the excore detector axial flux difference indications are used to infer worst case core power distributions. Core operation is limited to an axial flux difference envelope based on worst case power distributions pre-determined by conservative off-line reactor physics analysis.

The use of the Fixed Incore Detector System eliminates much of the uncertainty in quantifying available margin to the LOCA limits associated with off-line inference of worst case power distributions from the excore signals. This allows the axial flux difference LCO band to be expanded beyond that specified by the CAOC philosophy. The axial flux difference LCO band becomes defined by power distribution restraints required to assure adequate initial margin to fuel thermal design limits on DNB and fuel centerline melt for anticipated transients. The methods of determining the axial flux difference LCO band and protection system setpoints for the Overpower ΔT and Overtemperature ΔT trips are described in detail in YAEC-1854P[7]. This portion of the Seabrook analysis effort has been referred to as the Wide-Band program.

3.0 SAFETY ANALYSIS INPUT PARAMETERS AND ASSUMPTIONS

The Fuel Procurement Program and the Wide-Band Program for Seabrook Station include modifications to several safety analysis input parameters and assumptions. These are:

1) Incorporation of the WRB-1 DNB Correlation and Revised Thermal Design Procedure;

2) Increase in the core power distribution peaking factors;

3) Allowance for positive moderator temperature coefficient;

4) Allowance for thimble plug deletion;

5) Allowance for increase in steam generator tube plugging;

6) Flexibility to implement certain new fuel design features in the future, e.g., low pressure drop Zircaloy grids, Zirlo cladding, etc.;

7) Modifications of analysis assumptions related to certain surveillance parameters, e.g., low pressurizer pressure safety injection actuation setpoint and time delay, etc.; and,

8) Expansion of the axial flux difference (ΔI) Limiting Condition for Operation (LCO) band.

This Section provides a discussion of the modified input parameters and assumptions relative to the current licensing analysis for Seabrook Station. The relationships between the new safety analysis input parameters and assumptions and affected portions of the Seabrook Station Technical Specifications are also discussed.

3.1 WRB-1 DNB Correlation and Revised Thermal Design Procedure

The VIPRE-01 computer code[3] using the WRB-1[5] DNB correlation and using the Revised Thermal Design Procedure[6] (RTDP) developed by Westinghouse have been implemented into the Yankee thermal-hydraulic analysis methodology[4]. This yields some minor changes to the cycle independent thermal limit lines in Technical Specification Figure

2.1-1 and to the cycle dependent Overpower ΔT and Overtemperature ΔT trip setpoint parameters and function modifiers in Technical Specification Table 2.2-1. These minor changes are implemented through changes to the Technical Specifications and the Core Operating Limits Report. The WRB-1 and RTDP methodologies have been applied in the revised safety analysis to evaluate fuel DNB performance. Additional discussion of the application of Yankee thermal hydraulic analysis methodology to Seabrook Station is provided in Sections 4 and 5.

3.2 Core Design Power Distribution Peaking Factors

The core design power distribution peaking factors are increased to allow greater flexibility in cycle design. The greater flexibility in cycle design can be used to reduce the number of fresh fuel assemblies loaded in each cycle and, thus, to reduce the number of spent fuel assemblies discharged to the spent fuel pit. The design heat flux hot channel factor, F_Q, is increased from 2.32 to 2.50. The design enthalpy rise hot channel factor at rated thermal power, $F^{RTP}_{\Delta H}$, is increased from 1.55 to 1.65. The power factor multiplier, $PF_{\Delta H}$, used to allow for an increase in the enthalpy rise hot channel factor, $F^N_{\Delta H}$, at reduced power in the expression:

$$F^N_{\Delta H} = F^{RTP}_{\Delta H}\,[1.0 + PF_{\Delta H}\,(1\text{-}P)]$$

where P = the fraction of rated thermal power, and $PF_{\Delta H}$ is increased from 0.2 to 0.3. These parameters are used in the LOCA, fuel performance analysis, and to derive the cycle independent thermal limit lines in Technical Specification Figure 2.1-1. The Overpower ΔT and Overtemperature ΔT trip setpoint function modifiers, $F_1(\Delta I)$ and $F_2(\Delta I)$ in Technical Specification Table 2.2-1, and the axial flux difference LCO band are generated using cycle dependent power distributions. The safety analysis in this report supports these changes which are specified in the COLR.

3.3 Minimum Measured RCS Flow

Yankee's DNB analysis methodology[4] for Seabrook Station includes the Revised Thermal Design Procedure[6] (RTDP) developed by Westinghouse. Using RTDP, a best estimate RCS flow and measurement uncertainty are considered in the derivation of the DNB limit value. The best estimate RCS flow is used in place of the Thermal Design Flow (TDF) in the analysis of DNB related events. Thermal design flow continues to be used in the analysis of all other events outside the applicability of RTDP.

The surveillance of RCS flow is implemented through a revised Technical Specification 3.2.5 requirement that the minimum measured flow is greater than or equal to either of the following:

1) the TDF plus an allowance for measurement uncertainty; and,

2) the flow used in place of the TDF in the analysis of DNB related events when RTDP is used.

3.4 Positive Moderator Temperature Coefficient

Postulated accidents involving a transient heatup of the RCS were reanalyzed assuming a bounding Positive Moderator Temperature Coefficient (PMTC). The coefficient value in the analysis includes a bounding allowance for measurement uncertainty. The use of a PMTC in the safety analysis permits greater flexibility in core design with the same benefits discussed earlier. PMTC is implemented through a revised Technical Specification 3.1.1.3 requirement that the most positive measured moderator temperature coefficient be limited to $+0.5 \times 10^{-4}$ $\Delta k/k/°F$ for power levels up to 70% rated thermal power with a linear ramp to 0 $\Delta k/k/°F$ at 100% rated thermal power, not including uncertainties. This is consistent with current industry practice.

3.5 Steam Generator Tube Plugging

The LOCA and Non-LOCA safety analysis results provided in Section 5 includes an allowance for up to 8% steam generator tube plugging at Seabrook Station. This allowance is implemented by imposing 8% reduction in the steam generator tube heat transfer surface area and 2% reduction in:

1) the best estimate RCS flow used in the analysis of DNB related events; and,

2) the TDF used in the analysis of other events.

The minimum measured flow used in RTDP and specified in Technical Specification 3.2.5, DNB Parameters, includes the 2% reduction. A 2% reduction in the TDF limit is maintained as conservatism in the revised safety analysis to be implemented in the future as needed.

3.6 Core Bypass Flow Rate

The revised LOCA and non-LOCA safety analysis results provided in Section 5 include a change in the fraction of RCS flow which is assumed to bypass the core and be unavailable for heat removal from the fuel rods. This assumption accommodates the possibility of fuel assembly thimble plug deletion in a future cycle. The elimination of thimble plug handling during a refueling outage has the benefit of reducing personnel exposure to radiation and reducing refueling outage time. The design core bypass flow fraction was increased from 5.8% to 7.5%. The core bypass flow fraction actually used in the analysis of DNB related events conservatively bounds the calculated best estimate value of 6.2%.

3.7 Control Rod Drop Time

Low pressure drop Zircaloy fuel assembly grids are under consideration for implementation in a future cycle. This grid design is hydraulically compatible with the current Inconel grid design such that there is no impact on the thermal-hydraulic performance of a transition core with a combination of assemblies containing both types of grids. The new grid design provides an improvement in fuel cycle economics. A small increase in control rod drop time is expected due to a slight reduction in the control rod guide tube inside diameter required to accommodate the new grid. The potential increase in control rod drop time has been incorporated in the revised safety analysis presented in Section 5. The current RCCA drop time to dashpot entry Technical Specification limit of 2.2 seconds is increased to 2.4 seconds to bound the new grid design.

3.8 Uncertainty on Pressurizer Pressure

The assumed uncertainty on pressurizer pressure has been increased from ±30 psi to ±50 psi. This change is reflected in Technical Specification 3.2.5, DNB Parameters.

3.9 Low Pressurizer Pressure Safety Injection Setpoint and Time Delay

The analysis values of the low pressurizer pressure safety injection actuation setpoint and actuation delay (offsite power unavailable) has been changed from 1760 psia and 27 seconds to 1665 psia and 30 seconds. These assumptions have been used in the Section 5 analysis of events when safety injection actuation is predicted to occur. The revised LOCA analysis reported separately also includes these assumptions. This affects Technical Specification Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Setpoints.

3.10 Emergency Core Cooling System Performance Curves

The analysis values for Emergency Core Cooling System pumped injection performance characteristics have been revised to more accurately represent the specific Seabrook system. The revised injection curves have been incorporated in both the analysis in Section 5 and the revised LOCA analysis[12]. The revised curves affect Technical Specification 4.5.2, ECCS Subsystems Surveillance Requirements.

3.11 Emergency Feedwater Temperature and Actuation Time Delay

The assumed Emergency Feedwater (EFW) temperature has been increased from 88°F to 100°F to be consistent with the design limit for the EFW pumps. The EFW System actuation time delay has been increased from 60 seconds to 75 seconds. These revised values have been used in the revised safety analyses presented in Section 5.

3.12 Improved Fuel Cladding Alloy

The revised LOCA analysis reported in Reference 12 has been performed assuming the swelling/burst characteristics of Zirlo fuel cladding alloy. The LOCA analysis is bounding for both Zircaloy and Zirlo fuel cladding. This permits the flexibility of implementing Zirlo cladding in a future cycle. Technical Specification 5.3.1, Reactor Core Fuel Assemblies, is revised to permit this flexibility.

3.13 Turbine Trip on High Steam Generator Water Level

In the analysis of the excess feedwater flow event in Section 5, credit continues to be assumed for turbine trip and main feedwater isolation on High Steam Generator Water Level. The analysis value for the setpoint is relaxed from 90% to 94% narrow range level. This change in the analysis setpoint is maintained as conservatism in the revised safety analysis to be implemented in the future as needed.

3.14 Wide-Band ΔI Operation

The Technical Specification which defines the LCO on axial flux difference, ΔI (T.S. 3.2.1) is modified to implement the benefit of the incore information from the FIDS. The Constant Axial Offset Control (CAOC) requirements are removed from the specification and replaced with a ΔI LCO band defined by the limits of DNB and fuel centerline melt using the Yankee methods described in Reference 7. The LOCA limit on linear heat generation

rate is monitored with the FIDS. An alternate ΔI band is defined when the FIDS are not available. All limits are implemented on a cycle specific basis through the COLR.

4.0 THERMAL AND HYDRAULIC DESIGN

This section provides an evaluation of the impact of the new analysis input parameters and assumptions discussed in Section 3 on the steady state thermal and hydraulic design of Seabrook Station. Revised steady state thermal-hydraulic performance parameters are summarized in Table 4-1 and compared to the current UFSAR parameters. This revised design is used as the basis for core thermal-hydraulic performance evaluations during transient events as discussed in Section 5.

The new analysis input parameters and assumptions which affect steady state thermal-hydraulic design are:

1. Incorporation of the WRB-1 DNB correlation and revised Thermal Design Procedure;

2. Increase in the core design power distribution peaking factors;

3. Allowance for thimble plug deletion;

4. Allowance for increase in steam generator tube plugging;

5. Increased uncertainty on pressurizer pressure; and,

6. Expansion of the axial flux difference (ΔI) limiting condition for operation band.

Each of these new input parameters and assumptions and their impact on Technical Specification and the Core Operating Limits Report (COLR) is separately discussed in Section 3. The cumulative effect of implementing these changes on the thermal-hydraulic design is shown in Table 4-1.

The thermal-hydraulic parameters shown in Table 4-1 were calculated using the methods described below.

DNBR values are determined by Yankee using the VIPRE code[3] and core modeling techniques described in Reference 4.

In addition to presenting the DNBR values for the reference design core power distribution, i.e., 1.55 chopped cosine axial power shape with $F_{\Delta H}$ = 1.65, values are

presented for a limiting power distribution at the edge of the allowable axial flux difference (ΔI) operating band illustrated in Section 5. The method of analysis of allowable normal operating power distributions is discussed in YAEC-1854P[7].

YAEC has benchmarked[4] the WRB-1 DNB correlation[5,13,14] against empirical data using the VIPRE code and RTDP[6]. The resulting WRB-1 correlation limit values and design limit values are also shown in Table 4-1. DNBR safety analysis limit values used to demonstrate acceptable core thermal-hydraulic performance during transients are also shown in the table.

Limits on fuel cladding and pellet thermal performance parameters shown in Table 4-1 have been determined using the FROSSTEY-2 code[15] and the methodologies in References 10 and 15. FROSSTEY-2 was approved for BWR and PWR use in Reference 16.

The revised steady state thermal-hydraulic design maintains sufficient thermal performance margin to permit demonstrating in Section 5 that acceptance criteria for ANS Condition I events (normal operation and operational transients) and ANS Condition II events (faults of moderate frequency) are met.

TABLE 4-1
(Sheet 1 of 2)

THERMAL AND HYDRAULIC EVALUATION TABLE

Design Parameters	Seabrook UFSAR	Seabrook Revised
Reactor core heat output (MWt)	3411	3411
Reactor core heat output (10^6 Btu/hr)	11,641	11,641
Heat generated in fuel (%)	97.4	97.4
System pressure, nominal (psia)	2250	2250
System pressure, minimum steady state (psia)	2220	2200
DNB Correlation	"R" (W-3 with Modified Spacer Factor)	WRB-1[a]
Correlation Limit Value	1.3	1.17[a]
Design Limit Value		
Typical flow channel	1.3	1.26[a]
Thimble (cold wall) flow channel	1.3	1.24[a]
Safety Analysis Limit Value		
Typical flow channel	1.3	1.36[a]
Thimble (cold wall) flow channel	1.3	1.34[a]
Minimum DNBR at nominal conditions		
Typical flow channel	2.06	2.23 (1.98)[d]
Thimble (cold wall) flow channel	1.72	2.07 (1.87)[d]
Coolant Flow		
Total thermal flow rate (10^6 lb_m /hr)	142.1	145.8[e]
Effective flow rate for heat transfer (10^6 lb_m /hr)	133.9	136.3[e]
Effective flow area for heat transfer (ft^2)	51.1	51.1
Average velocity along fuel rods (ft/sec)	16.7	17.1[e]
Average mass velocity (10^6 $lb_m/hr\text{-}ft^2$)	2.62	2.68[e]
Coolant Temperature		
Nominal inlet (°F)	558.8	559.6[e]
Average rise in vessel (°F)	59.4	57.8[e]
Average rise in core (°F)	62.6	61.1[e]
Average in core (°F)	591.8	591.3[e]
Average in vessel (°F)	588.5	588.5

TABLE 4-1
(Sheet 2 of 2)

THERMAL AND HYDRAULIC EVALUATION TABLE

Design Parameters	Seabrook UFSAR	Seabrook Revised
Heat Transfer		
Active heat transfer, surface area (ft^2)	59,700	59,700
Average heat flux (Btu/hr-ft^2)	189,800	189,800
Maximum heat flux for normal operation (Btu/hr-ft^2)	440,300[b]	474,400[c]
Average linear power (Kw/ft)	5.44	5.44
Peak linear power for normal operation (Kw/ft)	12.6[b]	13.6[c]
Peak linear power resulting from overpower transients/operator errors, assuming a maximum over power of 118% (Kw/ft)	18.0	19.0
Peak linear power for prevention of centerline melt (Kw/ft)	>18.0	>19.0[f]
Fuel Central Temperature		
Peak temperature at peak linear power for prevention of centerline melt (°F)	4700	4654[f]

a For conditions outside the range of applicability of WRB-1, the W-3 correlation is used with a correlation limit of 1.45 in the pressure range of 500 to 1000 psia and 1.30 for pressures above 1000 psia. The Bowring correlation with a DNBR limit of 1.30 was used for the steam line break analysis.

b This limit is associated with the value of $F_Q = 2.32$.

c This limit is associated with the value of $F_Q = 2.50$.

d The parenthetical value refers to the edge of the axial flux difference LCO band.

e At minimum measured flow conditions.

f Cycle dependent; calculated by FROSSTEY-2.

5.0 ACCIDENT ANALYSES

This section of the report presents an evaluation of the accidents and transients and is organized in a format similar to Chapter 15 of the Seabrook Station Updated Final Safety Analysis Report (UFSAR), Revision 2[1]. Each section presents a discussion of the impact of the revised input parameters and assumptions listed in Section 3. The results from the revised analysis for the most limiting event in each category are presented.

Tables 5.0-1 and 5.0-2 lists the pertinent plant parameters utilized in the accident analyses. Specific parameters that influence the results of the safety analysis include: 1) initial conditions, 2) power distributions, 3) reactivity coefficients, 4) RCCA insertion characteristics, 5) trip setpoints and time delays, and component response times and capacities. These are discussed in each of the following sections.

5.0.1 Initial Conditions

Tables 5.0-1 and 5.0-2 provide a list of conditions representing nominal plant parameters. These parameters also represent a set of initial conditions for the accidents and transients. Uncertainties in these parameters are accounted for either through RTDP or in the initial conditions selected for the transient cases. The following uncertainties are considered:

a.	Core power	±2 percent allowance for calorimetric error
b.	Average RCS temperature	±5.8°F allowance for controller deadband and measurement error and steam generator fouling penalty
c.	Pressurizer pressure	±50 psi allowance for steady-state fluctuations and measurement error

For application of uncertainties in RTDP, refer to YAEC-1849P[4].

5.0.2 Power Distribution

The power distribution in the core, and in particular, the radial peaking factor ($F_{\Delta H}$) and the total peaking factor (F_q), are of major importance in determining the transient margin. Initial power distributions for the transients are selected from a range of possible

conditions within the allowable axial flux difference LCO band. Such a band, corresponding to Wide-Band operation for Seabrook Station, is illustrated in Figure 5.0-5. Power distributions used to generate the axial flux difference LCO band consider both steady-state operation and xenon transients. Details of the method for treating power distributions are provided in YAEC-1854P[7].

The radial peaking factor ($F_{\Delta H}$), the total peaking factor (F_q), and the axial flux difference LCO band are controlled through the COLR. Transient power peaking involving rod motion or rod misalignment is explicitly treated on an event-by-event basis.

5.0.3 Reactivity Coefficients Assumed in the Accident Analyses

The transient response of the reactor system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values, whereas in the analysis of other events, conservatism requires the use of small reactivity coefficient values. The values used for each accident are given in Table 5.0-2. Conservative combinations of parameters are used for each event selected on a case-by-case basis.

5.0.4 Rod Cluster Control Assembly 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. Another critical parameter is the time of insertion up to the dashpot entry, or approximately 85 percent of the rod cluster travel. For accident analyses, the insertion time to dashpot entry is conservatively taken as 2.4 seconds. The Rod Cluster Control Assembly position versus time assumed in accident analyses is shown in Figure 5.0-2.

Figure 5.0-3 illustrates the fraction of total negative reactivity insertion versus normalized rod position for a core where the axial power distribution is skewed to the bottom. This curve is used to compute the negative reactivity insertion versus time following a reactor trip, for the majority of cases presented in Section 5.

There is inherent conservatism in the use of Figure 5.0-3, particularly for DNB related events which are typically limiting for top skewed power distributions. For DNB related events a curve based on a slightly bottom skewed shape was used.

The normalized Rod Cluster Control Assembly negative reactivity insertion versus time is shown in Figure 5.0-4. The curve shown in this figure was obtained from Figures 5.0-2 and 5.0-3. Transient analyses performed with less conservative yet still bounding scram curves are specifically identified in subsequent sections. A total negative reactivity insertion following a trip of 4 percent ΔK is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available. For Figures 5.0-2 and 5.0-3, the rod cluster control assembly drop time is normalized to 2.4 seconds.

5.0.5 Trip Points and Time Delays to Trip Assumed in Accident Analyses

A reactor trip signal acts to open two trip breakers connected in series feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the Rod Cluster Control Assemblies, which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached at the sensor to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 5.0-3. The Overtemperature ΔT and Overpower ΔT trip functions are illustrated in Figure 5.0-1.

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant Technical Specifications and Core Operating Limits Report.

In the analysis of the Section 5 events, control system action is considered only if that action results in more severe accident results. No credit is taken for control system operation if that operation mitigates the results of an accident.

5.0.6 Component Response Times and Capacities

A tabulation of the component response-times and design capacities, as assumed for the various accidents, is presented in Table 5.0-4.

TABLE 5.0-1

NOMINAL VALUES OF PERTINENT PLANT PARAMETERS UTILIZED IN THE ACCIDENT ANALYSES

Thermal Power (MWt)	3411
Core inlet temperature (°F)	559.6
Vessel average temperature (°F)	588.5
Reactor Coolant System pressure (psia)	2250
Reactor coolant flow per loop (gpm)	98,200*
Steam flow from NSSS (lb/hr)	15,140,000
Steam pressure (psia)	1000
Assumed feedwater temperature at steam generator inlet (°F)	440
Average core heat flux (Btu/hr-ft^2)	189,800

* Minimum measured flow used in RTDP.

TABLE 5.0-2
(Sheet 1 of 3)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

FAULTS	COMPUTER CODES UTILIZED	REACTIVITY COEFFICIENTS ASSUMED: MODERATOR TEMPERATURE	REACTIVITY COEFFICIENTS ASSUMED: DOPPLER	INITIAL CORE THERMAL POWER OUTPUT ASSUMED %
5.1 Increase in Heat Removal by the Secondary System				
- Feedwater System Malfunction Causing an Increase in Feedwater Flow	RETRAN, VIPRE	Most Negative	Least Negative	0 and 100
- Excessive Increase in Secondary Steam Flow	RETRAN, VIPRE	Most and Least Negative	Least Negative	100
- Accidental Depressurization of the Main Steam System	Not Reanalyzed(1)	---	---	---
- Steam System Piping Failure	RETRAN, VIPRE, STAR	Most Negative	Most Negative	0
5.2 Decrease in Heat Removal by the Secondary System				
- Loss of External Load and/or Turbine Trip	RETRAN	Most and Least Negative	Most and Least Negative	100
- Loss of Nonemergency AC Power to the Station Auxiliaries	RETRAN, VIPRE	Most Positive	Least Negative	100
- Loss of Normal Feedwater Flow	RETRAN, VIPRE	Most Positive	Least Negative	100
- Feedwater System Pipe Break	RETRAN, VIPRE	Most Positive	Least Negative	100

TABLE 5.0-2
(Sheet 2 of 3)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

FAULTS	COMPUTER CODES UTILIZED	REACTIVITY COEFFICIENTS ASSUMED: MODERATOR TEMPERATURE	REACTIVITY COEFFICIENTS ASSUMED: DOPPLER	INITIAL CORE THERMAL POWER OUTPUT ASSUMED %
5.3 Decrease in Reactor Coolant System Flow Rate				
- Partial and Complete Loss of Forced Reactor Coolant Flow	LOFTRAN, RETRAN, CHIC-KIN,VIPRE	Most Positive		70,100
- Reactor Coolant Pump Shaft Seizure (Locked Rotor)	RETRAN, CHIC-KIN, VIPRE	Most Positive	Least Negative	100
- Reactor Coolant Pump Shaft Break	RETRAN (Only the Core Flow Coastdown was Reanalyzed)	---	---	100
5.4 Reactivity and Power Distribution Anomalies				
- Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low power Startup Condition	SIMULATE, CHIC-KIN, VIPRE	Most Positive	Least Negative	0
- Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power	RETRAN, VIPRE, CHIC-KIN	Most and Least Negative	Most and Least Positive	10,70,100
- Control Rod Misalignment	VIPRE, SIMULATE, RETRAN	---	Least Negative	50 to 100
- Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	Not Reanalyzed(1)	---	---	---

TABLE 5.0-2
(Sheet 3 of 3)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

FAULTS	COMPUTER CODES UTILIZED	REACTIVITY COEFFICIENTS ASSUMED: MODERATOR TEMPERATURE	REACTIVITY COEFFICIENTS ASSUMED: DOPPLER	INITIAL CORE THERMAL POWER OUTPUT ASSUMED %
- Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	Not Reanalyzed(1)	---		
- Spectrum of Rod Cluster Control Assembly Ejection Accidents	STAR, CHIC-KIN, VIPRE	Predicted values plus uncertainty	Predicted values plus uncertainty	0 and 100
5.5 Increase in Reactor Coolant Inventory				
- Inadvertent Operation of ECCS During Power Operation	Not Reanalyzed(1)	---	---	---
5.6 Decrease in Reactor Coolant Inventory				
- Inadvertent Opening of a Pressurizer Safety or Relief Valve	RETRAN, VIPRE	Most Positive	Least Negative	100
- Steam Generator Tube Rupture	Not Reanalyzed(1)	---	---	---
- Loss-of-Coolant Accident Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant System	See separate report from Westinghouse	---	---	

NOTES:

(1)These events have not been reanalyzed because they are not affected by the changes described in Section 3 or they are bounded by the analyses of other events.

TABLE 5.0-3

TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

Trip Function	Limiting Trip Point Assumed In Analysis	Time Delays (Seconds)
Power Range High Neutron Flux, High Setting	118%	0.5
Power Range High Neutron Flux, Low Setting	35%	0.5
High Neutron Flux, P-8	50%	0.5
Overtemperature ΔT	Variable	6.0*
Overpower ΔT	Variable	6.0*
High pressurizer pressure	2425 psia	2.0
Low pressurizer pressure	1935 psia	2.0
Low reactor coolant flow (from loop flow detectors)	87% loop flow	1.0
Undervoltage Trip	70% nominal	1.5
Turbine Trip	Not applicable	1.0
Low-low steam generator level	0% of narrow range level span**	2.0
High steam generator level trip of the feedwater pumps and closure of feedwater system valves, and turbine trip	94% of narrow range level span	2.0
Safety Injection Actuation	1665 psia	30.0

* Total time delay (including RTD time response and trip circuit channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall.

** Zero percent of the narrow range level span is the limiting trip point based on the feedwater system pipe break analysis. All other analyses assume a trip point corresponding to 10 percent of narrow range span.

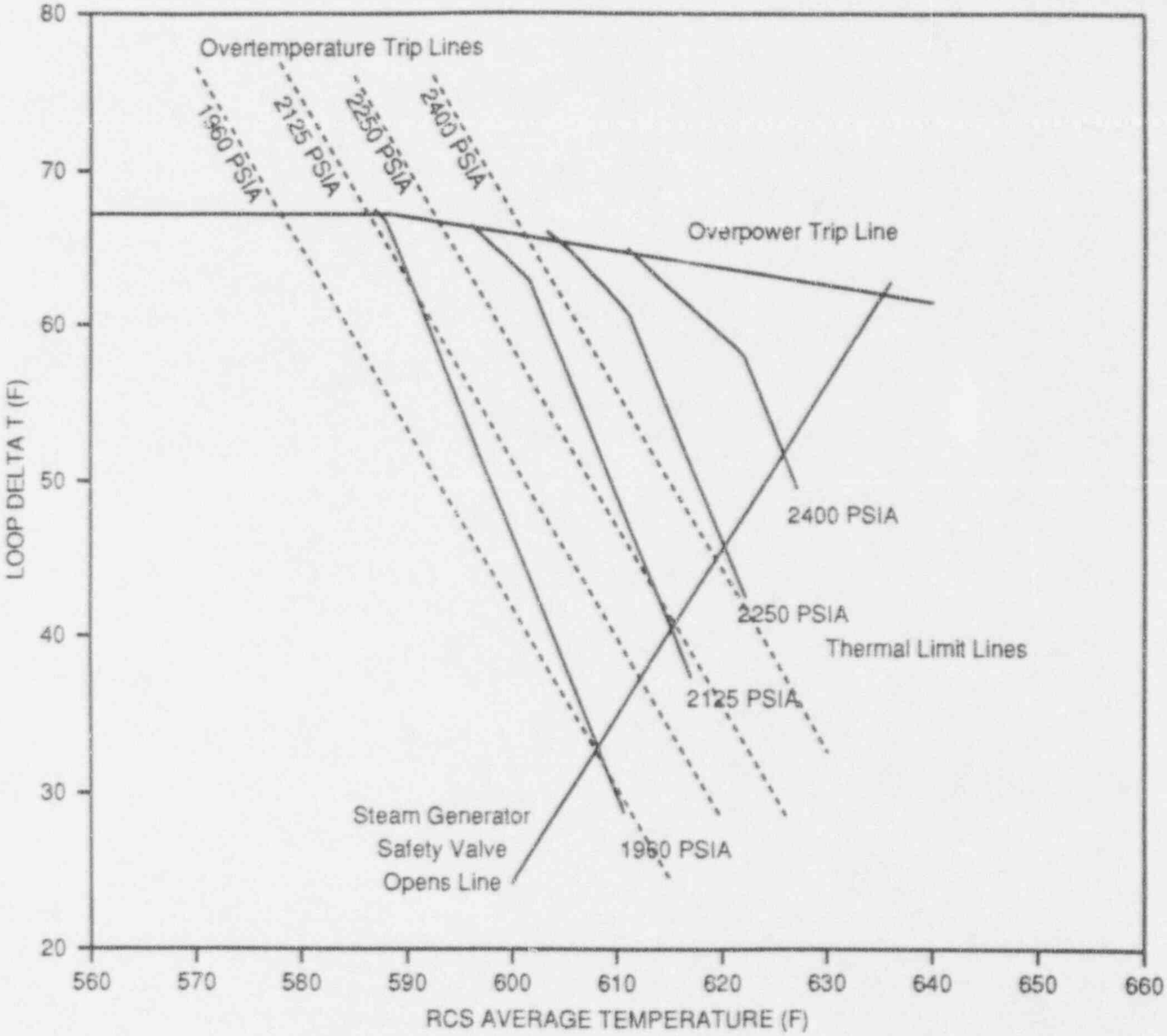
TABLE 5.0-4

COMPONENT TIMES AND CAPACITIES

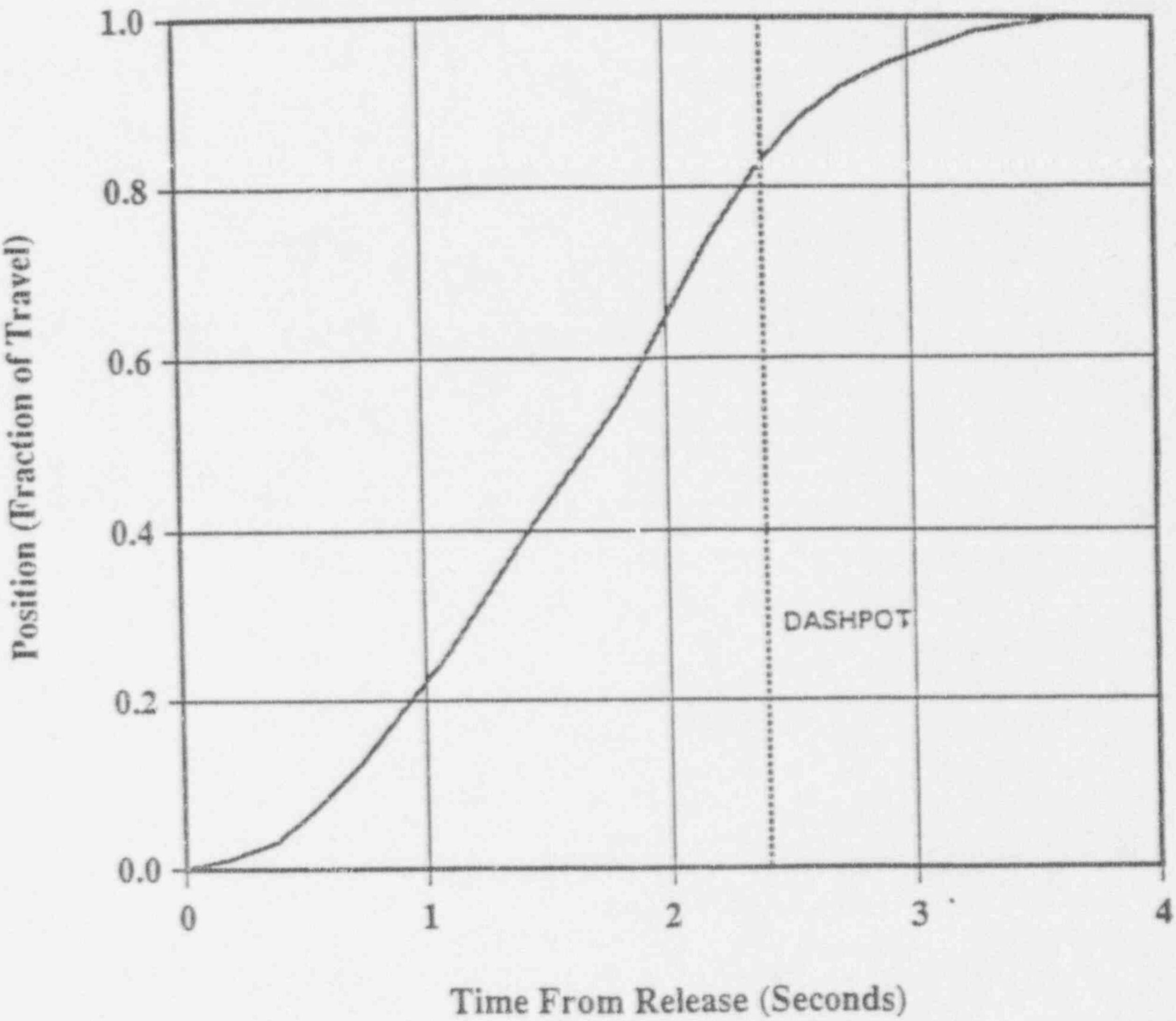
COMPONENT	RESPONSE TIME	CAPACITY	TEST PROVISIONS
Main Steam line Isolation Valves	2 second logic and delay 5 second closure	- -	See UFSAR Table 14.2-3, item 13
Main Feedwater Isolation Valves	2 second logic and delay 5 second closure	- -	See UFSAR Table 14.2-3, item 14
Pressurizer Power-Operated Relief Valves	-	2 Valves @ 210000 lbm/hr	See UFSAR Table 14.2-3, item 2
Pressurizer Safety Valves(2)	-	3 Valves @ 420000 lbm/hr	See UFSAR Table 14.2-3, item 40
Steam Generator Safety Valves(2)	-	120% of rated flow power steam flow (rated flow = 15.4×10^6 lbm/hr)	See UFSAR Table 14.2-3, item 40
Emergency Feedwater(1)	75 second delay with or without offsite power	Feedline rupture - 470 gpm minimum total flow to two intact steam generators with two EFW pumps operational and 470 gpm minimum total flow to three intact steam generators with one EFW pump operational. Loss of feedwater with AC power: 650 gpm total minimum flow to all steam generators with one EFW pump operational. Loss of feedwater without AC power: 650 gpm total minimum flow to all steam generators with one EFW pump operational.	See UFSAR Table 14.2-3, item 14

(1) For Steam line Rupture, see Subsection 5.1.5

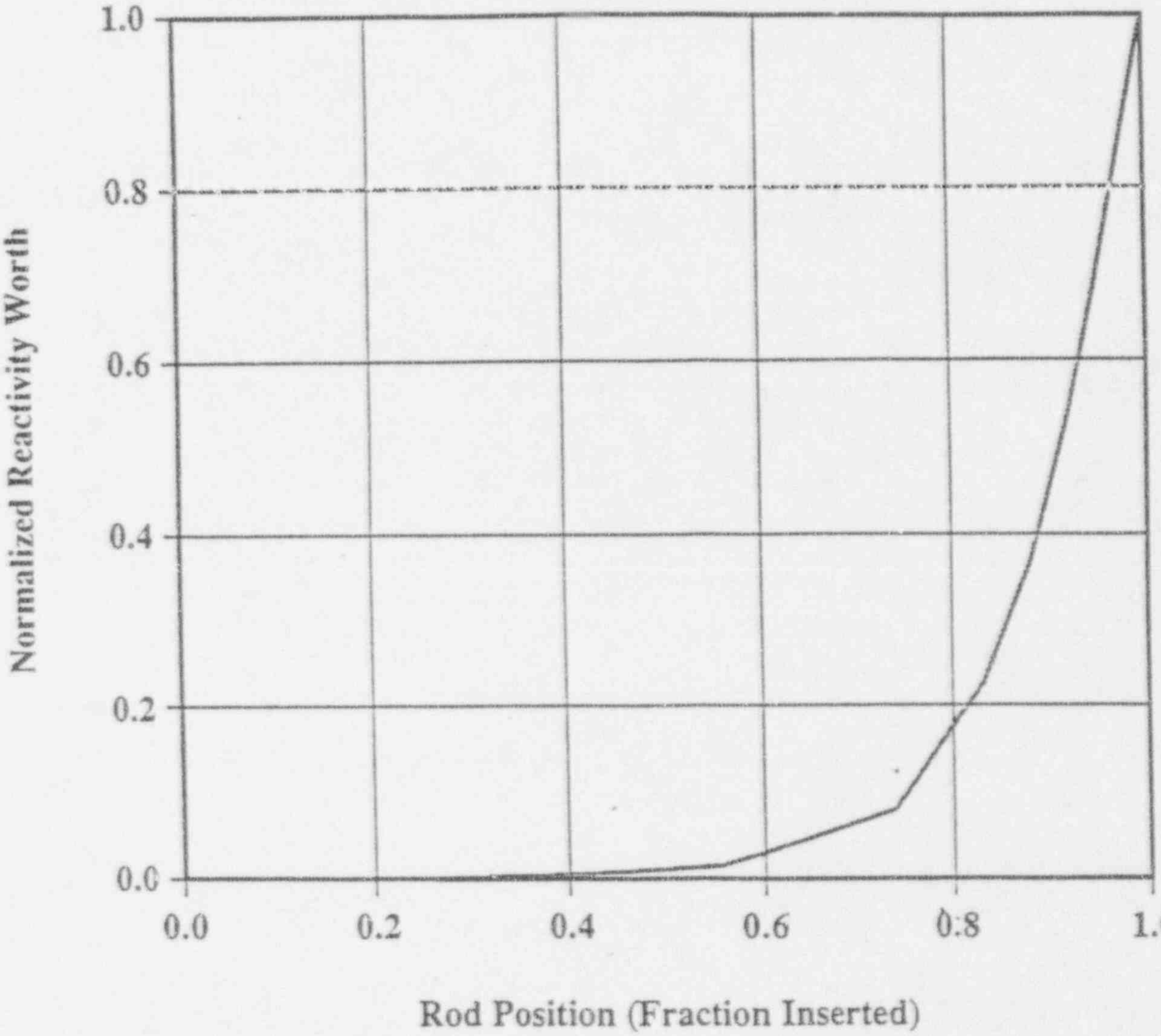
(2) Allowances of 3% setpoint tolerance and 3% accumulation for all code safety valves are assumed.



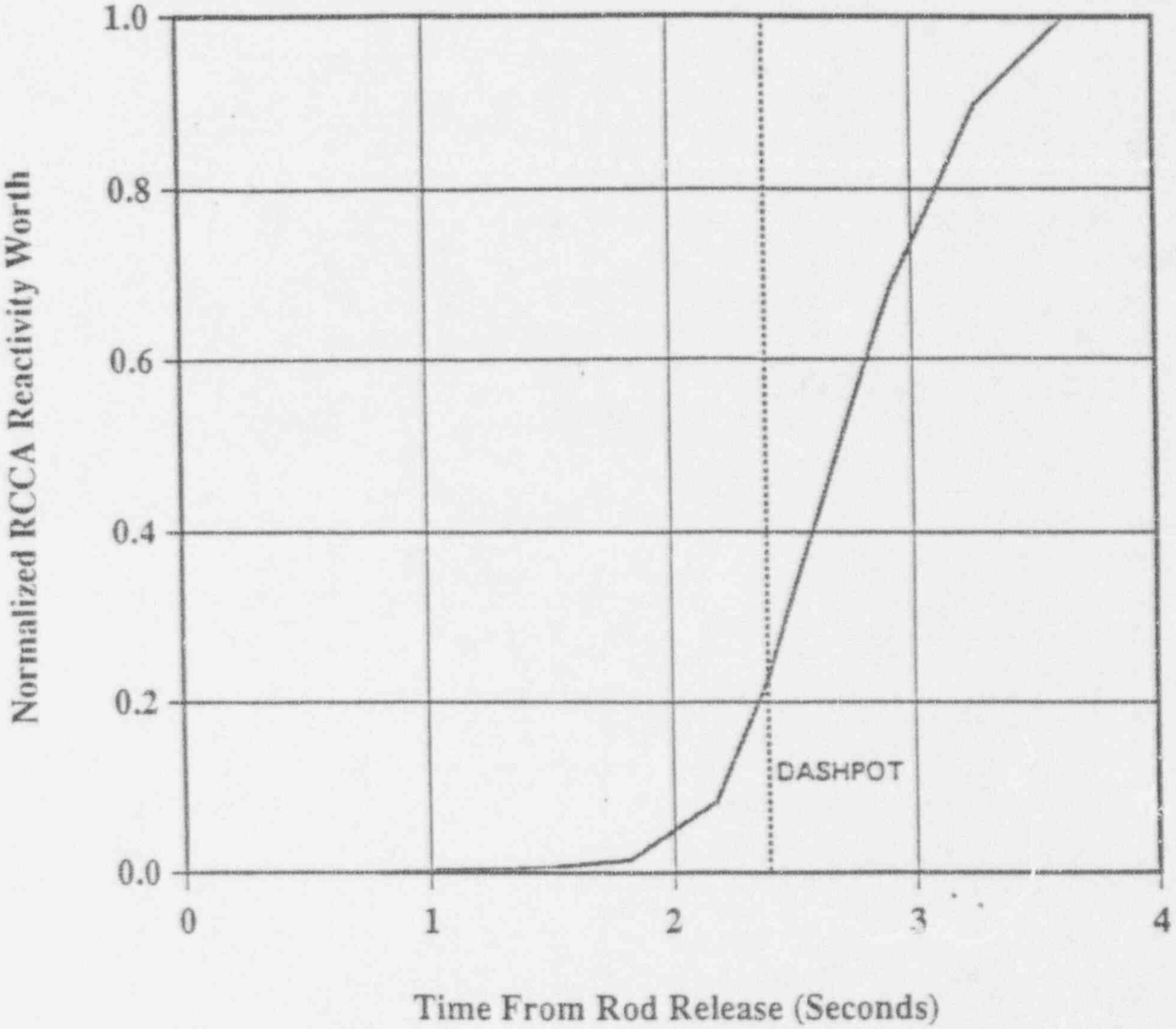
SEABROOK STATION	Illustration of Overtemperature and Overpower Delta-T Protection FIGURE 5.0-1



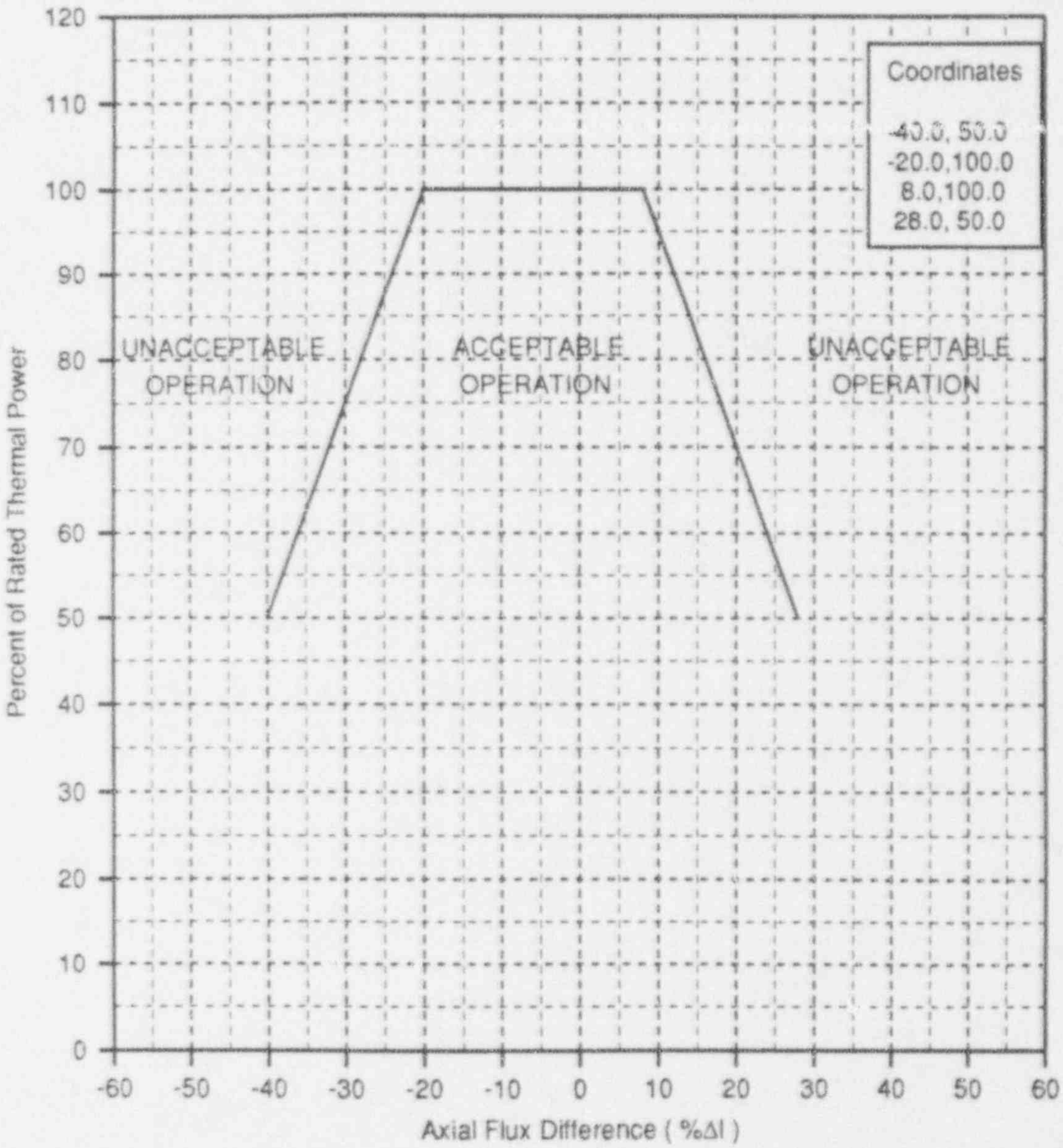
SEABROOK STATION	RCCA Position Versus Time to Dashpot	
		FIGURE 5.0-2



SEABROOK STATION	Normalized RCCA Reactivity Worth Versus Fraction Inserted
	FIGURE 5.0-[illegible]



SEABROOK STATION	Normalized RCCA Bank Reactivity Worth Versus Time from Start of Rod Motion
	FIGURE 5.0-4



SEABROOK STATION

Illustration of Allowable
Axial Flux Difference Limits
as a Function of Rated Thermal Power

FIGURE 5.05

5.1 INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

A number of events have been postulated which could result in an increase in heat removal from the Reactor Coolant System by the secondary system. Detailed analyses are presented for several such events which have been identified as limiting cases. Discussions of the following reactor coolant system cooldown events are presented in this section:

a. Feedwater system malfunction causing a reduction in feedwater temperature
b. Feedwater system malfunction causing an increase in feedwater flow
c. Excessive increase in secondary steam flow
d. Inadvertent opening of a steam generator relief or safety valve
e. Steam system piping failure.

The above are considered to be ANS Condition II events, with the exception of a major steam system pipe break, which is considered to be an ANS Condition IV event. Events b, c, and e were reanalyzed and results are presented in this section. Event a is bounded by events b and c; event d is bounded by event e which meets the criteria of ANS Condition II events.

5.1.1 Feedwater System Malfunctions Causing a Reduction in Feedwater Temperature

The decrease in feedwater temperature transient is bounded by the increase in feedwater flow event (Subsection 5.1.2), and the increase in secondary steam flow event (Subsection 5.1.3). The event has therefore not been reanalyzed and the previous conclusions of the UFSAR are bounded by the analysis results for the Excessive Increase in Secondary Steam Flow (Section 5.1.3).

5.1.2 Feedwater System Malfunctions Causing an Increase in Feedwater Flow

5.1.2.1 Identification of Causes and Accident Description

Additions of excessive feedwater could cause an increase in core power by decreasing reactor coolant temperature under the influence of a negative moderator temperature coefficient. Such transients are attenuated by the thermal capacity of the secondary plant and of the Reactor Coolant System (RCS). The overpower/overtemperature protection (neutron overpower, Overtemperature and Overpower ΔT trips) prevent any power increase which could lead to a DNBR less than the 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 RCS 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 RCS 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 trips the turbine and reactor, and 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 ANS Condition II event, a fault of moderate frequency.

5.1.2.2 Analysis of Effects and Consequences

a. Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed by using the detailed digital computer code RETRAN[9]. This code simulates a multi-loop system, neutron kinetics, the 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.

The system is analyzed to demonstrate plant behavior in the event that excessive feedwater addition occurs, due to a control system malfunction or operator error which allows a feedwater control valve to open fully. Two cases are considered as follows:

1. Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions assuming a conservatively large negative moderator temperature coefficient.

2. Accidental opening of one feedwater control valve with the reactor in automatic control at full power.

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 zero load condition, feedwater temperature is at a conservatively low value of 100°F.

4. No credit is taken for the heat capacity of the RCS 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 an overtemperature or turbine trip resulting from high-high steam generator water level condition. No single active failure will prevent operation of the Reactor Protection System.

b. Results

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power and the above mentioned assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate analyzed in Subsection 5.4.1, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition," and therefore, the results of the analysis are not presented here. It should be noted that if the incident occurs with the unit just critical at no-load, the reactor may be tripped by the power range high neutron flux trip (low setting) assumed to occur at 35 percent of nominal full power.

The full power case (maximum reactivity feedback coefficients, with rod control) gives the largest reactivity feedback and results in the greatest power increase. Assuming the reactor to be in the manual rod control mode results in a similar transient.

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. This prevents continuous addition of the feedwater. In addition, a turbine trip is initiated.

Following turbine trip, the reactor will be automatically tripped, either directly due to turbine trip or due to an Overtemperature ΔT signal. If the reactor were in the automatic control mode, the control rods would be inserted following turbine trip, and the ensuing transient would then be similar to a loss of load (turbine trip event) as analyzed in Subsection 5.2.3.

Transient results (see Figure 5.1-1) show the increase in nuclear power associated with the increased thermal load on the reactor. The DNB ratio does not drop below the safety analysis limit value. Following the reactor trip, the plant approaches a stabilized condition; standard plant shutdown procedures may then be followed to further cooldown the plant.

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. The peak fuel temperature will thus remain well below the fuel melting temperature.

The transient results show that DNB does not occur at any time during the excessive feedwater flow incident; thus, the ability of the primary coolant to remove heat from the fuel rod is not reduced. The fuel cladding temperature, therefore, does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 5.1-1.

5.1.2.3 Radiological Consequences

No fuel failure and radioactivity releases are anticipated as a direct result of this malfunction. Consequently, no radiological consequences are predicted.

5.1.2.4 Conclusions

The results of the analysis show that the DNB ratios encountered for an excessive feedwater addition at power are above the safety analysis limit value; hence, no fuel or clad damage is predicted. Additionally, it has been shown that the reactivity insertion rate which occurs at no-load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from a subcritical condition.

5.1.3 Excessive Increase in Secondary Steam Flow

5.1.3.1 Identification of Causes and Accident Description

An excessive increase in secondary system steam flow (excessive load increase incident) is defined as a rapid increase in 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 in the range of 15 percent to 100 percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the Reactor Protection System. Steam flow increases greater than 10 percent are evaluated in Subsection 5.1.5.

This transient 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 reactor coolant condition signals, i.e., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following Reactor Protection System (RPS) signals:

- Overpower ΔT
- Overtemperature ΔT
- Power range high neutron flux

An excessive load increase event is considered to be an ANS Condition II event, a fault of moderate frequency.

5.1.3.2 Analysis of Effects and Consequences

a. Method of Analysis

This accident is analyzed using RETRAN Code[9]. The code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and Feedwater System. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10 percent step load increase from rated load. These cases are as follows:

1. Reactor control in manual with the most positive MTC;
2. Reactor control in manual with the most negative MTC;
3. Reactor control in automatic with the most positive MTC; and,
4. Reactor control in automatic with the most negative MTC.

The cases with the most negative MTC result in the largest amount of reactivity feedback due to changes in coolant temperature. For the cases with automatic rod control, no credit was taken for ΔT trips on overtemperature or overpower in order to demonstrate the inherent transient capability of the plant. Under actual operating conditions, such a trip may occur, after which the plant would quickly stabilize.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit taken for pressurizer heaters. Initial operating conditions are assumed at extreme values consistent with the steady-state full power operation allowing for calibration and instrument errors. This results in minimum margin to core DNB at the start of the accident.

With the turbine governor valves fully open, the maximum steam flow will be 105 percent of the nominal. However, this analysis conservatively overestimates that a steam flow of 110 percent would be attained.

Normal Reactor Control Systems and Engineered Safety Systems are not required to function. The Reactor Protection System is assumed to be operable; however, reactor trip is not encountered for many cases due to the error allowances assumed in the setpoints. No single active failure will prevent the Reactor Protection System from performing its intended function.

The cases which assume automatic rod control are analyzed to insure that the worst case is presented. The automatic rod control function is not required for protection.

b. Results

Figures 5.1-2 and 5.1-3 illustrate the transient with the reactor in the manual control mode. As expected, for the most positive MTC case there is a power decrease due to the large decrease in the average core temperature. The DNBR decreases as a result of the drop in pressure, but remains above the safety analysis limit value. For the most negative MTC, manual rod control case, reactor power increases due to the moderator feedback. A reduction in DNBR is experienced but DNBR remains above the safety analysis limit value.

Figures 5.1-4 and 5.1-5 illustrate the transient assuming the reactor is in the automatic rod control mode and no reactor trip signals occur. Both the most positive and most negative MTC cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the safety analysis limit value.

For all cases except the most positive MTC and manual control (which results in a reactor trip on low pressurizer pressure), the plant reaches a stabilized condition at the higher power level. The calculated times are listed in Table 5.1-1. Normal plant operating procedures would then be followed to reduce power. Note that due to the measurement errors assumed in the setpoints, it is possible that reactor trip could actually occur for the automatic rod control cases due to rod motion. The plant would then reach a stabilized condition following the trip.

5.1.3.3 Radiological Consequences

No fuel failure and no radioactivity releases are anticipated as a direct result of this malfunction. Consequently, no radiological consequences are predicted.

5.1.3.4 Conclusions

The excessive load increase incident is an overpower transient for which the fuel temperature will rise. Reactor trip may not occur for some of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Since DNB does not occur at any time during the excessive load increase transients, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

5.1.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

The inadvertent opening of a steam generator relief or safety valve is not reanalyzed, since the results of this event are bounded by the zero power steam line rupture discussed in Section 5.1.5. The opening of a steam generator relief or safety valve would cause a slower steam generator blowdown and RCS 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 DNBR 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 relief or safety valve.

5.1.5 Steam System Piping Failure

5.1.5.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam line would result in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity. If the most reactive Rod Cluster Control Assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam line rupture requires evaluation mainly because of the high power peaking factors which exist assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boron solution injection delivered by the Safety Injection System.

The limiting steam line break presented in this section corresponds to a double-ended rupture of the main steam line at the steam generator nozzle at zero power with offsite power available.

The analysis of a main steam line rupture is performed to demonstrate that the following criteria are satisfied:

a. Assuming a stuck RCCA with or without offsite power, and assuming a single failure in the Engineered Safety Features, the core remains in place and intact. Radiation doses do not exceed the guidelines of 10 CFR 100.

b. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no DNB occurs for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

A major steam line rupture is classified as an ANS Condition IV event.

Effects of minor secondary system pipe breaks are bounded by the analysis presented in this section. Minor secondary system pipe breaks are classified as Condition III events.

The major rupture of a steam line is the most limiting cooldown transient and is analyzed at zero power with no decay heat. Decay heat would retard the cooldown thereby reducing the return to power. A detailed analysis of this transient with the most limiting break size, a double-ended rupture, is presented here.

The following functions provide the protection for a steam line rupture:

a. Safety injection system actuation from any of the following:

    1. Two out of four low pressurizer pressure signals
    2. Two out of three high-1 containment pressure signals
    3. Two out of three low steam line pressure signals in any one loop.

b. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

c. 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, a safety injection signal will rapidly close all feedwater control valves and backup feedwater isolation valves and trip the main feedwater pumps.

d. Trip of the fast-acting Main Steam Isolation Valves (MSIVs) which are designed to close in less than 5 seconds after receipt of a signal on:

1. High-2 containment pressure
2. Safety injection system actuation derived from two out of three low steam line pressure signals in any one loop (above Permissive P-11)
3. Two out of three high negative steam pressure rate 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 any 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.

5.1.5.2 Analysis of Effects and Consequences

a. Method of Analysis

The thermal-hydraulic response for steam line break is calculated using RETRAN[(9)]. To assure a conservative power response following a return to critical, the RETRAN point kinetics model, with appropriate weighting factors derived from STAR[(26)], is used. In addition, the overall reactivity balance calculation in RETRAN includes a statistical treatment of uncertainties applied to the reactivity components. For cases where a return to power is predicted, a DNBR calculation is performed using the Bowring WSC-2 CHF correlation and VIPRE[(4)]. Conservative local peaking, obtained from a quasi-static SIMULATE3[(32)], are applied. Details of the above method is given in Reference 26.

Studies have been performed to determine the sensitivity of steam line break results to various assumptions[26,29]. Based upon these studies, the following conditions were assumed to exist at the time of a main steam break accident:

1. End-of-life shutdown margin at no-load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position.

2. A negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position.

   The core reactivity defects associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively weighted to obtain a conservative core power response based on the method described in Reference 26. Further, it was conservatively assumed that the core power distribution was uniform which causes underprediction of the reactivity feedback in the high power region near the stuck rod.

3. The limiting steam line break with return to power correspond to the case with offsite power available. The offsite power available case results in the greatest challenge to DNB based on the work presented in Reference 26.

4. Minimum safety injection flow capability corresponding to the most restrictive single failure in the Safety Injection System. The Emergency Core Cooling System (ECCS), consists of three systems: (1) the passive accumulators, (2) the Residual Heat Removal System and (3) the Safety Injection System. Only the Safety Injection System is modeled for the steam line break accident analysis.

   The actual modeling of the Safety Injection System in RETRAN is described as follows. The flow corresponds to that delivered by one train of ECCS with a 5% flow degradation. No credit has been taken for the low concentration borated water, which must be swept from the lines downstream of the refueling water storage tank prior to the delivery of highly borated water to the reactor coolant loops.

   For the case with offsite power available, the sequence of events is as follows. After the safety injection setpoint is reached, with appropriate delays for instrumentation, logic, and signal transport, one SI train starts. The volume

containing the low concentration borated water is swept before the 2,000 ppm boron solution from the refueling water storage tank reaches the core. This delay, described above, is inherently included in the modeling.

5. Since the steam generators are provided with integral flow restrictors with a 1.4 square foot throat area, any rupture with a break area greater than 1.4 square feet, regardless of location, would have the same effect on the NSSS as the 1.4 square foot break.

   Blowdown from the three intact steam generators through the main steam header is explicitly modelled. Blowdown of the intact steam generators is terminated by MSIV closure. All flow out the break is assumed to be dry steam to maximize the RCS cooldown and is computed using the Moody critical flow model.

6. For the DNBR calculation, power peaking factors corresponding to one stuck RCCA and nonuniform core inlet coolant temperatures are determined at the end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod.

7. A conservatively high emergency feedwater flow (2295 gpm) is assumed for the steam line rupture analysis, with 100 percent of this flow going to the broken loop. The enthalpy of the emergency feedwater is 50 Btu/lbm and the flow is assumed to start at the beginning of the transient. This maximizes the cooldown of the primary coolant.

b. <u>Results</u>

The calculated sequence of events is shown on Table 5.1-1. The results presented are a conservative indication of the events which would occur assuming a steam line rupture.

1. <u>Core Power and Reactor Coolant System Transient</u>

   Figure 5.1-6 shows the system transient following a main steam line rupture (complete severance of a pipe) at initial no-load conditions.

As shown in Figure 5.1-6, the core attains criticality with the RCCAs inserted (with the design shutdown margin assuming one stuck RCCA). A peak core power lower than the nominal full power value is attained.

It should be noted, that following a steam line break only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transient is over.

2. Margin to Critical Heat Flux

A DNB analysis was performed for this case. It was found that the DNB design basis was met, i.e., the minimum DNBR was greater than the safety analysis limit value.

5.1.5.3 Radiological Consequences

Input parameters and assumptions used in the radiological consequence analysis of this event have not changed from those used in the previous analysis shown in the UFSAR. Previous UFSAR results remain applicable.

5.1.5.4 Conclusions

The analysis has shown that the criteria stated in Subsection 5.1.5.1 are satisfied.

Although DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable and not precluded by the criteria, the above analysis, in fact, shows that the DNB design basis is met for any rupture assuming the most restrictive RCCA stuck in its fully withdrawn position.

The doses which have been calculated for the major secondary system pipe rupture are below the values specified in the applicable regulation, 10 CFR 100, "Reactor Site Criteria."

TABLE 5.1-1
(Sheet 1 of 2)

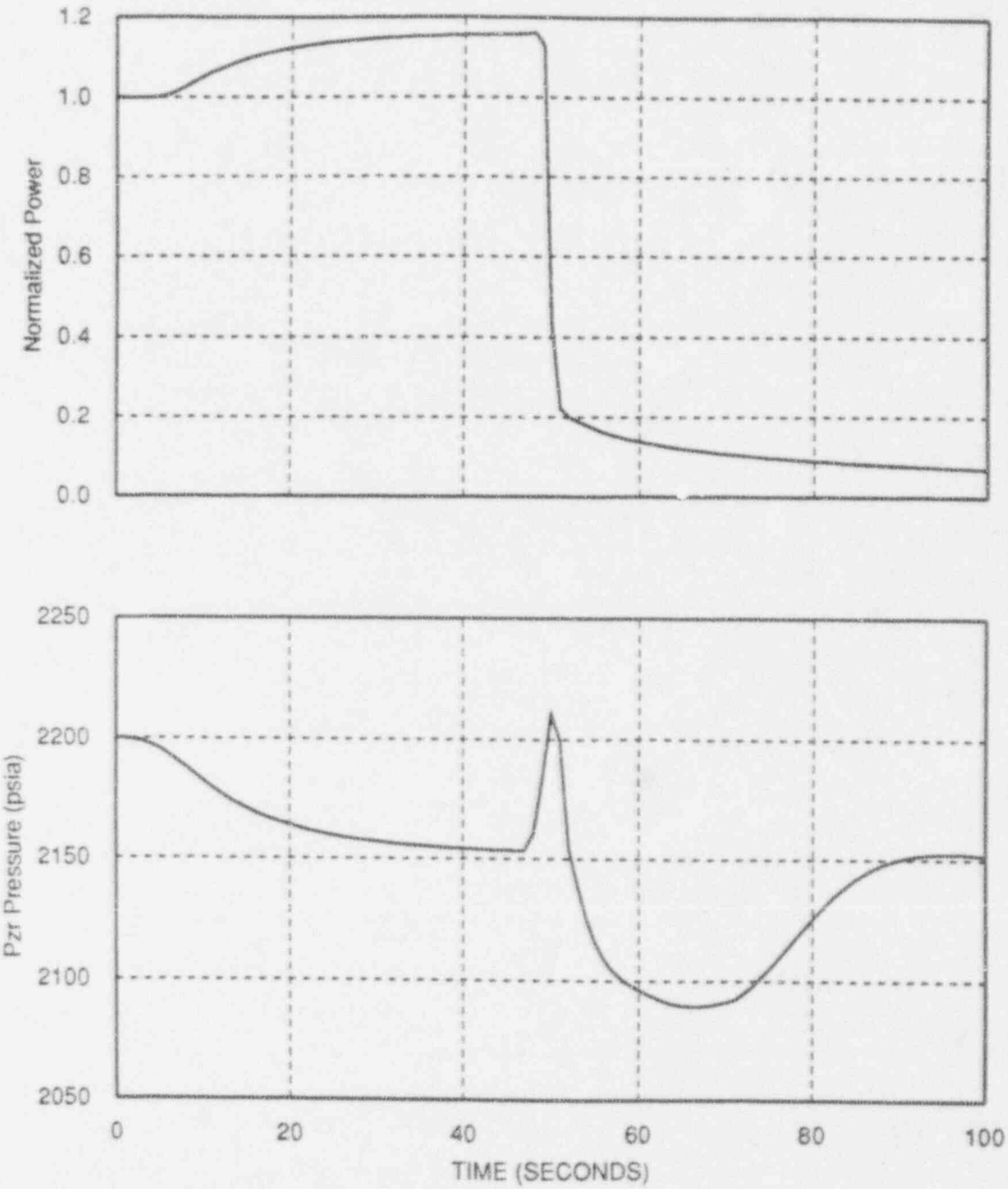
TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE AN INCREASE IN
HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
a. Excessive Feedwater flow at full power	One main feedwater control valve fails fully open	0.0
	High-high steam generator water level signal generated	46.4
	Turbine trip occurs due to high-high steam generator level	46.4
	Minimum DNBR occurs	40.5
	Reactor trip occurs	47.5
	Feedwater isolation valves fully closed	53.4
b. Excessive Increase in Secondary Steam Flow		
1. Manual Rod Control (most positive MTC)	10% step load increase	0.0
	Reactor trips on low pressurizer pressure	85.2
2. Manual Rod Control (most negative MTC)	10% step load increase	0.0
	Equilibrium conditions reached (approximate time only)	220
3. Automatic Rod Control (most positive MTC)	10% step load increase	0.0
	Equilibrium conditions reached (approximate time only)	400

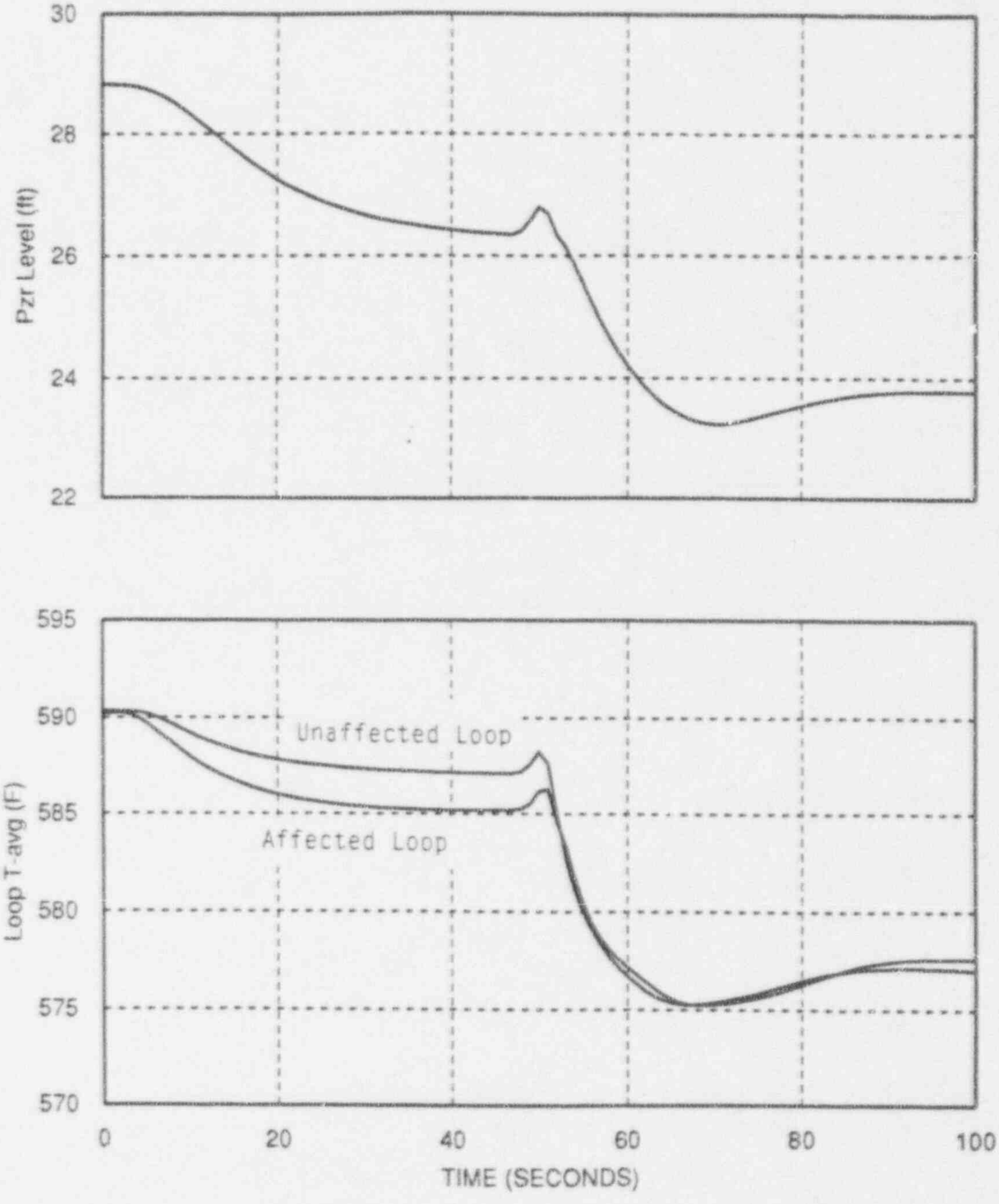
TABLE 5.1-1
(Sheet 2 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE AN INCREASE IN
HEAT REMOVAL BY THE SECONDARY SYSTEM

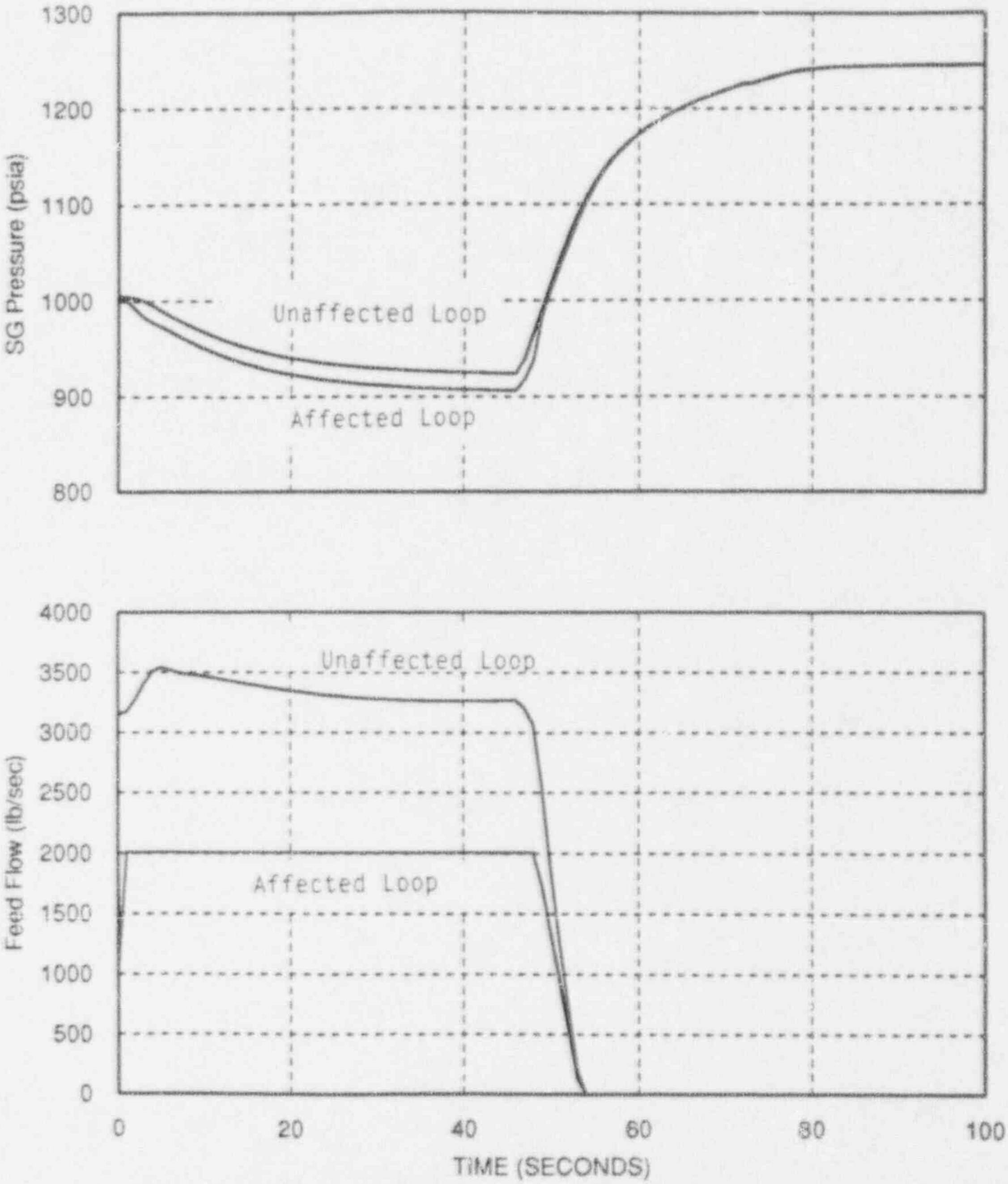
Accident	Event	Time (seconds)
4. Automatic Rod Control (most negative MTC)	10% step load increase	0.0
	Equilibrium conditions reached (approximate time only)	350
c. Steam System piping failure (with offsite power available)		
	Steam line ruptures	0
	Criticality attained	15.4
	SI flow begins	30.9
	Maximum DNBR occurs	58.2



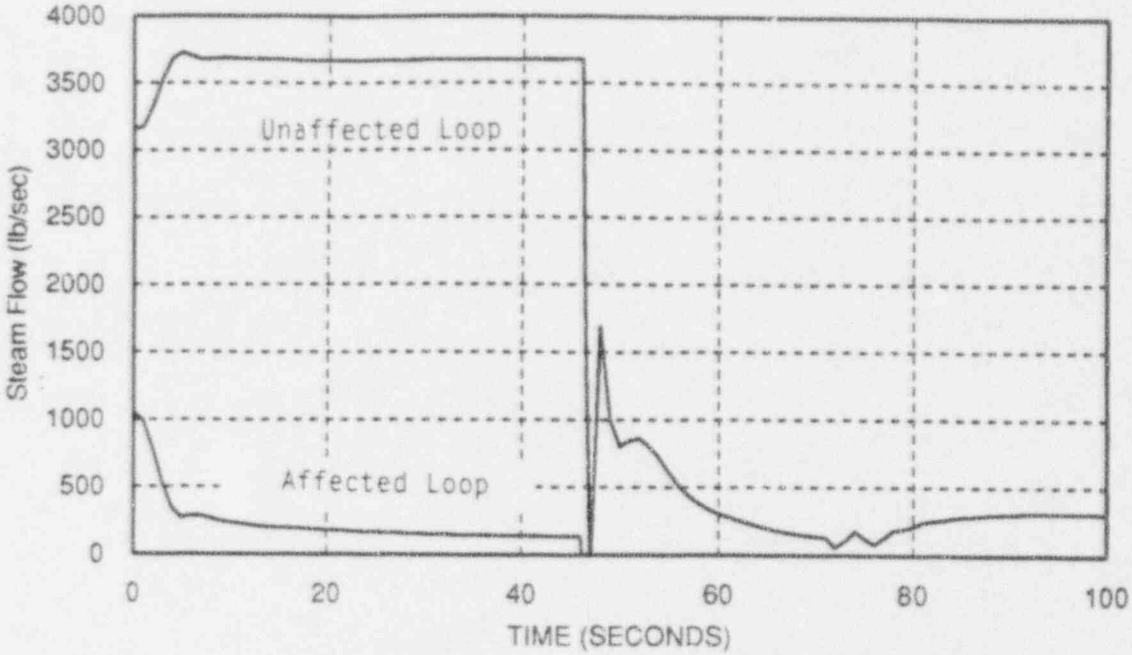
SEABROOK STATION	Feedwater Control Valve Malfunction (Failed Open), Reactor and Turbine Trip FIGURE 5.1-1 , Sh. 1



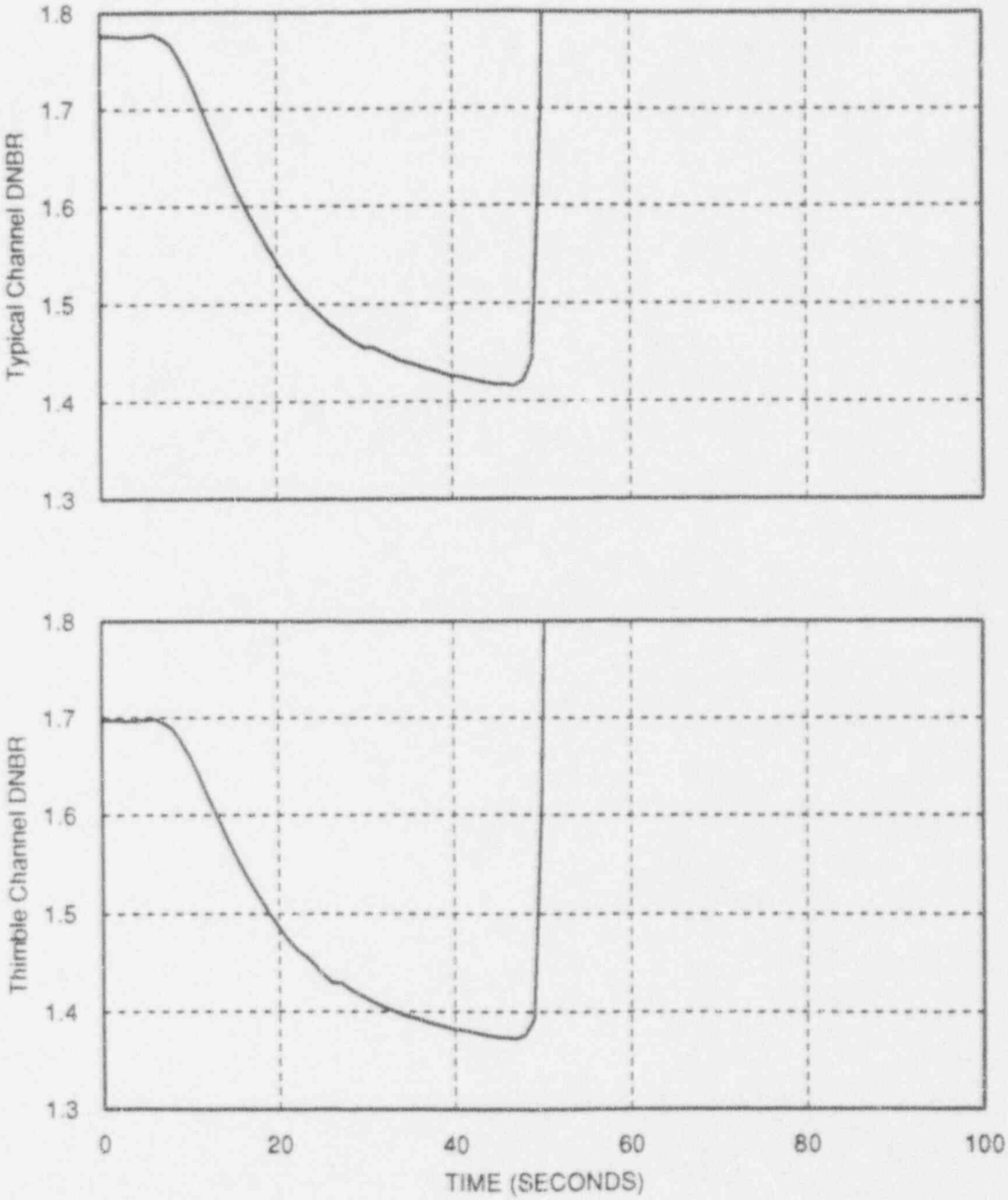
SEABROOK STATION	Feedwater Control Valve Malfunction (Failed Open), Reactor and Turbine Trip FIGURE 5.1-1 , Sh. 2



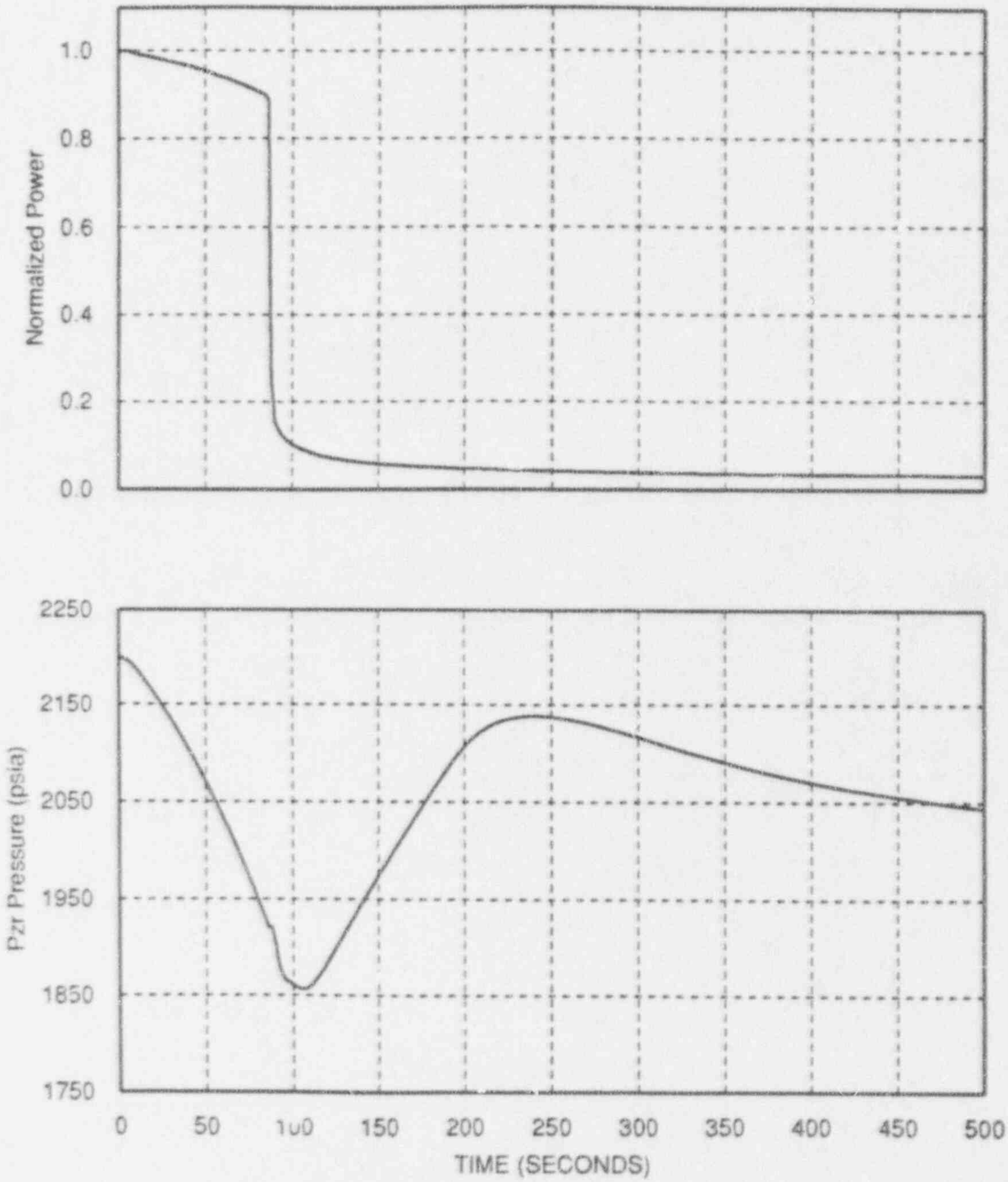
SEABROOK STATION	Feedwater Control Valve Malfunction (Failed Open), Reactor and Turbine Trip FIGURE 5.1-1 , Sh. 3



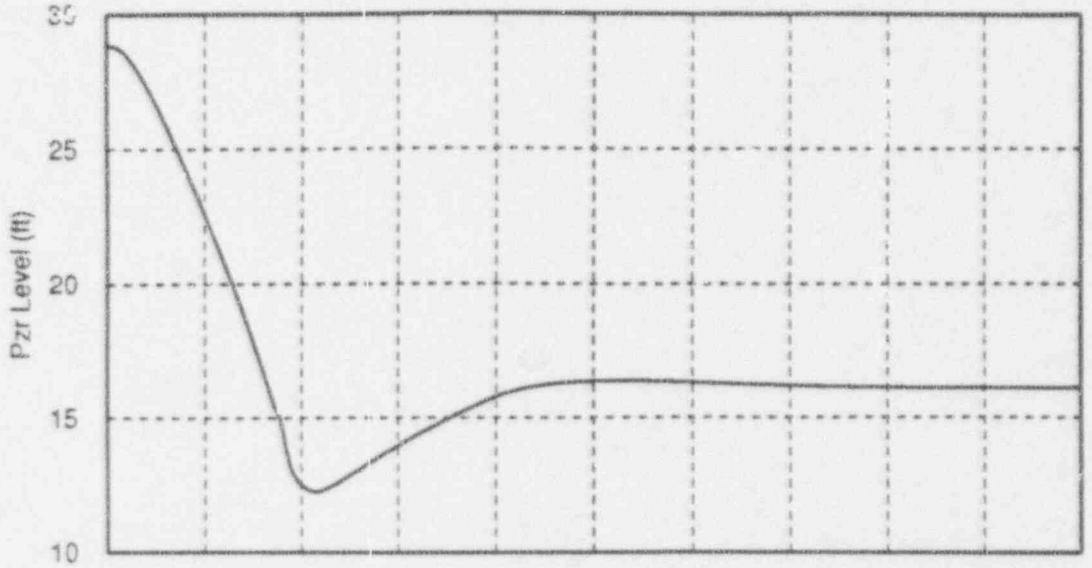
SEABROOK STATION	Feedwater Control Valve Malfunction (Failed Open), Reactor and Turbine Trip
	FIGURE 5.1-1 , Sh. 4

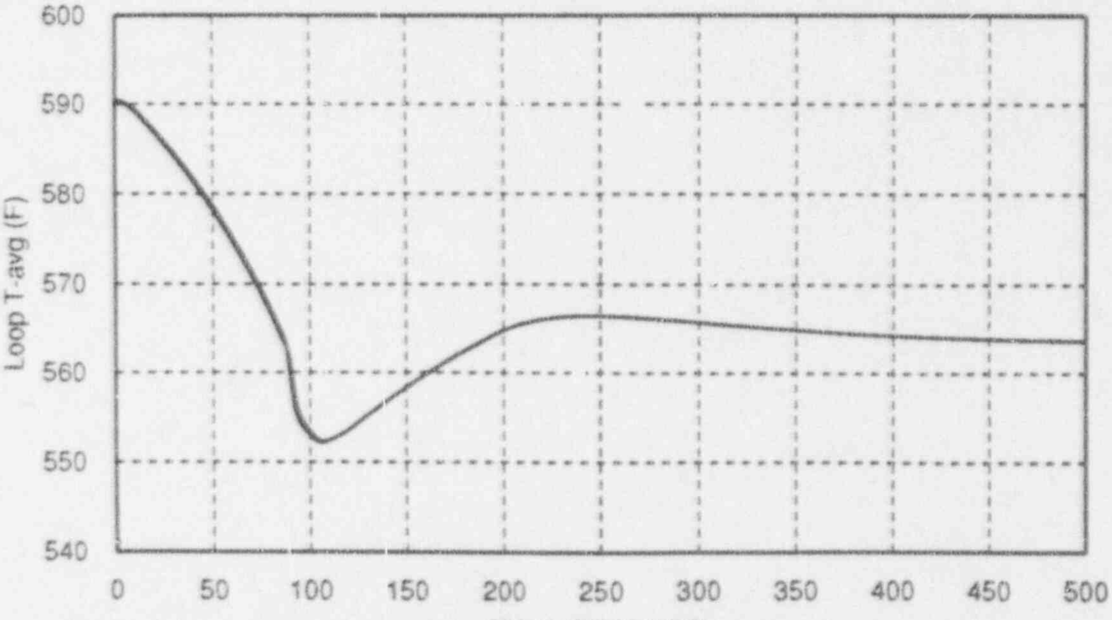


SEABROOK STATION	Feedwater Control Valve Malfunction (Failed Open), Reactor and Turbine Trip FIGURE 5.1-1, Sh. 5

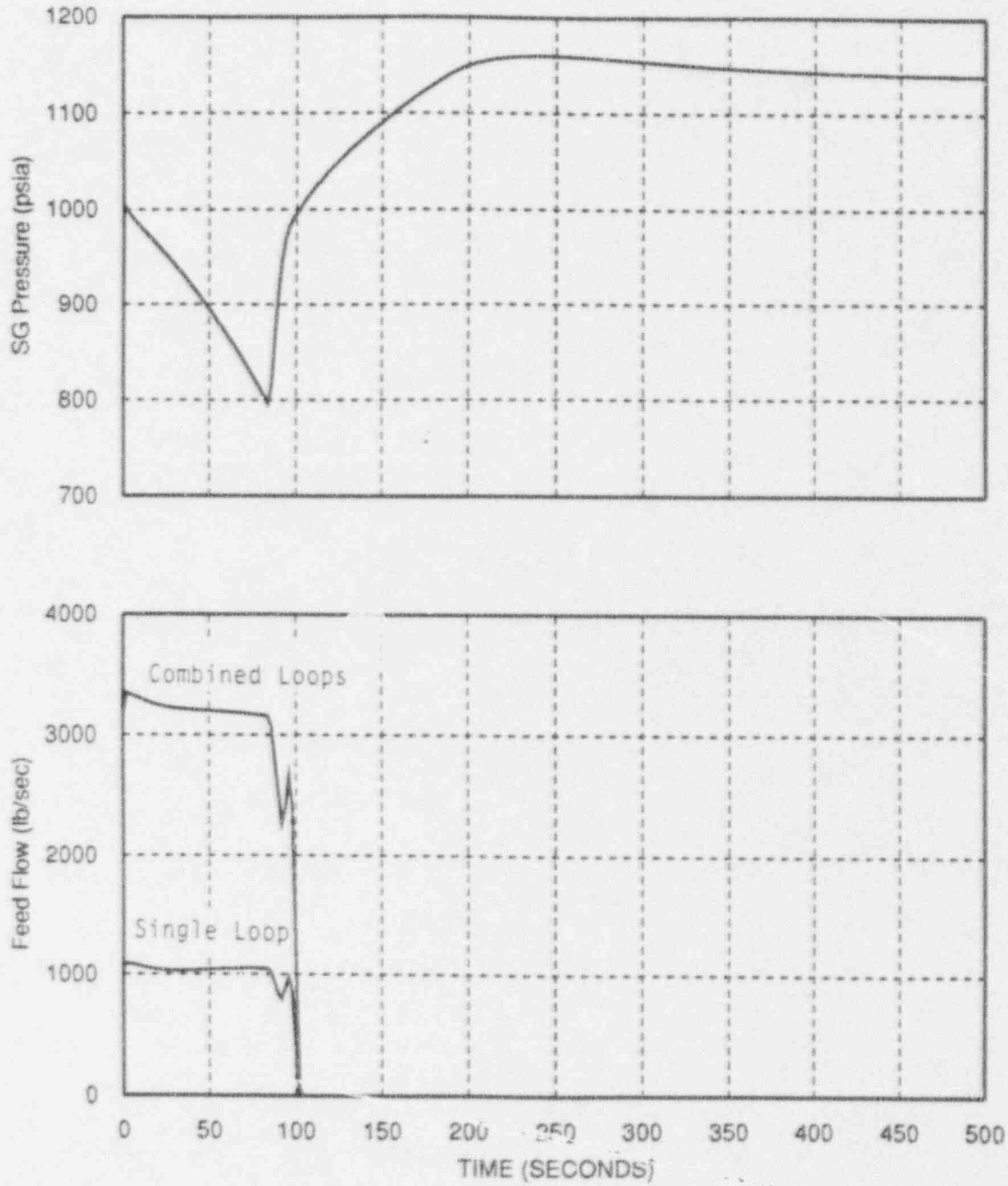


SEABROOK STATION	10% Step Load Increase Most Positive MTC Manual Rod Control FIGURE 5.1-2 , Sh. 1

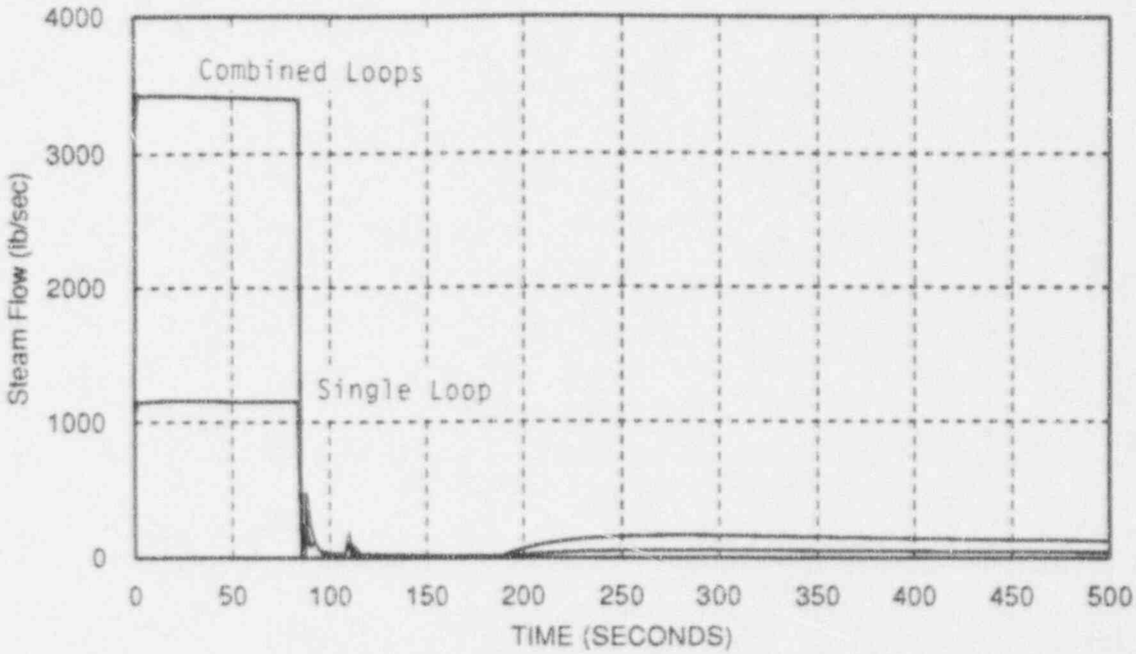




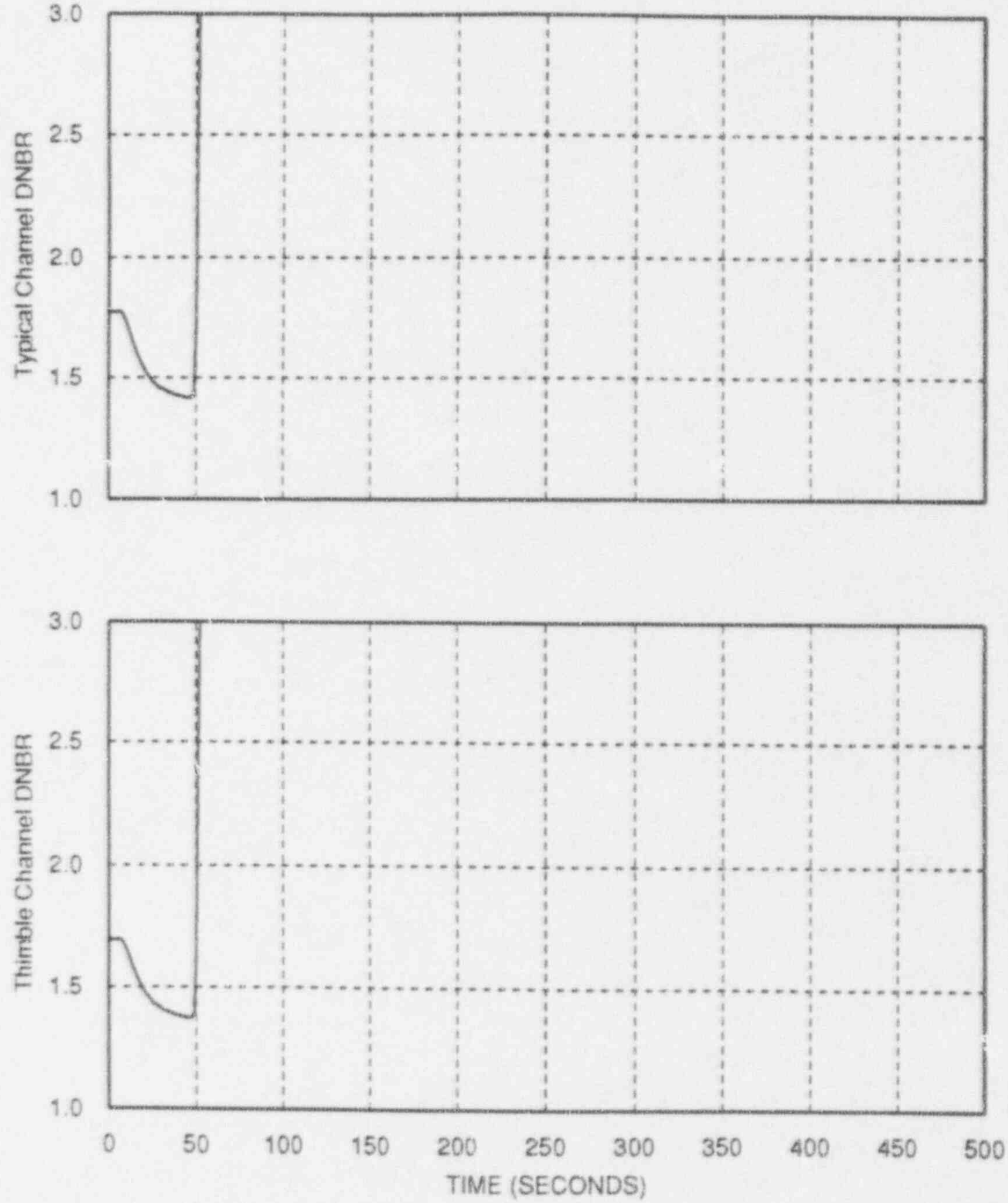
SEABROOK STATION	10% Step Load Increase Most Positive MTC Manual Rod Control FIGURE 5.1-2 , Sh. 2



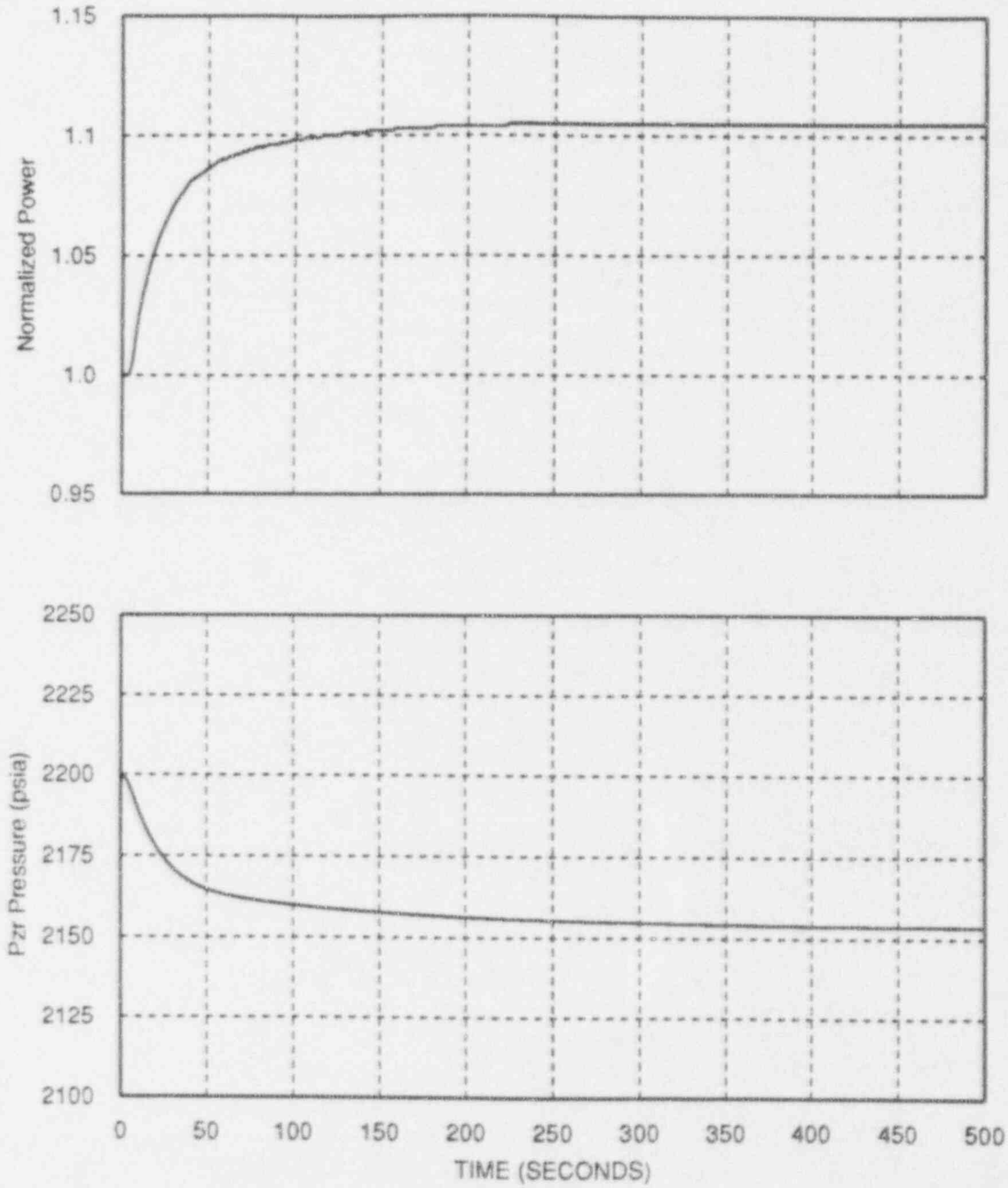
SEABROOK STATION	10% Step Load Increase Most Positive MTC Manual Rod Control FIGURE 5.1-2 , Sh. 3



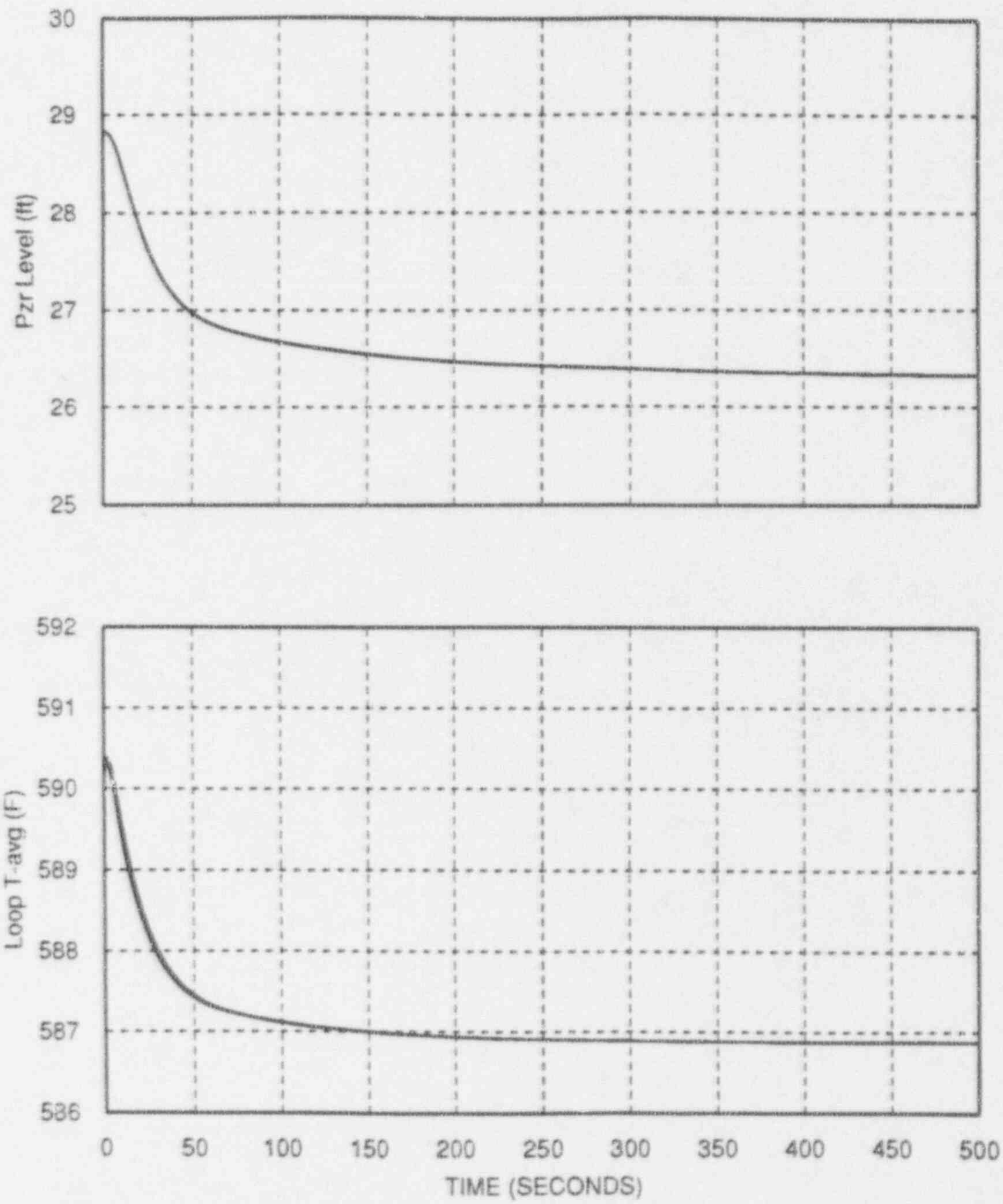
SEABROOK STATION	10% Step Load Increase Most Positive MTC Manual Rod Control FIGURE 5.1-2 , Sh. 4



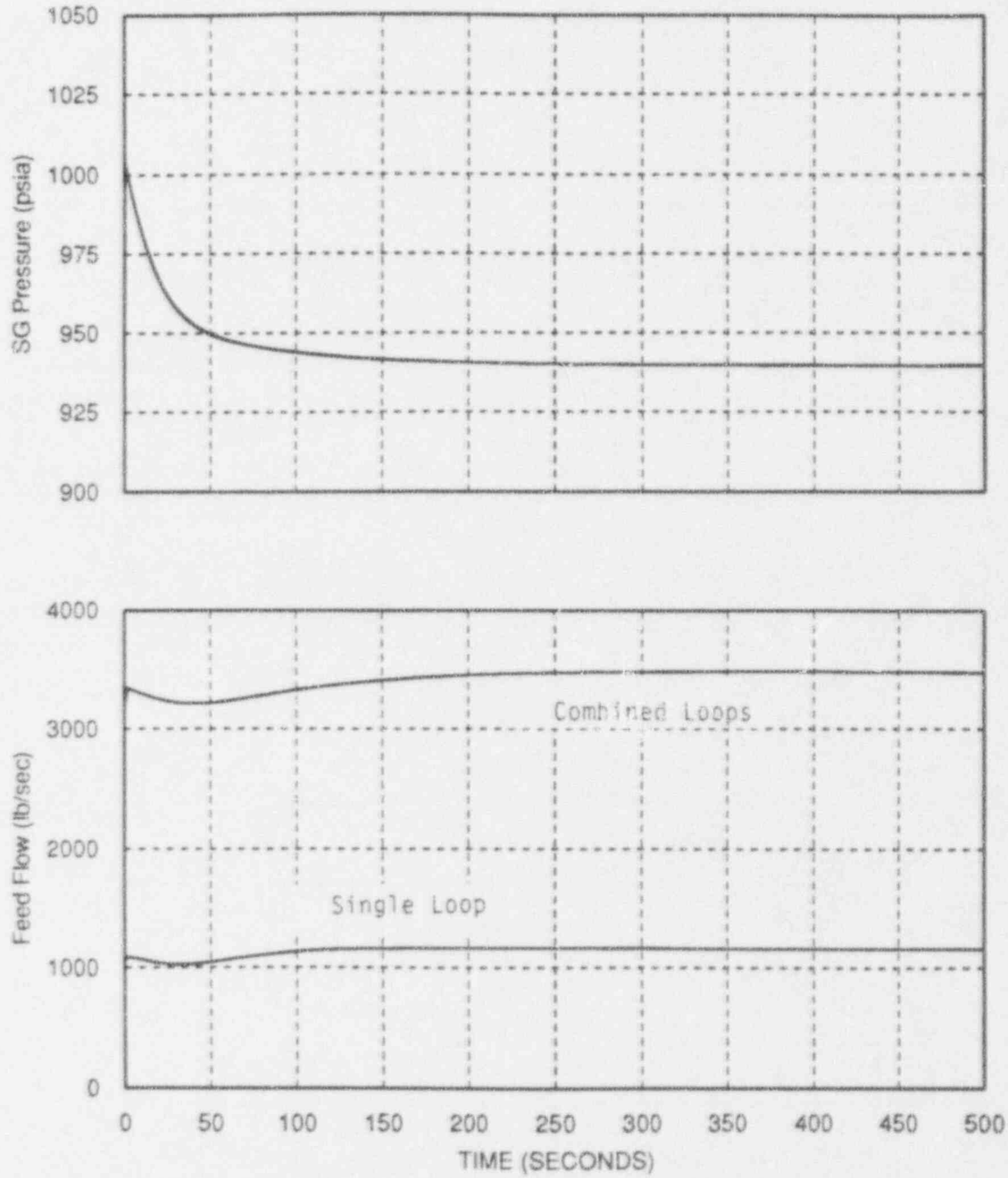
SEABROOK STATION	10% Step Load Increase Most Positive MTC Manual Rod Control FIGURE 5.1-2, Sh. 5



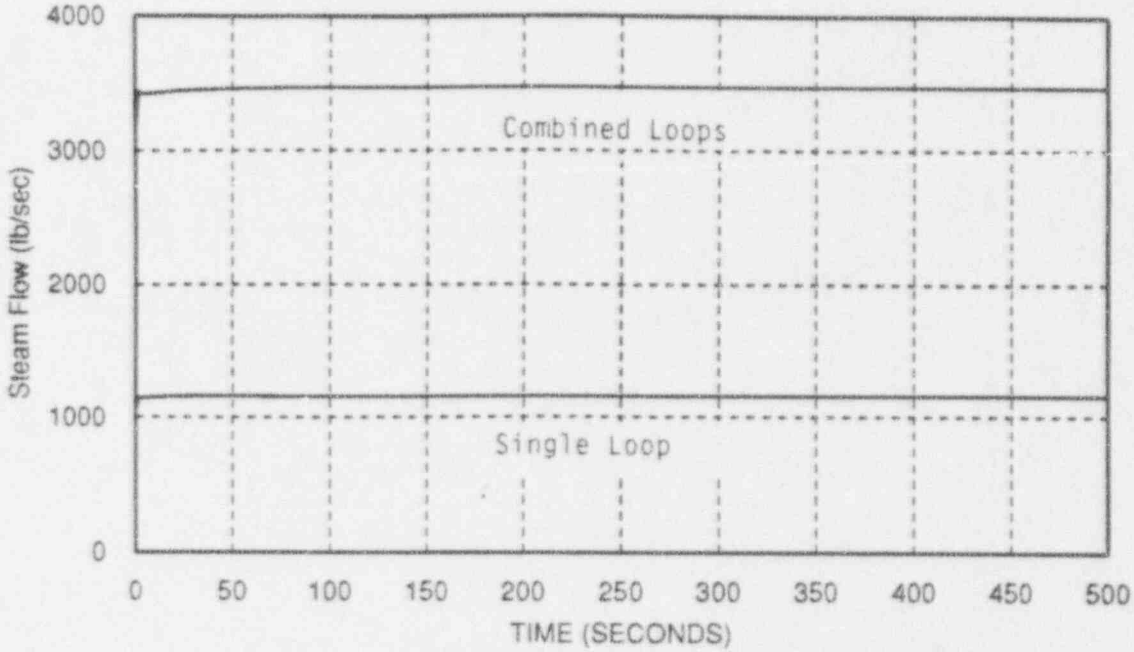
SEABROOK STATION	10% Step Load Increase Most Negative MTC Manual Rod Control FIGURE 5.1-3 , Sh. 1



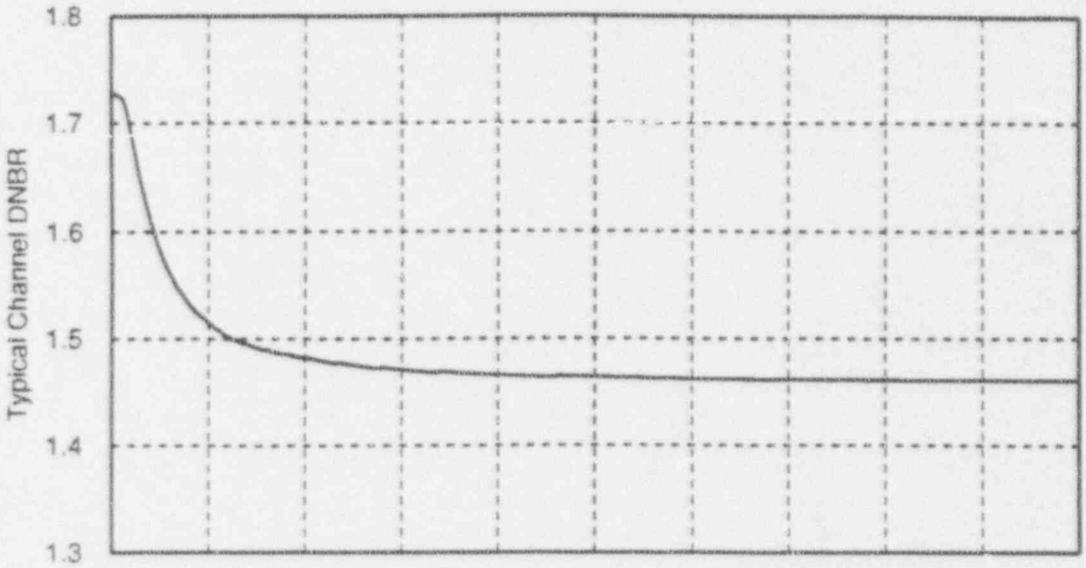
SEABROOK STATION	10% Step Load Increase Most Negative MTC Manual Rod Control
	FIGURE 5.1-3 , Sh. 2

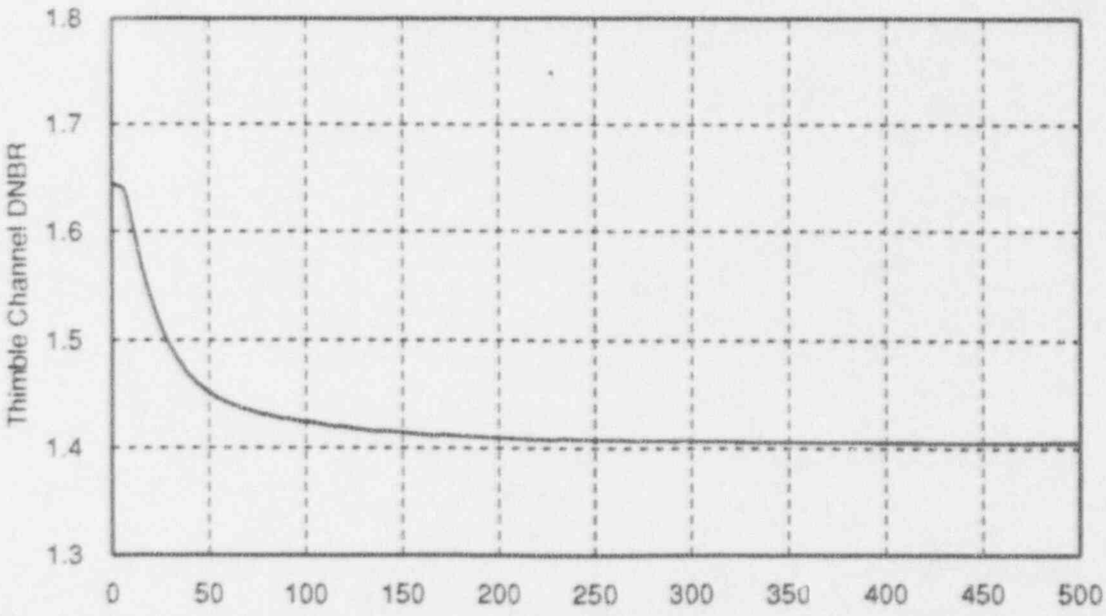


SEABROOK STATION	10% Step Load Increase Most Negative MTC Manual Rod Control FIGURE 5.1-3 , Sh. 3

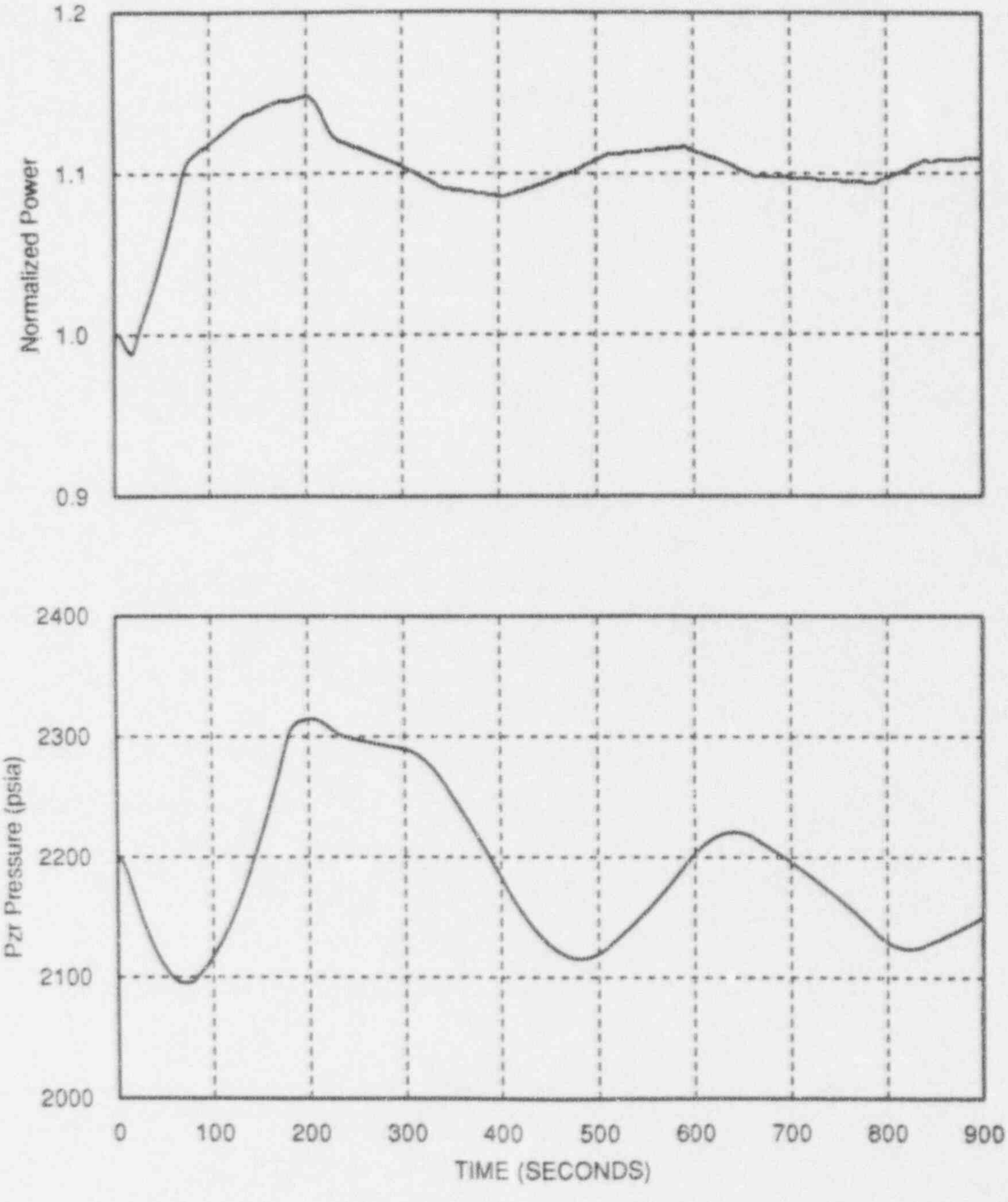


SEABROOK STATION	10% Step Load Increase Most Negative MTC Manual Rod Control FIGURE 5.1-3 , Sh. 4

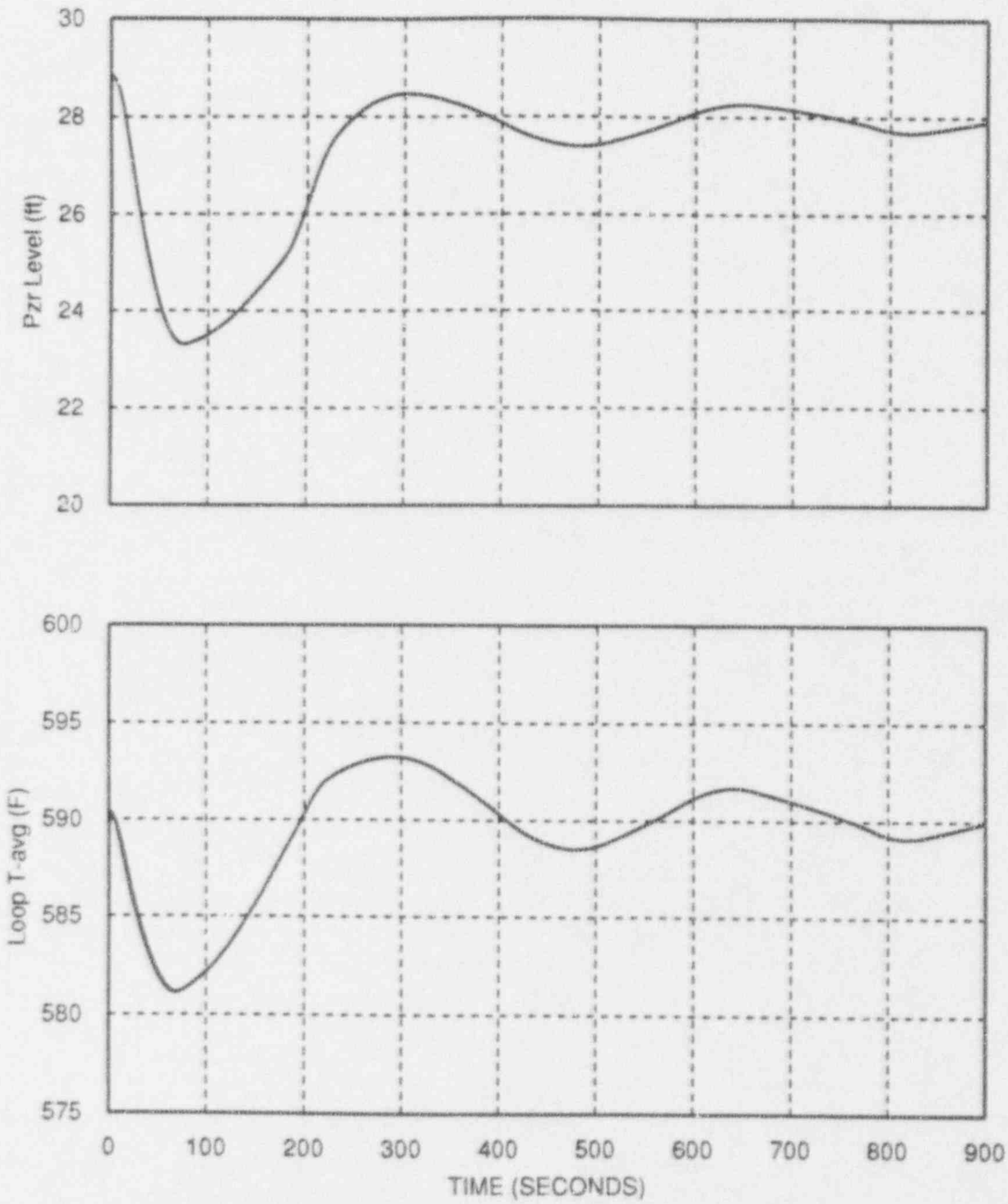




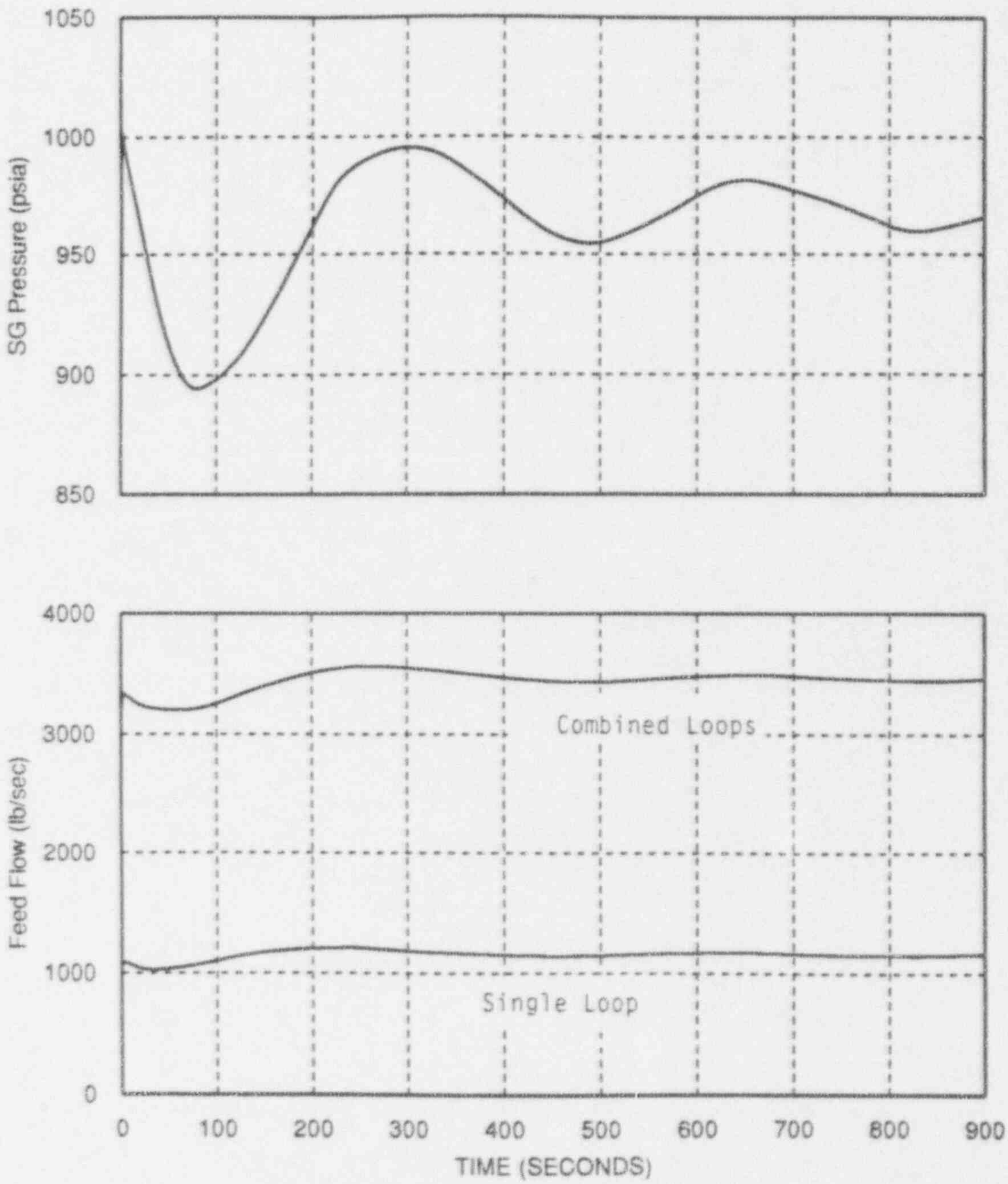
SEABROOK STATION	10% Step Load Increase Most Negative MTC Manual Rod Control FIGURE 5.1-3, Sh. 5



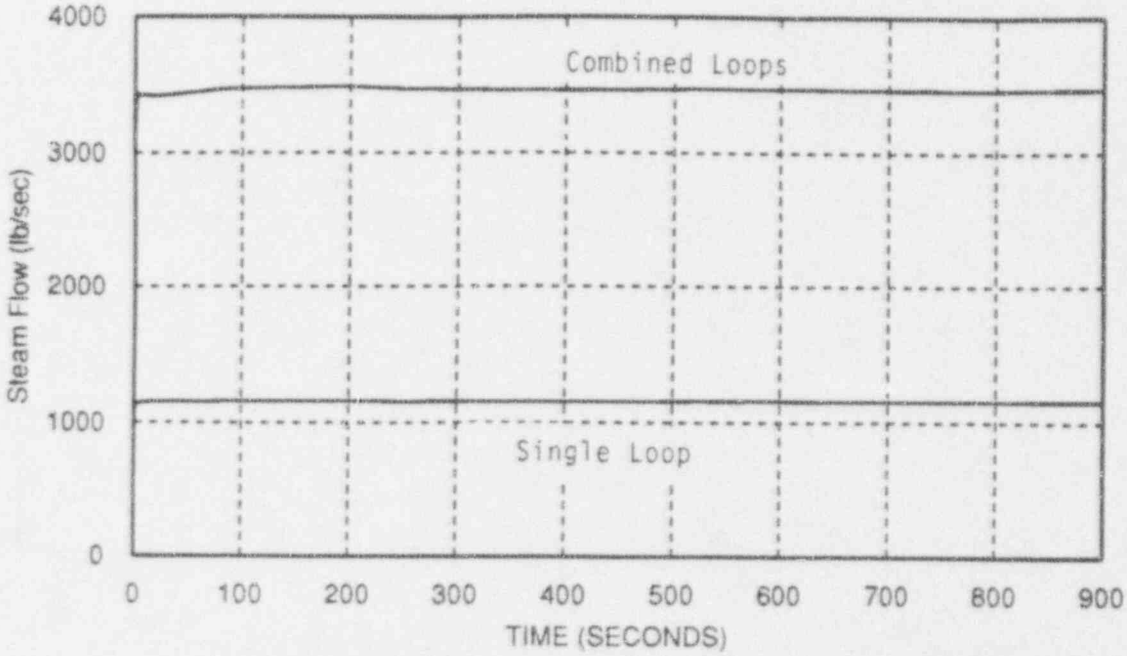
SEABROOK STATION	10% Step Load Increase Most Positive MTC Automatic Rod Control FIGURE 5.1-4 , Sh. 1



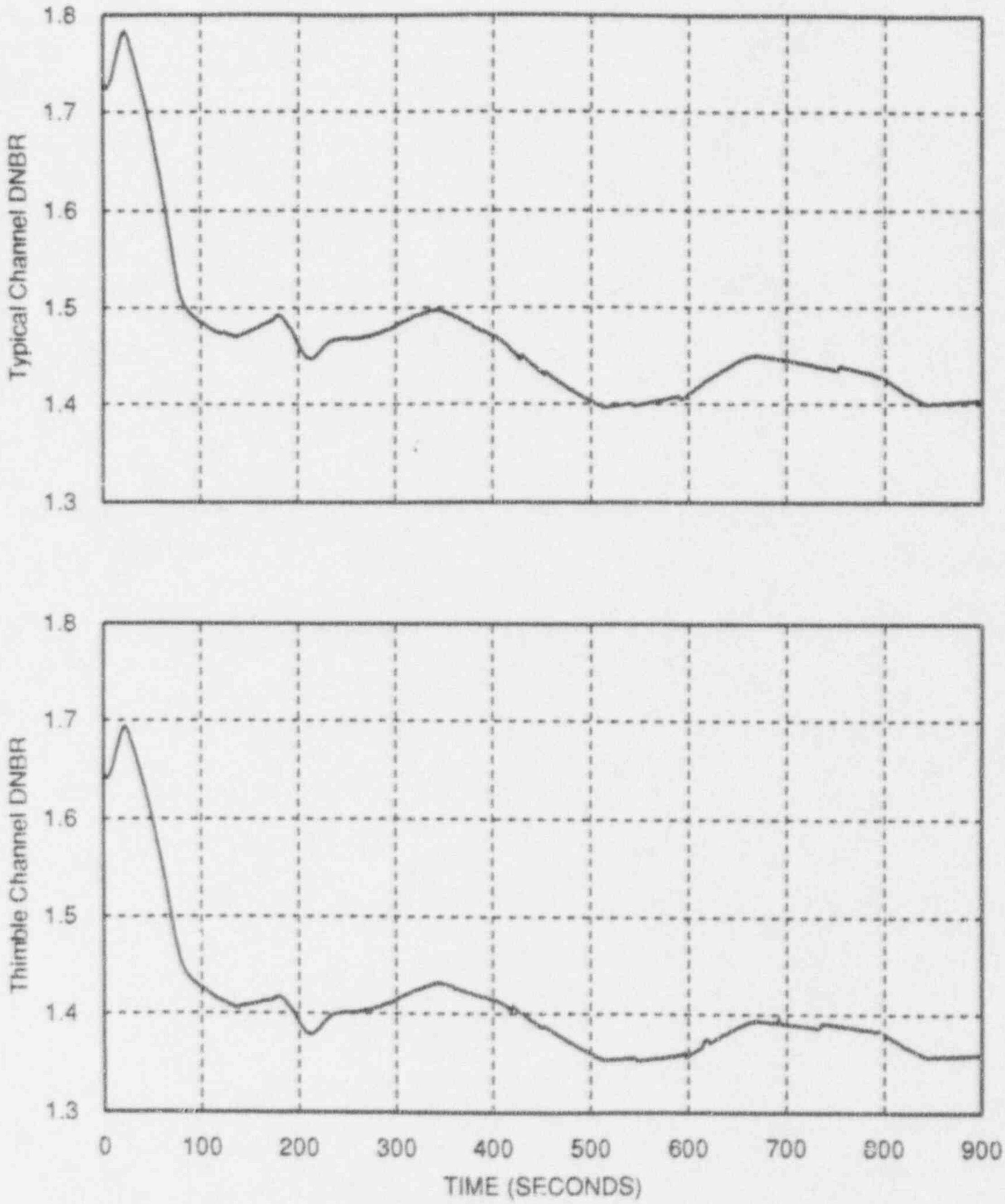
SEABROOK STATION	10% Step Load Increase Most Positive MTC Automatic Rod Control FIGURE 5.1-4 , Sh. 2



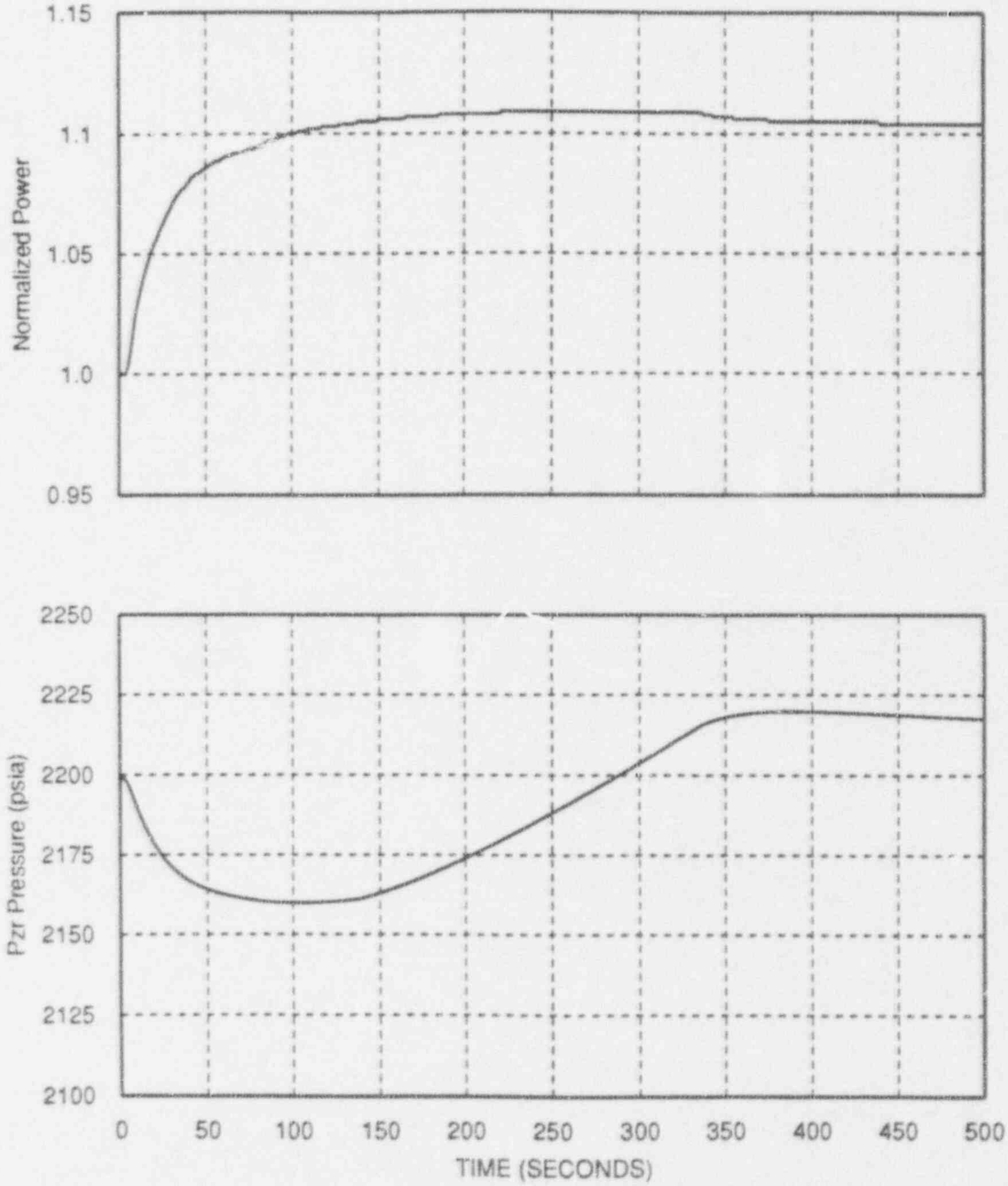
SEABROOK STATION	10% Step Load Increase Most Positive MTC Automatic Rod Control FIGURE 5.1-4 , Sh. 3



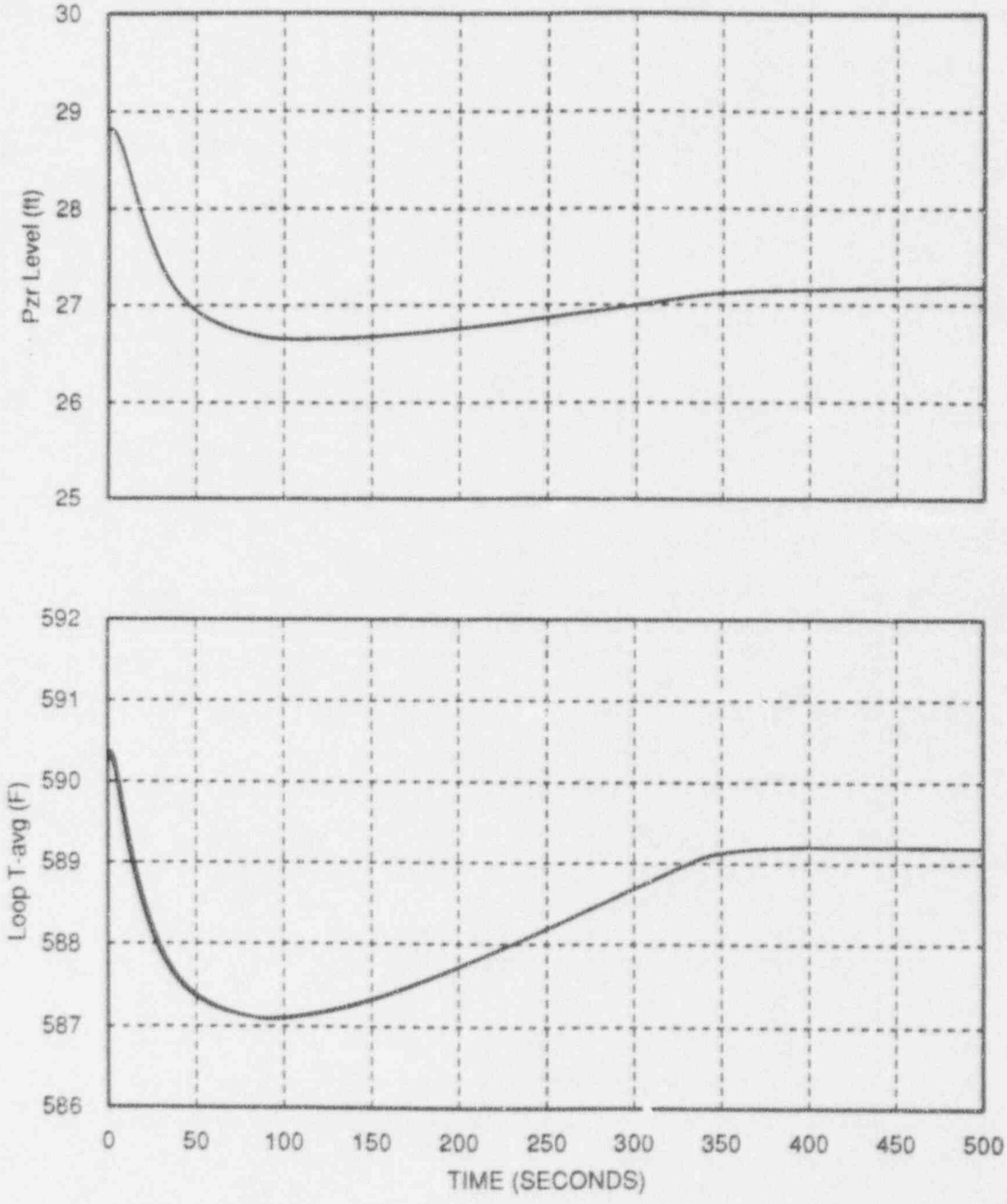
SEABROOK STATION	10% Step Load Increase Most Positive MTC Automatic Rod Control FIGURE 5.1-4 , Sh. 4



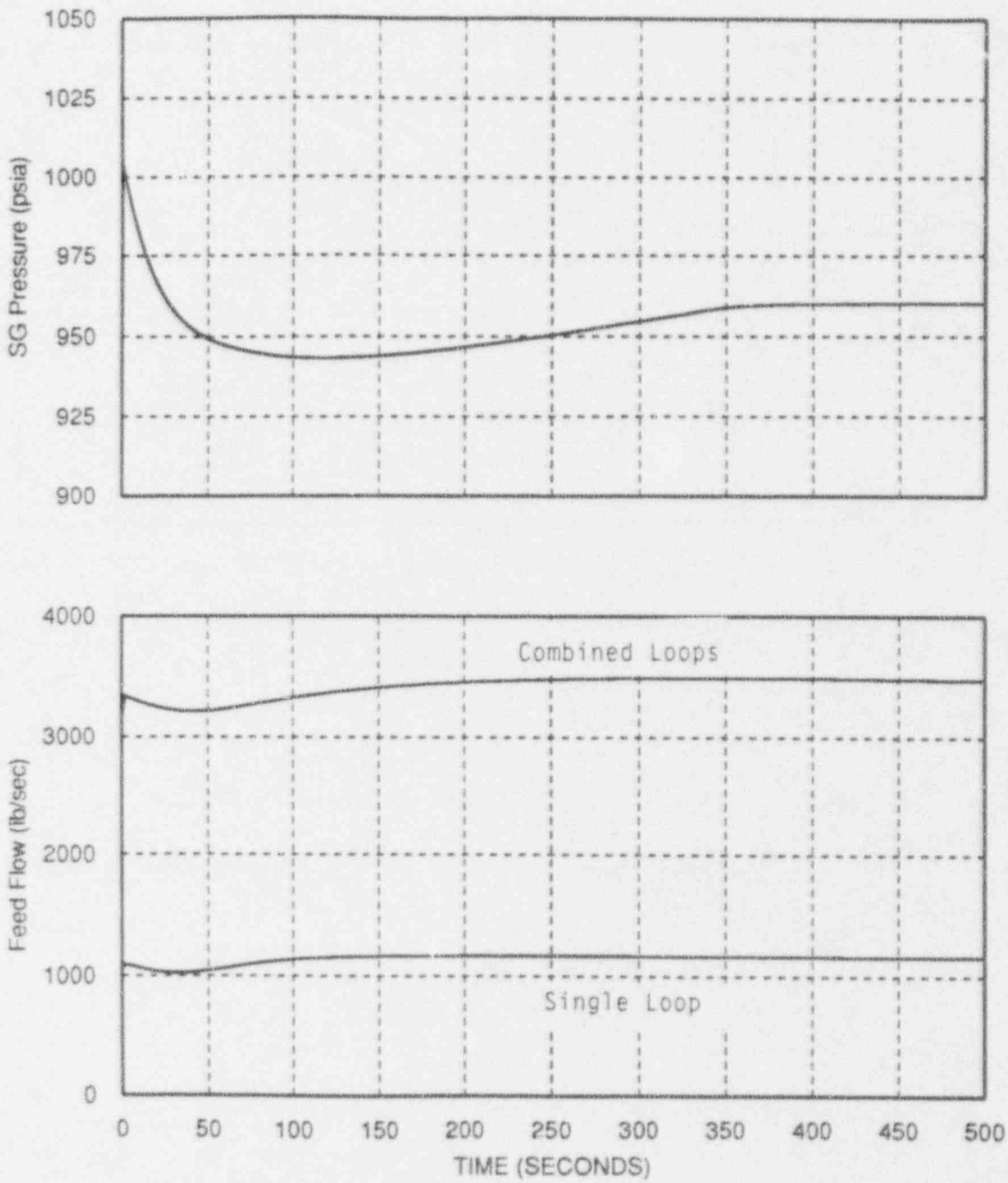
SEABROOK STATION	10% Step Load Increase Most Positive MTC Automatic Rod Control FIGURE 5.1-4, Sh. 5



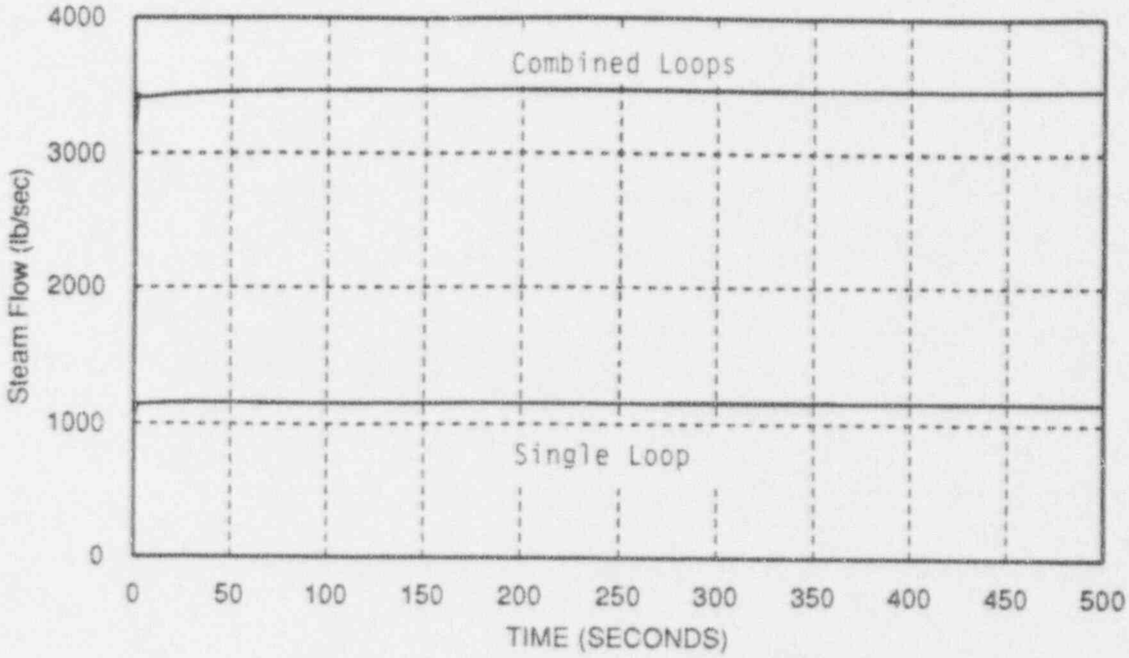
SEABROOK STATION	10% Step Load Increase Most Negative MTC Automatic Rod Control FIGURE 5.1-5 , Sh. 1



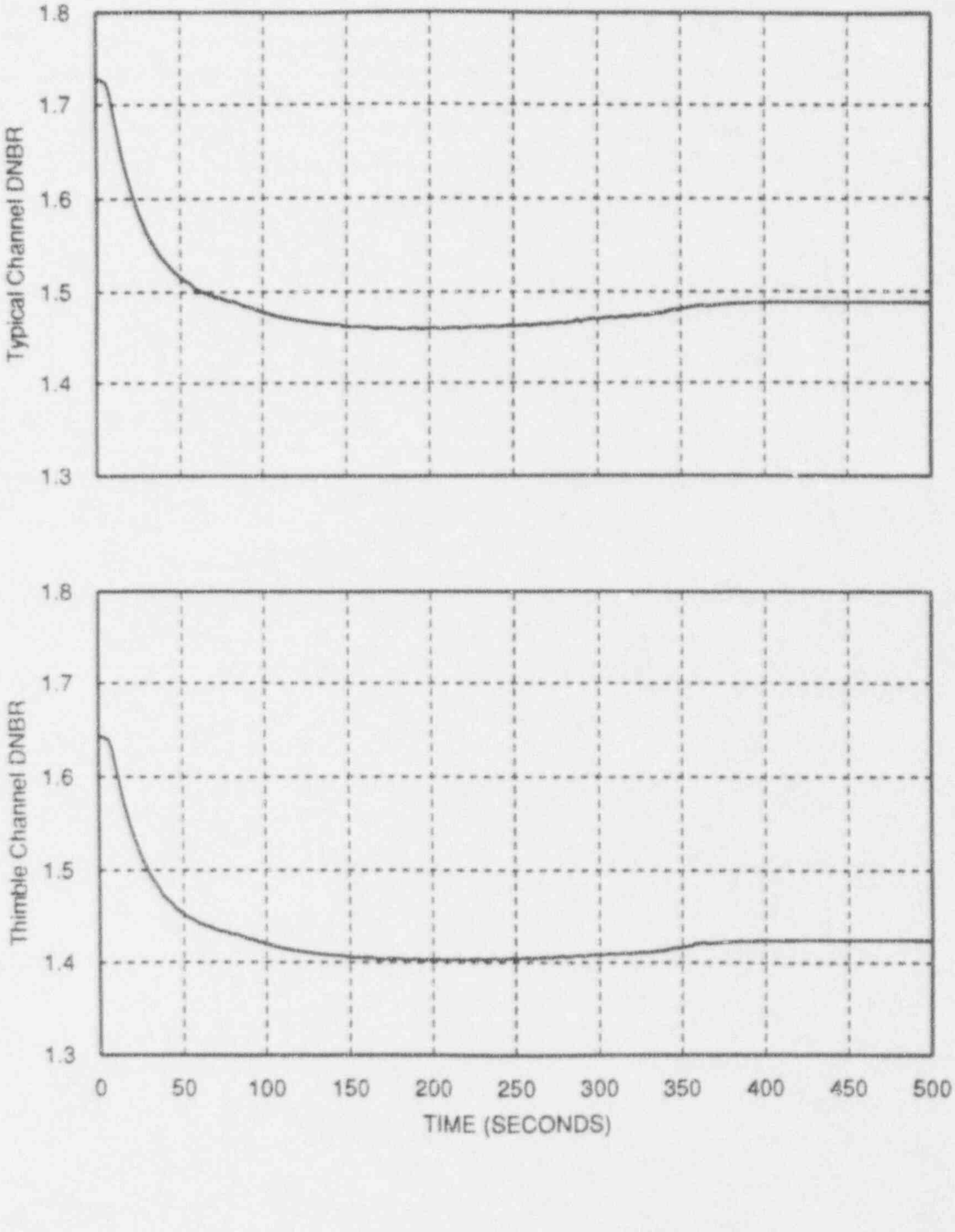
SEABROOK STATION	10% Step Load Increase Most Negative MTC Automatic Rod Control FIGURE 5.1-5 , Sh. 2



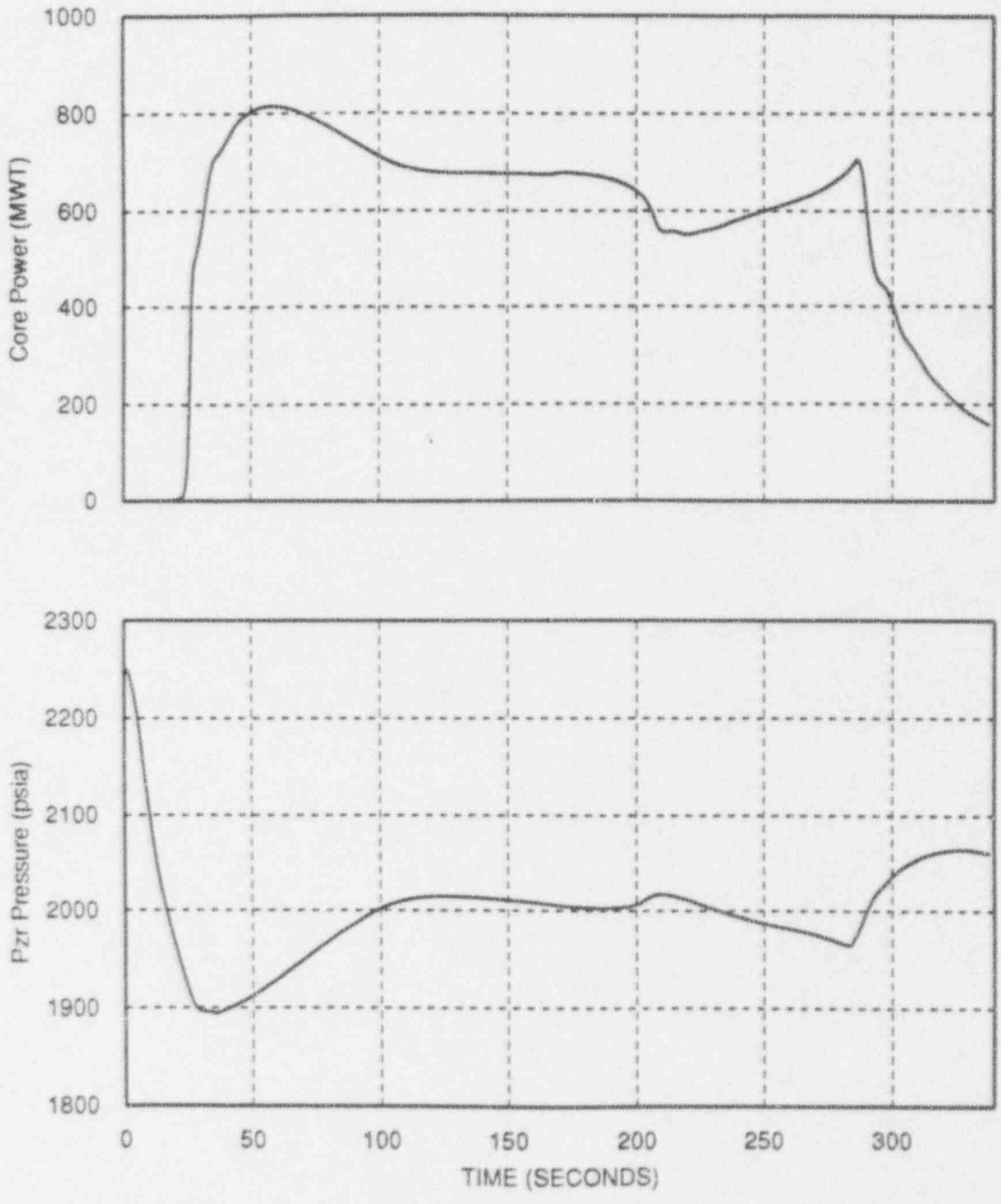
SEABROOK STATION	10% Step Load Increase Most Negative MTC Automatic Rod Control FIGURE 5.1-5 , Sh. 3



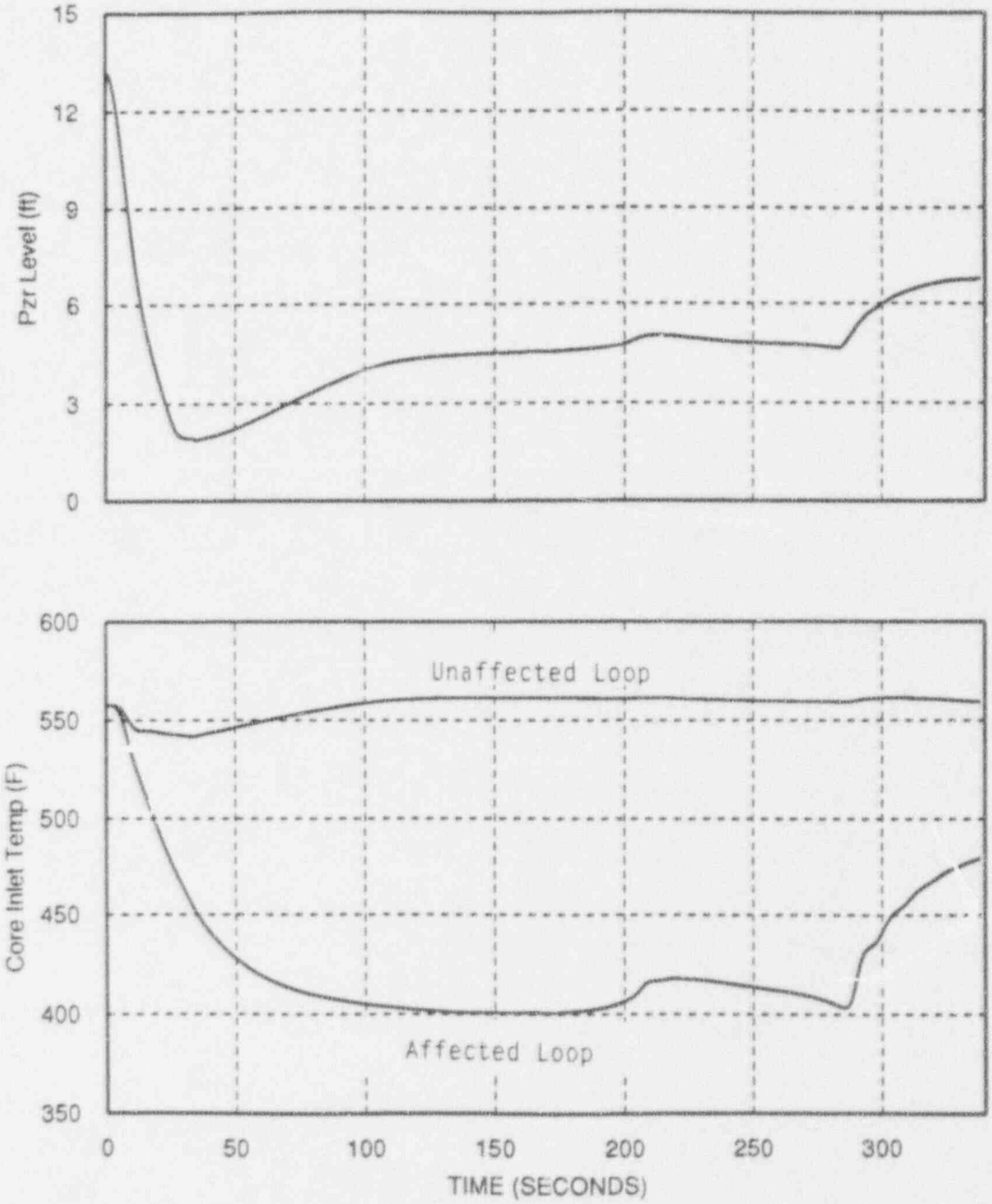
SEABROOK STATION	10% Step Load Increase Most Negative MTC Automatic Rod Control FIGURE 5.1-5 , Sh. 4



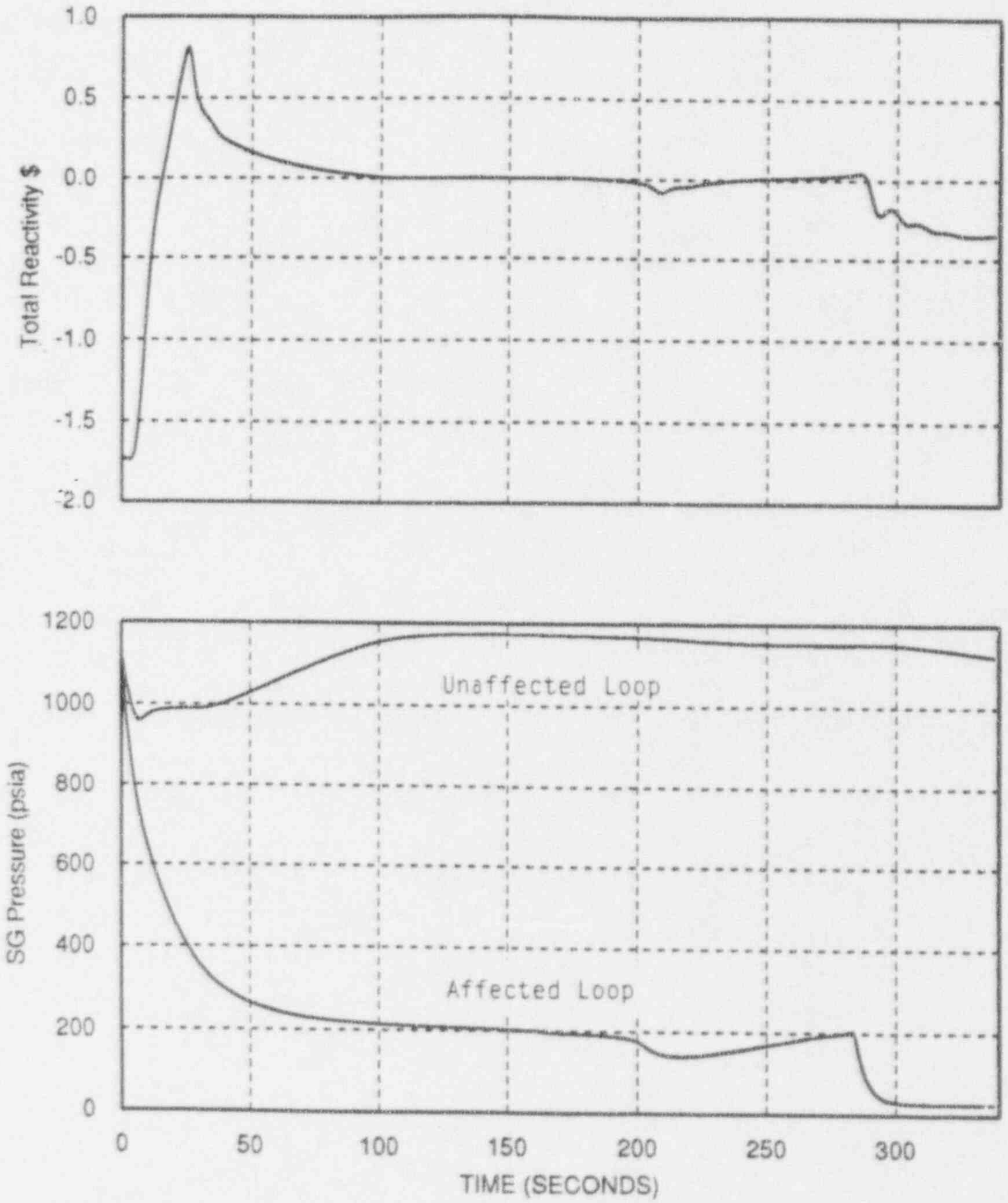
SEABROOK STATION	10% Step Load Increase Most Negative MTC Automatic Rod Control FIGURE 5.1-5, Sh. 5



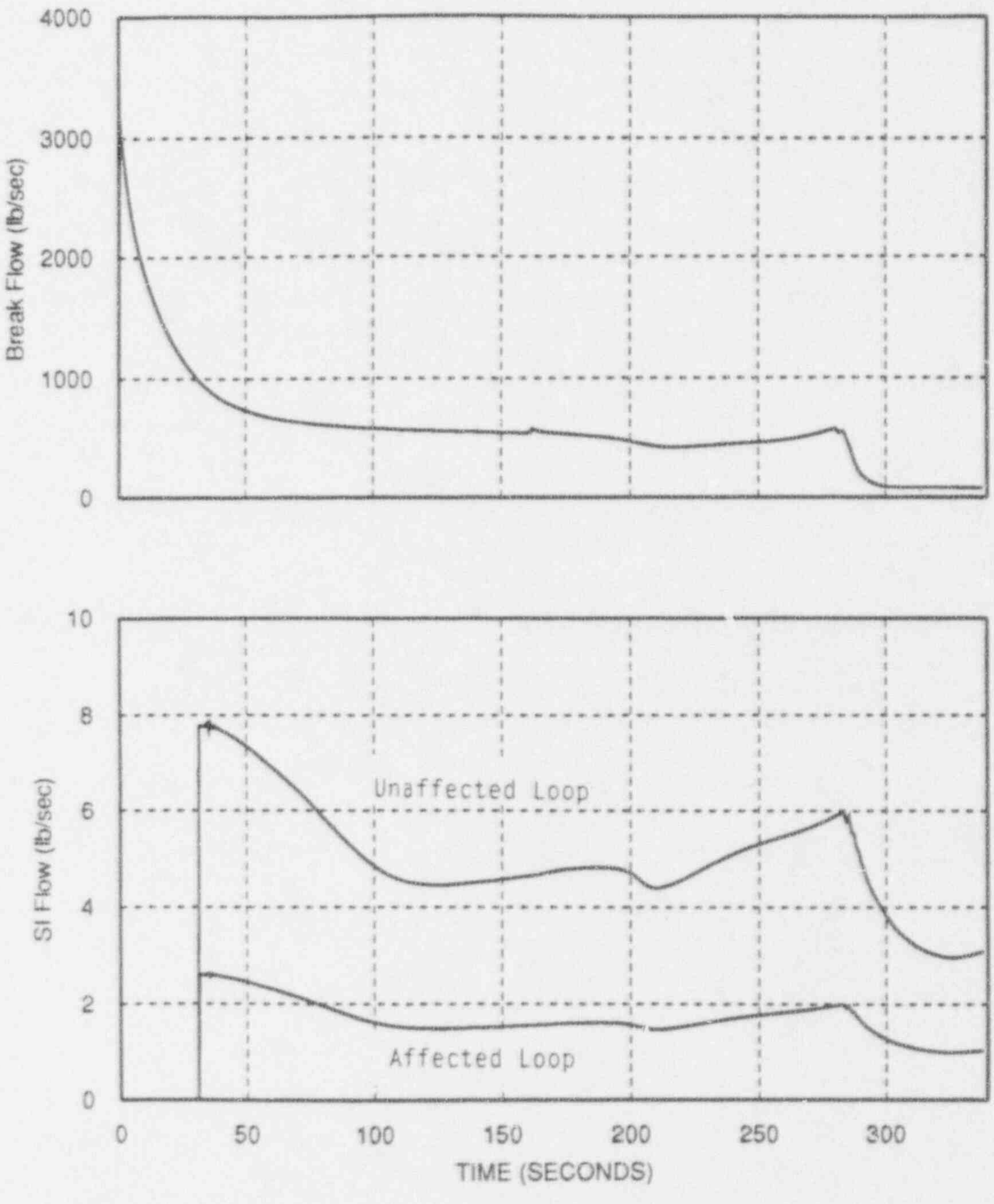
SEABROOK STATION	Main Steam Line Rupture at Zero Power With Offsite Power Available FIGURE 5.1-6 , Sh. 1



SEABROOK STATION	Main Steam Line Rupture at Zero Power With Offsite Power Available FIGURE 5.1-6 , Sh. 2



SEABROOK STATION	Main Steam Line Rupture at Zero Power With Offsite Power Available FIGURE 5.1-6 , Sh. 3



SEABROOK STATION	Main Steam Line Rupture at Zero Power With Offsite Power Available FIGURE 5.1-6 , Sh. 4

5.2 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

A number of transients and accidents have been postulated in this section which could result in a reduction of the capacity of the secondary system to remove heat generated in the Reactor Coolant System (RCS). Detailed analyses are presented for the most limiting of these events.

Discussions of the following RCS coolant heatup events are presented in this section:

a. Steam pressure regulator malfunction

b. Loss of external load

c. Turbine trip

d. Inadvertent closure of main steam isolation valves

e. Loss of condenser vacuum and other events resulting in turbine trip

f. Loss of nonemergency AC power to the station auxiliaries

g. Loss of normal feedwater flow

h. Feedwater system pipe break.

The above items are considered to be American Nuclear Society (ANS) Condition II events, with the exception of a feedwater system pipe break, which is considered to be an ANS Condition IV event. Events c, f, g, and h were reanalyzed and results are presented in this section. Event a is not applicable to Seabrook Station; events b,d, and e are bounded by event c.

5.2.1 Steam Pressure Regulator Malfunction Or Failure that Results In Decreasing Steam Flow

There are no steam pressure regulators in the Seabrook plant whose failure or malfunction could cause a steam flow transient.

5.2.2 Loss of External Load

A loss of external load event results in a nuclear steam supply system transient that is less severe than a turbine trip event (see Subsection 5.2.3). Therefore, a detailed transient analysis is not presented for the loss of external load. The radiological consequences resulting from this malfunction are considerably less than those calculated for a main steam line rupture. The analyses performed assuming a rupture of a main steam line are given in Subsection 5.1.5.

5.2.3 Turbine Trip

5.2.3.1 Identification of Causes and Accident Description

For a turbine trip event, the reactor would be tripped directly (unless below the P-9 setpoint) from a signal derived from the turbine emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly (typically 0.1 seconds) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. Turbine trip initiation signals include:

a. Electrical faults associated with the generator or transformers
b. Low condenser vacuum
c. Loss of lubricating oil
d. Turbine thrust bearing failure
e. Turbine overspeed
f. Main steam reheat high level
g. Manual trip.

Upon initiation of stop valve closure, steam flow to the turbine stops abruptly. Sensors on the stop valves detect the turbine trip and initiate steam dump and, if above the P-9 setpoint, a reactor trip. The loss of steam flow results in an almost immediate rise in secondary system temperature and pressure, with a resultant primary system transient similar to the loss of external load event. A slightly more severe transient occurs for the turbine trip event due to the more rapid loss of steam flow caused by the more rapid valve closure.

The automatic Steam Dump System would normally accommodate the excess steam generation when the unit is operating below the P-9 setpoint. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere and main

feedwater flow would be lost. For this situation, feedwater flow would be maintained by the Emergency Feedwater System to ensure adequate residual and decay heat removal capability. Should the Steam Dump System fail to operate, the steam generator safety valves may lift to provide pressure control.

A turbine trip is classified as an ANS Condition II event, a fault of moderate frequency.

A turbine trip event is more limiting than loss of external load, loss of condenser vacuum, and other turbine trip events. As such, this event has been analyzed in detail. Results and discussion of the analysis are presented in Subsection 5.2.3.2.

5.2.3.2 Analysis of Effects and Consequences

a. Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 102 percent of full power without direct reactor trip, primarily to show the adequacy of the pressure relieving devices and also to demonstrate core protection margins. The turbine is assumed to trip without actuating any of the sensors for reactor trip on the turbine stop valves. This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for emergency feedwater to mitigate the consequences of the transient.

The turbine trip transients are analyzed by employing the detailed digital computer program RETRAN[9]. The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Major assumptions are summarized below:

1. Initial Operating Conditions - The initial reactor power and RCS temperatures are assumed at their maximum values consistent with steady-state full power operation including allowances for calibration and instrument errors. The initial RCS pressure is assumed at a minimum value consistent with steady-state full power operation including allowances for calibration and instrument

errors. This results in the maximum power difference for the load loss, and the minimum margin to core protection limits at the initiation of the accident.

2. Reactivity Coefficients - Two cases are analyzed:

   (a) Minimum reactivity feedback

   A most positive MTC and a least negative Doppler-only power coefficient are assumed.

   (b) Maximum reactivity feedback

   A conservatively large negative moderator temperature coefficient and a most negative Doopler-only power coefficient are assumed.

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

4. Steam Release - No credit is taken for the operation of the Steam Dump System or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

5. Pressurizer Spray and Power-Operated Relief Valves - Two cases for both the minimum and maximum moderator feedback cases are analyzed:

   (a) Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Pressurizer safety valves are also available.

   (b) No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Pressurizer safety valves are operable.

6. Feedwater Flow - Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for emergency feedwater

flow since a stabilized plant condition will be reached before emergency feedwater initiation is normally assumed to occur; however, the emergency feedwater pumps would be expected to start on a trip of the main feedwater pumps. The emergency feedwater flow would remove core decay heat following plant stabilization.

7. Reactor trip is actuated by the first reactor protection system trip setpoint reached, with no credit taken for the direct reactor trip on the turbine trip. Trip signals are expected due to high pressurizer pressure, Overtemperature ΔT, and low-low steam generator water level.

Except as discussed above, normal Reactor Control Systems and Engineered Safety Systems are not required to function. Several cases are presented in which pressurizer spray and power-operated relief valves are assumed, but the more limiting cases where these functions are not assumed are also presented.

The Reactor Protection System may be required to function following a turbine trip. Pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure will prevent operation of any system required to function.

b. <u>Results</u>

The transient responses for a turbine trip from 102 percent of full power operation are shown for four cases: two cases for minimum reactivity feedback and two cases for maximum reactivity feedback (Figures 5.2-1 through 5.2-4). The calculated sequence of events for the accident is shown in Table 5.2-1.

Figure 5.2-1 shows the transient responses for the total loss of steam load with minimum reactivity feedback assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel. The minimum DNBR remains well above the safety analysis limit value. The pressurizer safety valves are actuated briefly for this case. The steam generator safety valves limit the secondary steam conditions to saturation at the safety valve setpoint pressure.

Figure 5.2-2 shows the responses for the total loss of steam load with maximum reactivity feedback. All other plant parameters are the same as above. The reactor is tripped

by high pressurizer pressure. The rise in RCS average temperature causes a large reduction in neutron flux due to reactivity feedback effects prior to the trip on high pressurizer pressure. The DNBR remains above the safety analysis limit throughout the transient. The pressurizer safety valves are not actuated for this case.

The turbine trip accident was also studied assuming the plant to be initially operating at 102 percent of full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figure 5.2-3 shows the transients with minimum reactivity feedback. The power increases slightly prior to the trip on high pressurizer pressure due to the positive MTC. The DNBR remains above the safety analysis limit throughout the transient. In this case the pressurizer safety valves are actuated, and maintain system pressure below 110 percent of the design value.

Figure 5.2-4 shows the transients with maximum reactivity feedback with the other assumptions being the same as in the preceding case. Again, the DNBR remains above the safety analysis limit throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

5.2.3.3 Radiological Consequences

The radiological consequences resulting from this event are considerably less than those calculated for a main steam line rupture. The analyses performed assuming a rupture of a main steam line are given in Subsection 5.1.5.

5.2.3.4 Conclusions

Results of the analyses show that the plant design is such that a turbine trip without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. Pressure relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The integrity of the core is maintained by operation of the Reactor Protection System, i.e., the DNBR will be maintained above the safety analysis limit value. The above analysis demonstrates the ability of the Nuclear Steam Supply System to safely withstand a full load rejection.

5.2.4 Inadvertent Closure of Main Steam Isolation Valves

Inadvertent closure of the main steam isolation valves would result in a turbine trip. Turbine trips are discussed in Subsection 5.2.3.

5.2.5 Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip

A turbine trip due to loss of condenser vacuum does not entail more adverse effects than the general turbine trip accident analyzed in detail in Subsection 5.2.3, because in that analysis no credit is taken for condenser steam dump. Therefore, the analysis results and conclusions of Subsection 5.2.3 apply to the loss of condenser vacuum.

5.2.6 Loss of Nonemergency AC Power to The Plant Auxiliaries (Loss of Offsite Power)

5.2.6.1 Identification of Causes and Accident Description

A complete loss of nonemergency AC power may result in the loss of all power to the station auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the plant, or by a loss of the onsite AC distribution system.

For this event the decrease in heat removal by the secondary system is accompanied by a flow coastdown which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip: (1) due to turbine trip; (2) upon reaching one of the trip setpoints in the primary and secondary systems as a result of the flow coastdown and decrease in secondary heat removal; or (3) due to loss of power to the control rod drive mechanisms as a result of the loss of power to the plant.

Following a loss of AC power with turbine and reactor trips, the sequence described below will occur:

a. Plant vital instruments are supplied from emergency DC power sources.

b. As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the power-operated relief valves are not available, the steam generator self-actuated

safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

c. As the no-load temperature is approached, the steam generator power-operated relief valves (or the safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition.

d. The emergency diesel generators, started on loss of voltage on the plant emergency buses, begin to supply plant emergency loads.

The Emergency Feedwater System is started automatically as described below.

Both the motor-driven emergency feedwater pump and the turbine-driven emergency feedwater pump are started on any of the following:

a. Low-low level in any steam generator
b. Any safety injection signal
c. Manual actuation.

The motor-driven emergency feedwater pump is supplied power from one of the ESF buses. The turbine-driven emergency feedwater pump is driven by steam from the secondary system and exhausts to the atmosphere. Both types of pumps are designed to start and supply rated flow within 75 seconds of the initiating signal. The emergency pumps take suction from the condensate storage tank for delivery to the steam generators.

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.

A loss of nonemergency AC power to the station auxiliaries is classified as an ANS Condition II event, a fault of moderate frequency.

A loss of AC power event is a more limiting event than the turbine trip initiated decrease in secondary heat removal without loss of AC power, which was analyzed in Subsection 5.2.3. A loss of AC power to the station auxiliaries as postulated above could also result in a loss of normal feedwater if the condensate pumps lose their power supply.

Following the reactor coolant pump coastdown caused by the loss of AC power, the natural circulation capability of the RCS will remove residual and decay heat from the core, aided by emergency feedwater in the secondary system. An analysis is presented below to show that the natural circulation flow in the RCS following a loss of AC power event is sufficient to remove residual heat from the core.

The loss of nonemergency AC power and the resulting loss of feedwater occurs at the start of the transient. However, the reactor trip and loss of RCS flow, which would normally occur, is not assumed to happen at this time. This causes the primary side coolant to heat up and the steam generator inventory to decrease. The reactor is finally tripped on a low-low steam generator level signal, and at this time, the loss of primary flow due to the loss of AC is assumed to occur.

The above assumptions are more conservative than an actual loss of nonemergency AC because the reactor power is maintained following the loss of AC and loss of feedwater. This minimizes the steam generator heat transfer capability and increases the amount of RCS stored energy at the time of reactor trip and loss of primary coolant flow.

5.2.6.2 Analysis of Effects and Consequences

a. Method of Analysis

A detailed analysis using the RETRAN Code[9] is performed to calculate the transient response of the Reactor Coolant System and to obtain the natural circulation flow following a loss of nonemergency AC. The simulation describes the plant neutron kinetics, RCS including natural circulation, pressurizer, steam generators and feedwater system. The program computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in the analysis are as follows:

1. The plant is initially operating at 102 percent of the Rated Thermal Power.

2. A conservative core residual heat generation based upon long- term operation at the initial power level preceding the trip.

3. A heat transfer coefficient in the steam generator associated with RCS natural circulation, following the reactor coolant pump coastdown.

4. Reactor trip occurs on steam generator low-low level. No credit is taken for immediate release of the control rod drive mechanisms caused by a loss of offsite power.

5. Emergency feedwater is delivered by only one emergency feed pump to four steam generators.

6. Secondary system steam relief is achieved through the steam generator safety valves.

7. The pressurizer relief valves are assumed not to function.

8. The initial reactor coolant average temperature is 5.8°F higher than the nominal value.

9. The most positive MTC is used for conservatism.

The assumptions used in the analysis are similar to the loss of normal feedwater flow incident (Subsection 5.2.7) except that power is assumed to be lost to the reactor coolant pumps at the time of reactor trip.

The RCS flow coastdown subsequent to the loss of nonemergency AC is accomplished by tripping the RCPs in the RETRAN calculation. The resulting flow coastdown includes the effects of momentum around the reactor coolant loops and the pump characteristics. The flow coastdown is consistent with that assumed in the complete loss of flow transient discussed in Section 5.3.2. The flow coastdown in the RETRAN model has been verified against plant data[9].

The steam generator heat transfer coefficient is computed as a function of primary flow, heat flux, and secondary side conditions.

Natural circulation flow calculations are based primarily on heat generation, heat removal, and elevation (density) head. The effect of pressure losses and fluid momentum are also considered.

b. Results

The transient responses of the RCS and the secondary side following a loss of nonemergency AC power are shown in Figure 5.2-5.

The first few seconds after the loss of power to the reactor coolant pumps will closely resemble a simulation of the complete loss of flow incident (see Subsection 5.3.2), i.e., core damage due to rapidly increasing core temperatures is prevented by promptly tripping the reactor. After the reactor trip, stored and residual decay heat must be removed to prevent damage to either the RCS or the core.

Natural circulation flow is available and is sufficient to provide adequate core decay heat removal following reactor trip and reactor coolant pump coastdown.

Since DNBR does not fall below the limit value, no fuel or clad damage occurs. The calculated sequence of events for this accident is listed in Table 5.2-1.

5.2.6.3 Radiological Consequences

The radiological consequences resulting from this malfunction are considerably less than those calculated for a main steam line rupture. The analyses performed assuming a rupture of a main steam line are given in Subsection 5.1.5.

5.2.6.4 Conclusions

Analysis of the natural circulation capability of the RCS has demonstrated that sufficient heat removal capability exists following reactor coolant pump coastdown to prevent fuel or clad damage. The radiological consequences of this event would be less severe than the steam line break event analyzed in Subsection 5.1.5.

5.2.7 Loss of Normal Feedwater Flow

5.2.7.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater were not supplied to the plant, core residual heat following reactor trip 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 RCS. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

The following events occur upon loss of normal feedwater (assuming main feedwater pump failures or valve malfunctions):

a. As the steam system pressure rises following the trip, the steam generator power-operated relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the steam flow rate through the power-operated relief valves is not adequate, the steam generator self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

b. As the no-load temperature is approached, the steam generator power-operated relief valves (or the safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition.

A loss of normal feedwater is classified as an ANS Condition II event, a fault of moderate frequency.

Reactor trip on low-low water level in any steam generator provides protection for a loss of normal feedwater.

The Emergency Feedwater System is started automatically as discussed in Subsection 5.2.6.1. The motor-driven emergency feedwater pump is supplied power from one of the ESF buses. The turbine-driven emergency feedwater pump is driven by steam from the secondary system and exhausts to the atmosphere. The pumps take suction directly from the condensate storage tank for delivery to the steam generators.

An analysis of the system transient is presented below to show that following a loss of normal feedwater, the Emergency Feedwater System is capable of removing the stored and residual heat, thus preventing either overpressurization of the RCS or loss of water from the reactor core, and returning the plant to a safe condition.

5.2.7.2 Analysis of Effects and Consequences

a. Method of Analysis

A detailed analysis using the RETRAN Code[9] is performed in order to obtain the plant transient following a loss of normal feedwater. The simulation describes the plant neutron kinetics, RCS, pressurizer, steam generators and feedwater system. The program computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

Assumptions made in the analysis are:

1. The plant is initially operating at 102 percent of the Rated Thermal Power.

2. A conservative core residual heat generation based upon long- term operation at the initial power level preceding the trip.

3. Reactor trip occurs on steam generator low-low level.

4. The worst single failure in the Emergency Feedwater System occurs (one of the two emergency feed pumps fails to start).

5. Emergency feedwater is delivered by one emergency feed pump to four steam generators.

6. Secondary system steam relief is achieved through the steam generator safety valves.

7. The pressurizer relief valves are assumed not to function.

8. The initial reactor coolant average temperature is 5.8°F higher than the nominal value.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the Reactor Protection and Engineered Safeguards Systems (e.g., the Emergency Feedwater System) in removing long-term decay heat and preventing excessive heatup of the RCS with possible resultant RCS overpressurization or loss of RCS water.

The assumptions used in the analysis are similar to the loss of AC power incident (Subsection 5.2.6) except that the reactor coolant pumps are assumed to continue to operate.

Normal reactor control systems are not required to function. The Reactor Protection System is required to function following a loss of normal feedwater as analyzed here. The Emergency Feedwater System is required to deliver a minimum emergency feedwater flow rate. No single active failure will prevent operation of any system required to function.

b. Results

Figure 5.2-6 shows the significant plant parameters following a loss of normal feedwater.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction in steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. Within 75 seconds following the initiation of the low-low level trip, the emergency feedwater pumps are automatically started, reducing the rate of water level decrease.

The capacity of the emergency feedwater pumps is such that the water level in the steam generators being fed does not recede below the lowest level at which sufficient heat transfer area is available to dissipate core residual heat without water relief from the RCS relief or safety valves. Figure 5.2-6 shows that at no time is there water relief from the pressurizer.

The calculated sequence of events for this accident is listed in Table 5.2-1.

As shown in Figure 5.2-6, the plant will slowly approach a stabilized condition at hot standby with emergency feedwater removing decay heat. The plant may be maintained at hot standby or further cooled through manual control of the emergency feed flow. The operating procedures would also call for operator action to control RCS boron concentration and pressurizer level using the CVCS and to maintain steam generator level through control of the Emergency Feedwater System. Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of ten minutes following reactor trip.

5.2.7.3 Radiological Consequences

The radiological consequences resulting from this malfunction are considerably less than those calculated for a main steam line rupture. The analyses performed assuming a rupture of a main steam line are given in Subsection 5.1.5.

5.2.7.4 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system since the emergency feedwater capacity is such that sufficient core heat removal is maintained, the RCS does not overpressurize, and water is not relieved from the pressurizer relief or safety valves. The radiological consequences of this event would be less severe than the steam line break accident analyzed in Subsection 5.1.5.

5.2.8 Feedwater System Pipe Break

5.2.8.1 Identification of Causes and Accident Description

This section discusses the design basis accident resulting from a major feedwater line break (FWLB). A double-ended rupture is postulated to occur in a feedwater line between the check valve and the steam generator. As a result, complete loss of main feedwater (MFW) through the break is assumed. Also, the emergency feedwater (EFW) to the faulted steam generator is assumed to be lost through the break. A break upstream of the feedwater line check valve would affect the Nuclear Steam Supply System only as a loss of feedwater. This case is covered by the evaluation in Subsections 5.2.6 and 5.2.7.

Depending upon the size of the break and the plant operating conditions, this event could cause either an RCS cooldown (by excessive discharge through the break) or an RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in Subsection 5.1.5. Therefore, only the RCS 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, to prevent overpressurization of the RCS and secondary systems and to prevent reactor core uncovery.

A major feedwater line rupture is classified as an ANS Condition IV event.

The following provides the protection for a main feedwater line rupture:

a. A reactor trip on any of the following conditions:

1. High pressurizer pressure
2. Overtemperature ΔT
3. Low-low steam generator water level in any steam generator
4. 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.

b. An Emergency Feedwater System to provide an assured source of feedwater to the steam generators for decay heat removal.

5.2.8.2 Analysis of Effects and Consequences

a. Method of Analysis

A detailed analysis using the RETRAN code[9] is performed in order to determine the plant transient following a feedwater line rupture. The code computes pertinent variables describing the resulting thermal hydraulics in the primary and secondary systems. These variables include pressurizer pressure, pressurizer water level, and reactor coolant temperatures.

Sensitivity studies in Reference 27 were previously performed to determine the worst-case initial conditions and assumptions which would maximize RCS heatup during the FWLB event. The worst-case FWLB scenario was determined to occur at full power with offsite power available. This was shown to be more conservative than the case without offsite power (RCP trip) because it evaluates the capability of the EFW to remove core decay heat as well as pump heat. Therefore, this worst-case scenario will be assumed in this analysis.

The other major assumptions are also formulated to maximize RCS heatup based on the findings of Reference 27. The analysis assumptions are as follows:

1. The plant is initially operating at 102% of the core thermal power rating.

2. Initial reactor coolant average temperature is 5.8 degrees F above the nominal value.

3. The initial pressurizer pressure is 50 psi above its nominal value.

4. Initial pressurizer water volume is at the nominal value plus 170 ft^3 uncertainty.

5. Initial steam generator water level is at the nominal value plus 5% in the faulted steam generator, and at the nominal value minus 5 percent in the intact steam generators.

6. A least negative Doppler reactivity coefficient is assumed, and moderator density reactivity is based on the most positive moderator temperature coefficient (MTC) in order to maximize reactor power prior to reactor trip.

7. No credit is taken for the pressure reducing effect of the pressurizer power-operated relief valves or pressurizer spray.

8. No credit is taken for normal charging and letdown.

9. A worst double-ended break is assumed downstream of the EFW connection in order to maximize break flow. This is done by obtaining choked conditions at the break. This assumption also results in spillage of all MFW to containment at the time of break initiation. By the same token, EFW to the faulted steam generator is assumed to completely spill.

10. Turbine trip is assumed at the time of break initiation and no credit is taken for the atmospheric steam dump valves.

11. Reactor trip and EFW actuation are credited on steam generator low-low level including the error due to harsh containment environment. A separate analysis was performed to conservatively minimize the steam generator mass at the low-low level setpoint in order to delay reactor trip.

12. Safety Injection Actuation is credited on low main steam line pressure.

13. Minimum high head ECCS pump performance and maximum ECCS temperature (100°F) are assumed. This corresponds to the case of conservatively assuming loss of one train with all the Centrifugal Charging Pump (CCP) and Safety Injection Pump (SIP) branch lines injecting to RCS backpressure (nonspillage condition).

14. EFW pump performance is based on loss of one train (single failure) and minimum design flow injected to the three intact steam generators by the operational pump. Cold EFW is assumed to not reach the steam generators until the three feedwater branch lines have been swept clear of hot feedwater.

b. Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures 5.2-7 through 5.2-10. The calculated sequence of events is listed in Table 5.2-1.

The response to the FWLB event is characterized by an RCS heatup prior to reactor trip followed by cooldown and then subsequent heatup due to MSIV closure, which terminates blowdown from the intact steam generators. The latter heatup lasts until the heat removal capacity of the EFW is sufficient to remove core decay heat and pump heat.

The RCS heatup prior to reactor trip is due to loss of subcooling as a result of MFW spillage through the break; and the increased secondary temperature and pressure following the turbine trip. Reactor power increases prior to the trip due to the RCS heatup and the assumed positive MTC. The primary and secondary system pressures quickly reached their respective safety valve setpoints. However, the peak pressures in the RCS 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 RCS and eventually causes the pressurizer to empty. However, the core remains covered with water. Low main steam line pressure causes closure of the MSIV's, ends the cooldown period, and starts safety injection. 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 MSIV closure and resulting increase in steam generator pressure and temperature cause the second RCS heatup. As a result, the rising primary system pressure exceeds the shutoff head of the ECCS pumps and then increases to the pressurizer safety valve setpoint. The heatup ends when the intact steam generators reach their main steam safety valve

(MSSV) setpoint and the combination of steam relief through the MSSV's and EFW injection match core decay heat plus RCP heat.

The minimum DNBR throughout the transient remains above the safety analysis limit value. Therefore, no fuel damage will occur.

5.2.8.3 Radiological Consequences

No fuel failures are predicted for this event. The radiological consequences resulting from this malfunction are considerably less than those calculated for a main steam line rupture. The analyses performed assuming a rupture of a main steam line are given in Subsection 5.1.5.

5.2.8.4 Conclusions

Results of the analyses show that for the postulated feedwater line break, the Emergency Feedwater System capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. The minimum DNBR remains above the safety analysis limit. Therefore, no fuel damage will occur. The radiological consequences from the postulated feedwater line rupture are less than those presented for the postulated steam line break. All applicable acceptance criteria are met.

TABLE 5.2-1
(Sheet 1 of 5)

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT CAUSE A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
a. Turbine Trip		
1. With pressure control (most positive MTC)	Turbine trip, loss of main feed flow	0.0
	Initiation of steam release from steam generator safety valves	8.1
	High pressurizer pressure reactor trip point reached	8.1
	Rods begin to drop	10.1
	Peak pressurizer pressure occurs	12.5
2. With pressure control (most negative MTC)	Turbine trip, loss of main feed flow	0.0
	Initiation of steam release from steam generator safety valves	8.1
	High pressurizer pressure reactor trip point reached	8.6
	Rods begin to drop	10.6
	Peak pressurizer pressure occurs	12.5

TABLE 5.2-1
(Sheet 2 of 5)

TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
3. Without pressure control (most positive MTC)	Turbine trip, loss of main feed flow	0.0
	High pressurizer pressure reactor trip point reached	6.6
	Initiation of steam release from steam generator safety valves	8.1
	Rods begin to drop	8.6
	Peak pressurizer pressure occurs	10.8
4. Without pressure control (most negative MTC)	Turbine trip, loss of main feed flow	0.0
	High pressurizer pressure reactor trip point reached	6.4
	Initiation of steam release from steam generator safety valves	8.1
	Rods begin to drop	8.4
	Peak pressurizer pressure occurs	10.3

TABLE 5.2-1
(Sheet 3 of 5)

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT CAUSE A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident		Event	Time (seconds)
b.	Loss of Nonemergency AC Power to the Station Auxiliaries	AC power is lost	0
		Main feedwater flow stops	0
		Low-low steam generator water level trip	36.3
		Rods begin to drop	38.3
		Reactor coolant pumps begin to coast down	38.3
		Peak water level in pressurizer occurs	43
		Four steam generators begin to receive emergency feed from one motor-driven emergency feedwater pump	120
		Minimum steam generator inventory	490
c.	Loss of Normal Feedwater Flow	Main feedwater flow stops	0
		Low-low steam generator water level trip	36.3
		Rods begin to drop	38.3
		Peak water level in pressurizer occurs	42

TABLE 5.2-1
(Sheet 4 of 5)

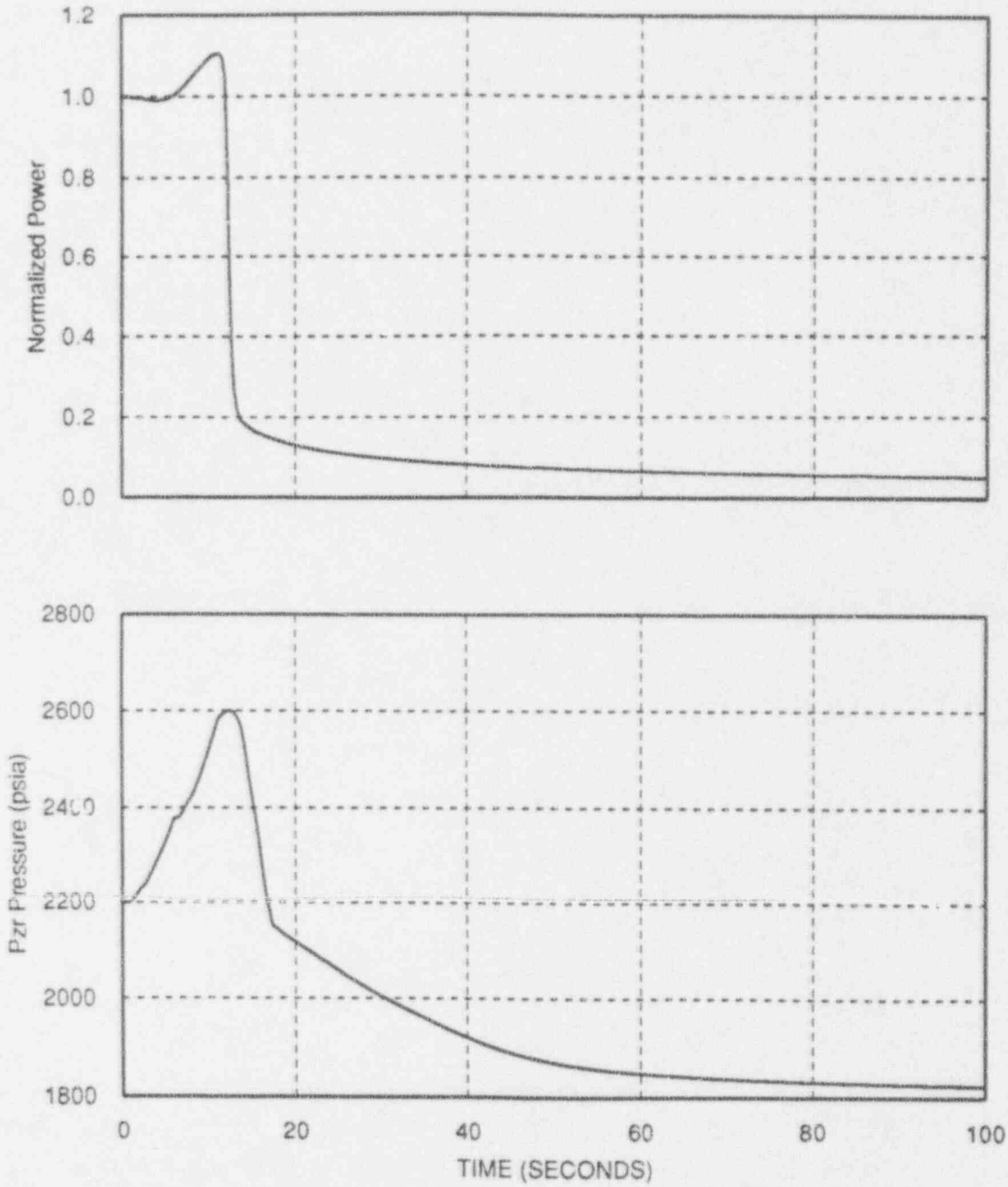
TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT CAUSE A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
	Four steam generators begin to receive emergency feed from motor-driven emergency feedwater pump	120
	Minimum steam generator inventory	≈675
d. Feedwater System Pipe Break		
	Main feedwater line rupture occurs	0.0
	Pressurizer safety valve setpoint reached prior to reactor trip	6.0
	MSSV setpoint reached Prior to reactor trip	8.0
	Low-low steam generator level reactor trip setpoint reached in ruptured steam generator	19.0
	Rods begin to drop	21.0
	Emergency feedwater is started	96.0
	Low steam line pressure setpoint reached in ruptured steam generator	228.3
	All main steam line isolation valves close	235.3
	Safety injection flow started	258.3

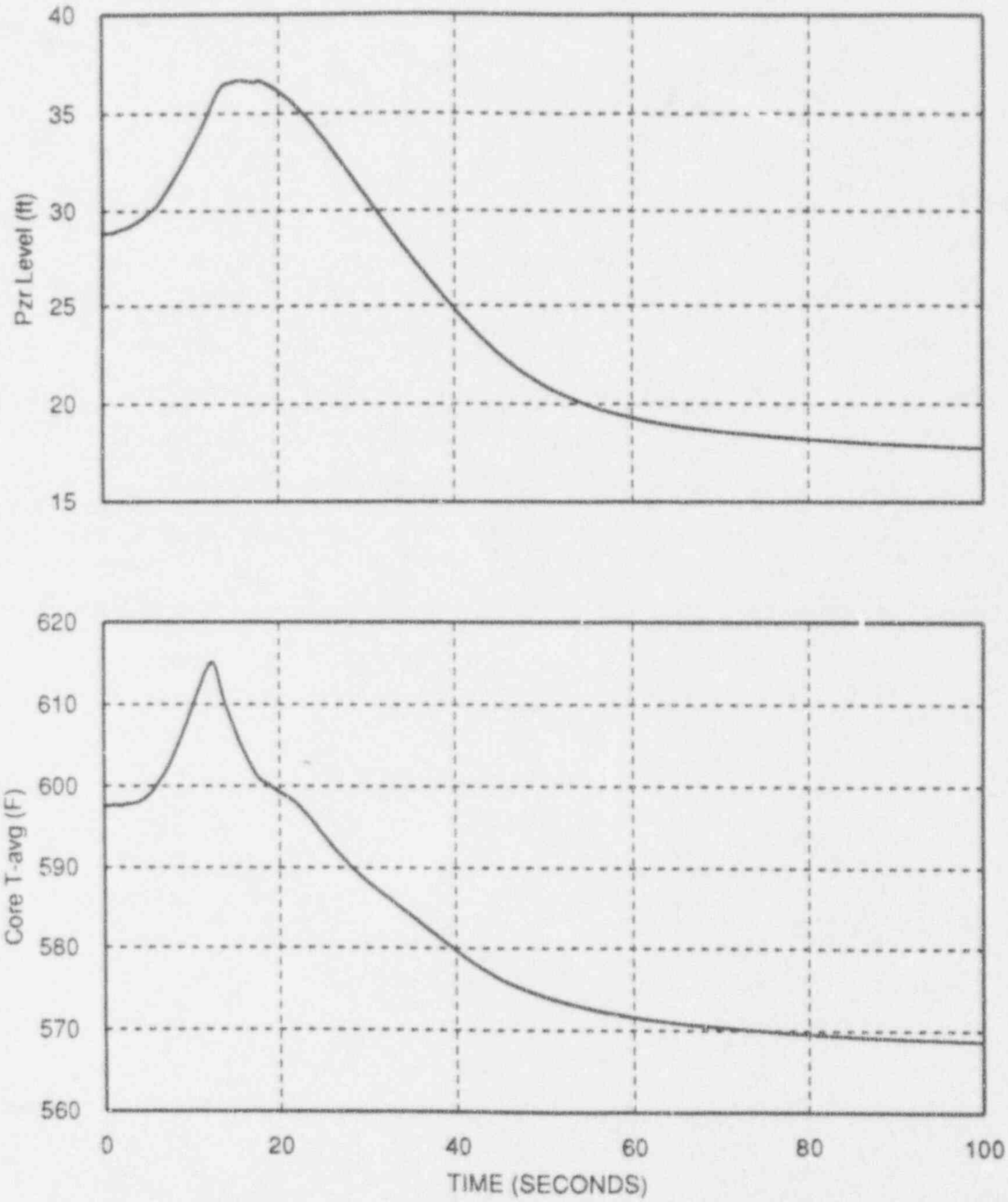
TABLE 5.2-1
(Sheet 5 of 5)

TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

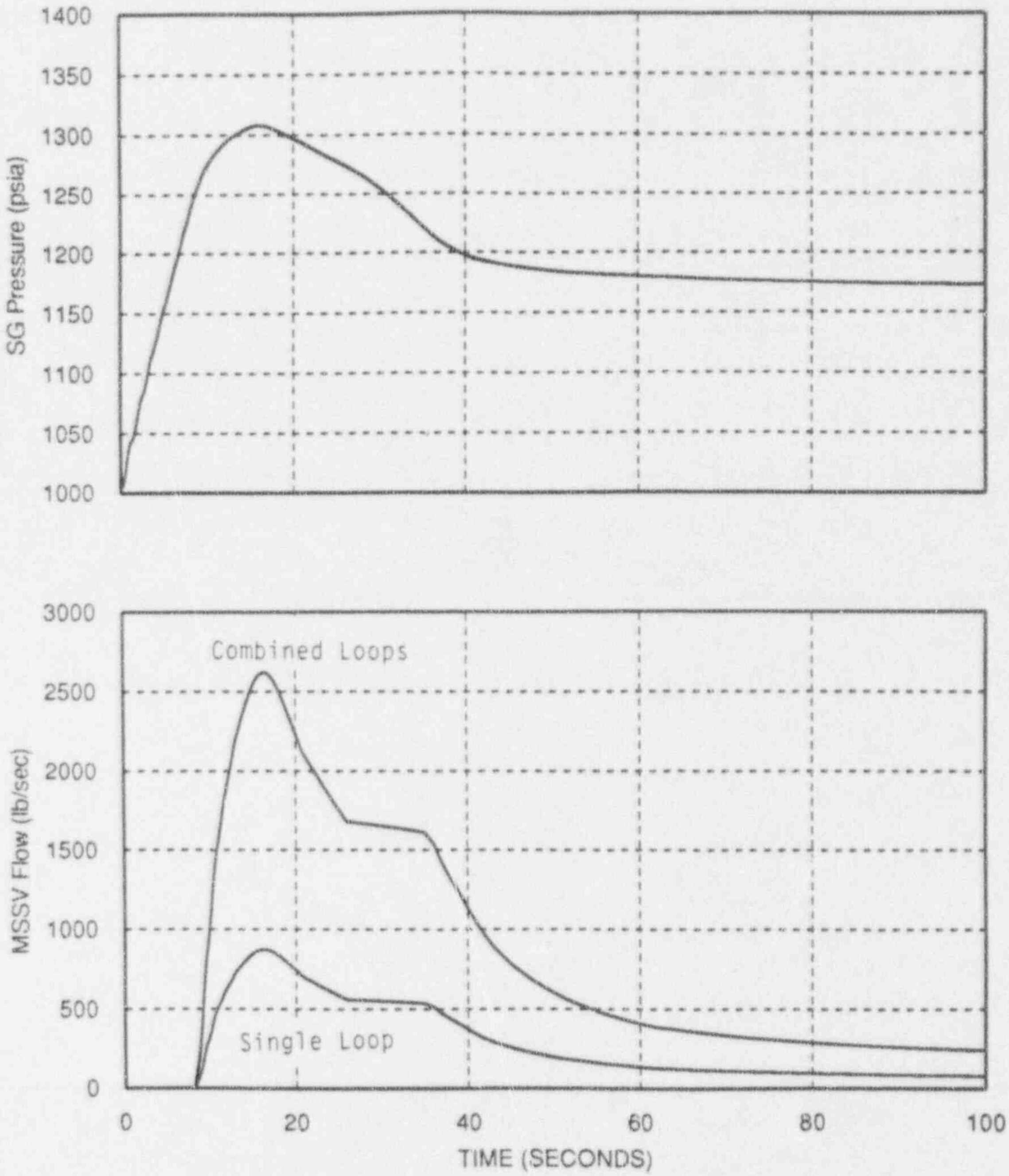
Accident	Event	Time (seconds)
Feedwater System Pipe Break (Continued)	Ruptured steam generator inventory completely discharged through break	324.0
	Feedwater lines are purged and emergency feedwater is delivered to intact steam generators	332.0
	Safety injection flow terminated	1148.0
	Pressurizer safety valve setpoint reached	1222.0
	Steam generator safety valve setpoint reached in intact steam generators	1842.0
	Core decay heat plus pump heat decrease to emergency feedwater heat removal capacity	4484.0



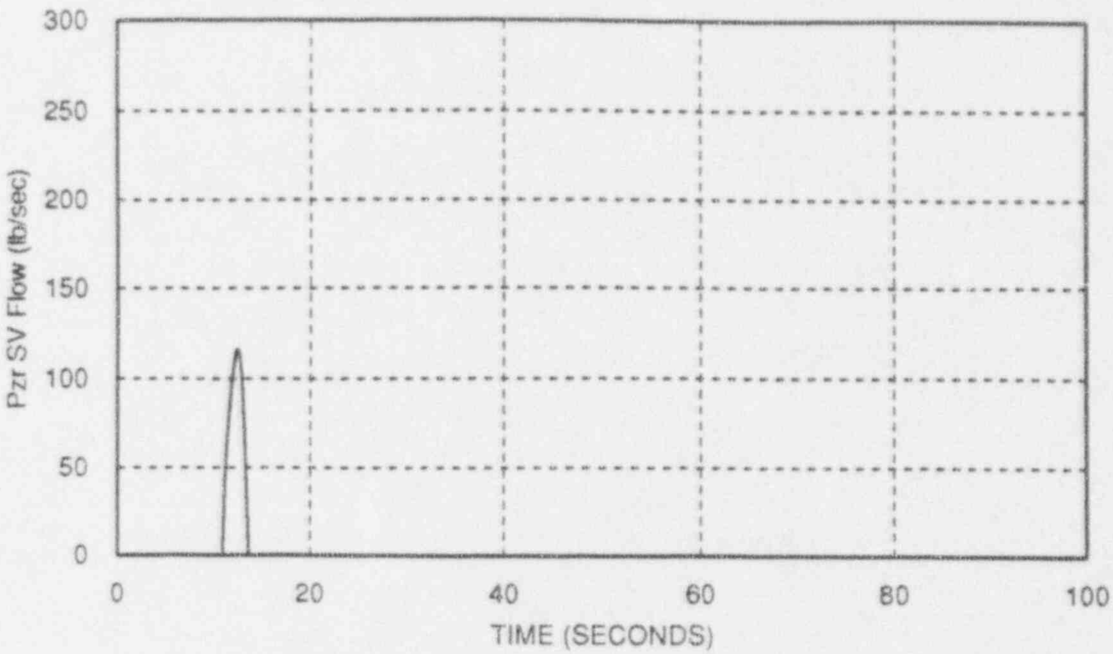
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Positive MTC FIGURE 5.2-1 , Sh. 1



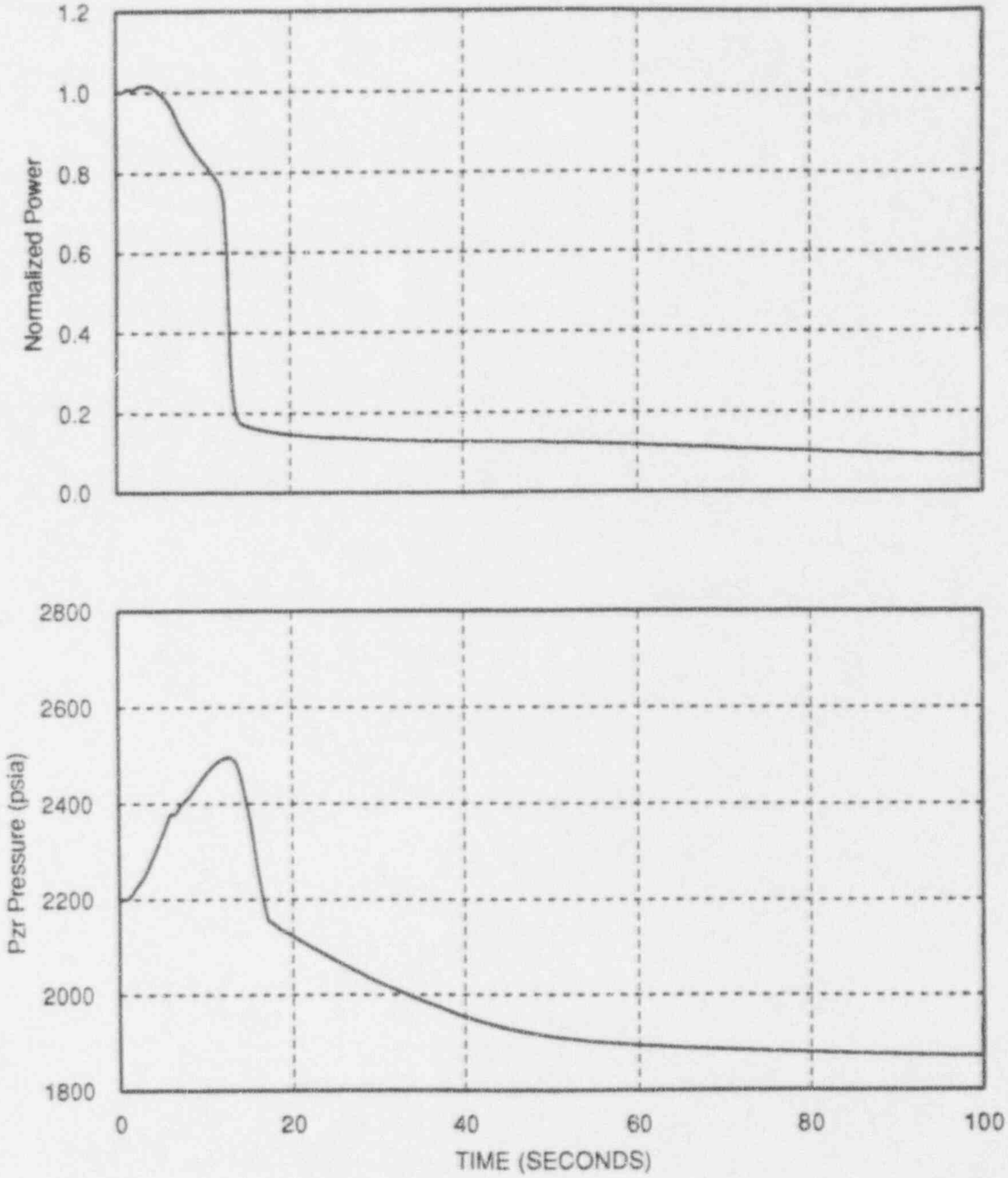
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Positive MTC FIGURE 5.2-1 , Sh. 2



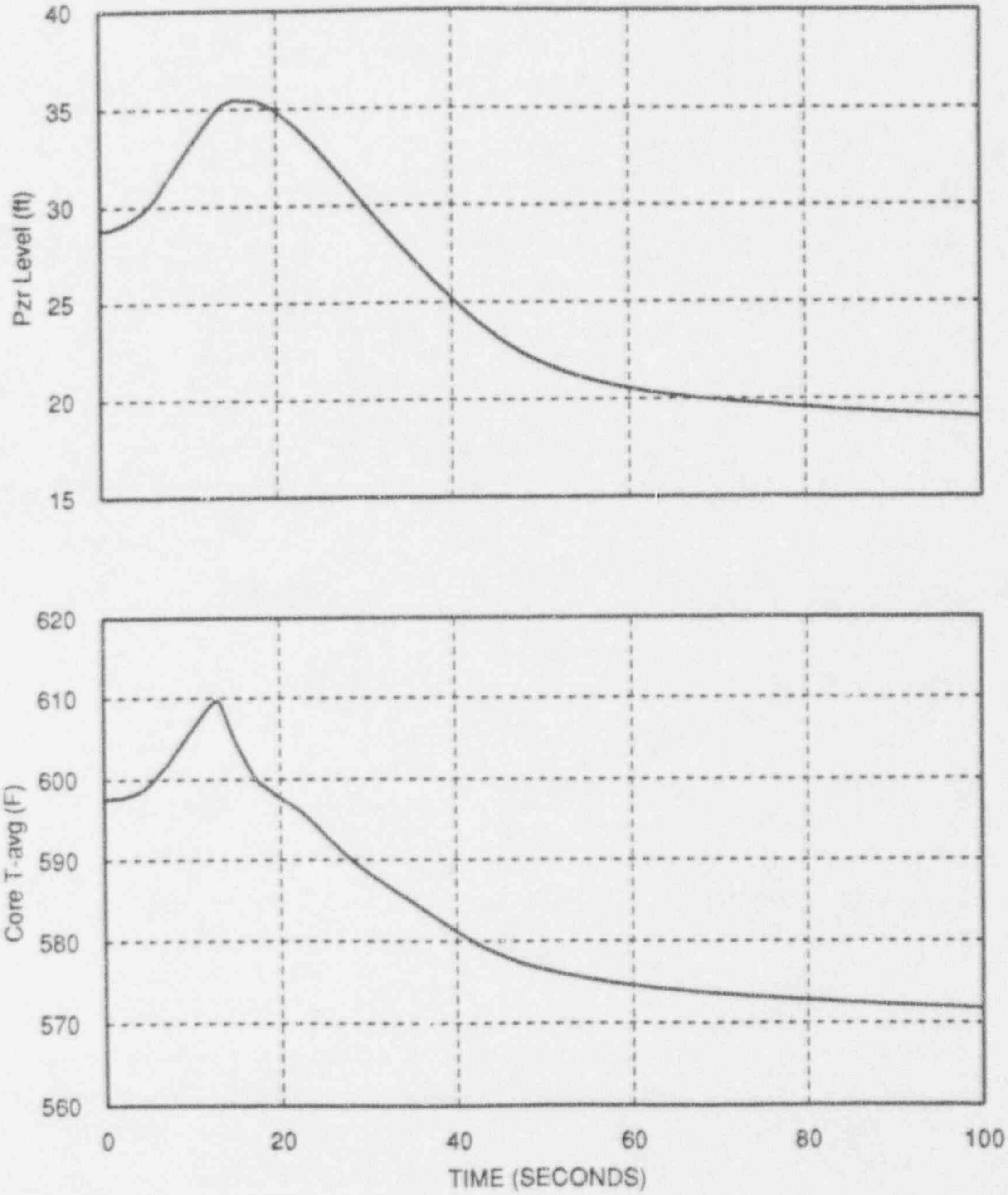
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Positive MTC FIGURE 5.2-1 , Sh. 3



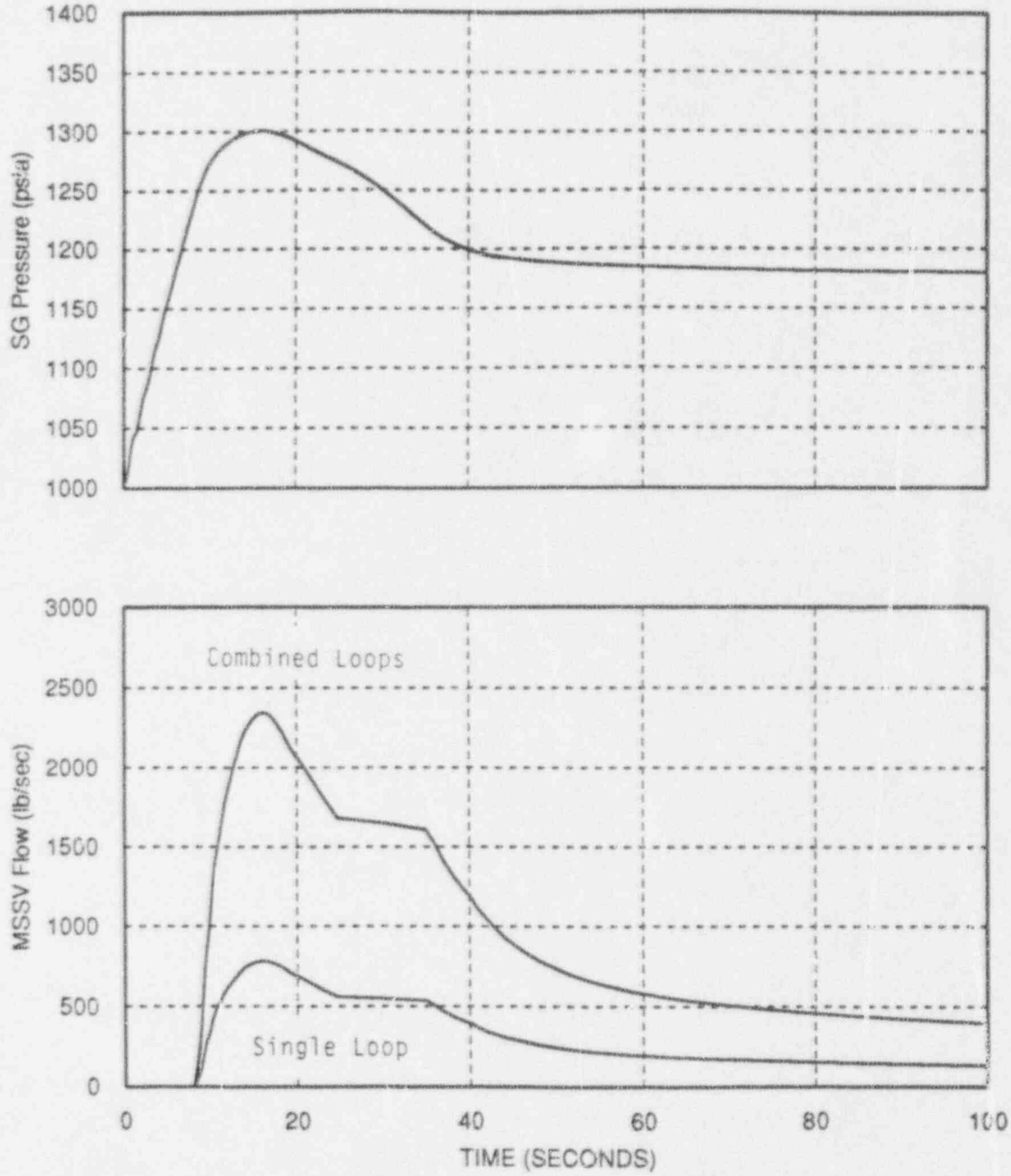
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Positive MTC FIGURE 5.2-1 , Sh. 4



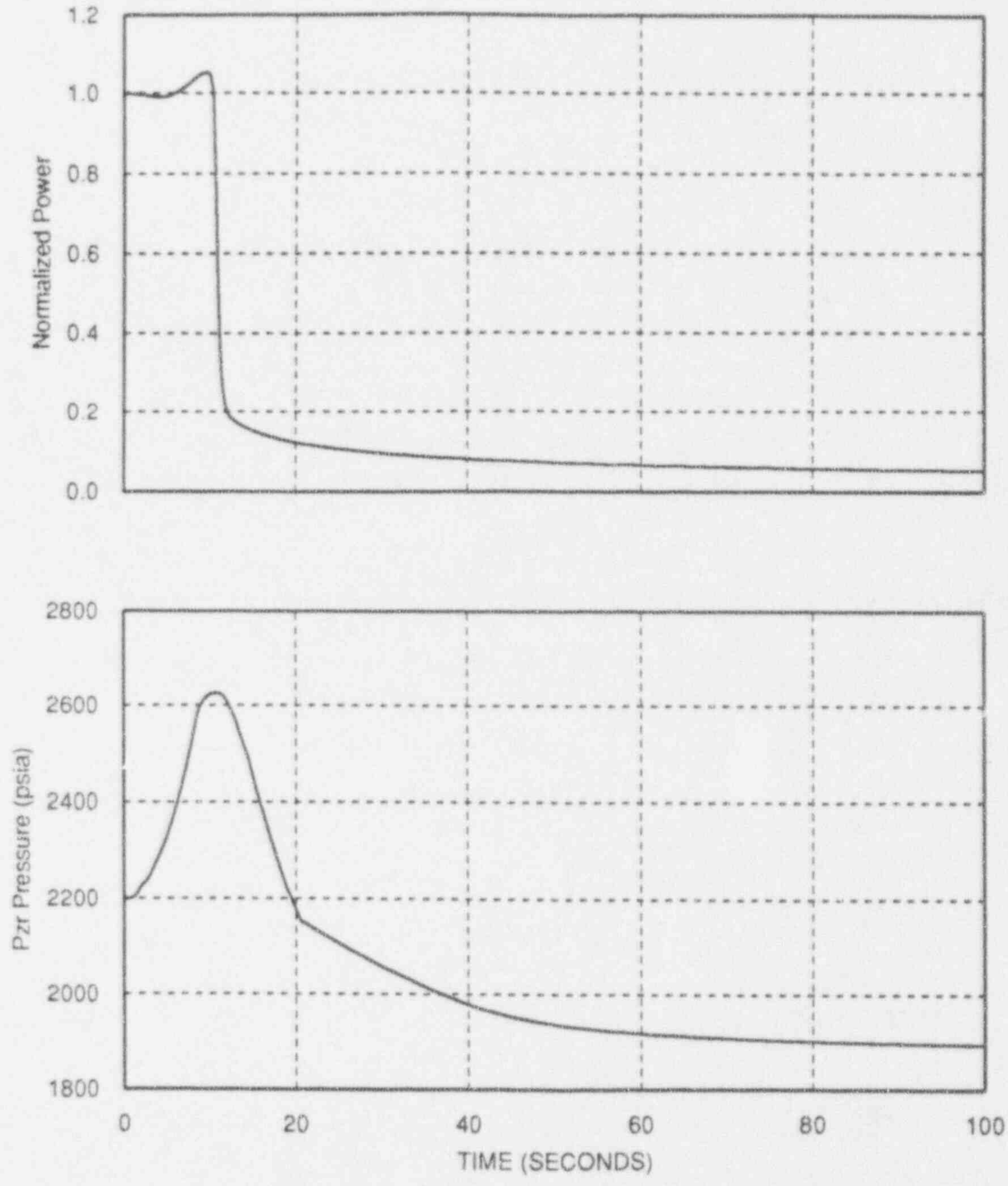
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Negative MTC FIGURE 5.2-2 , Sh. 1



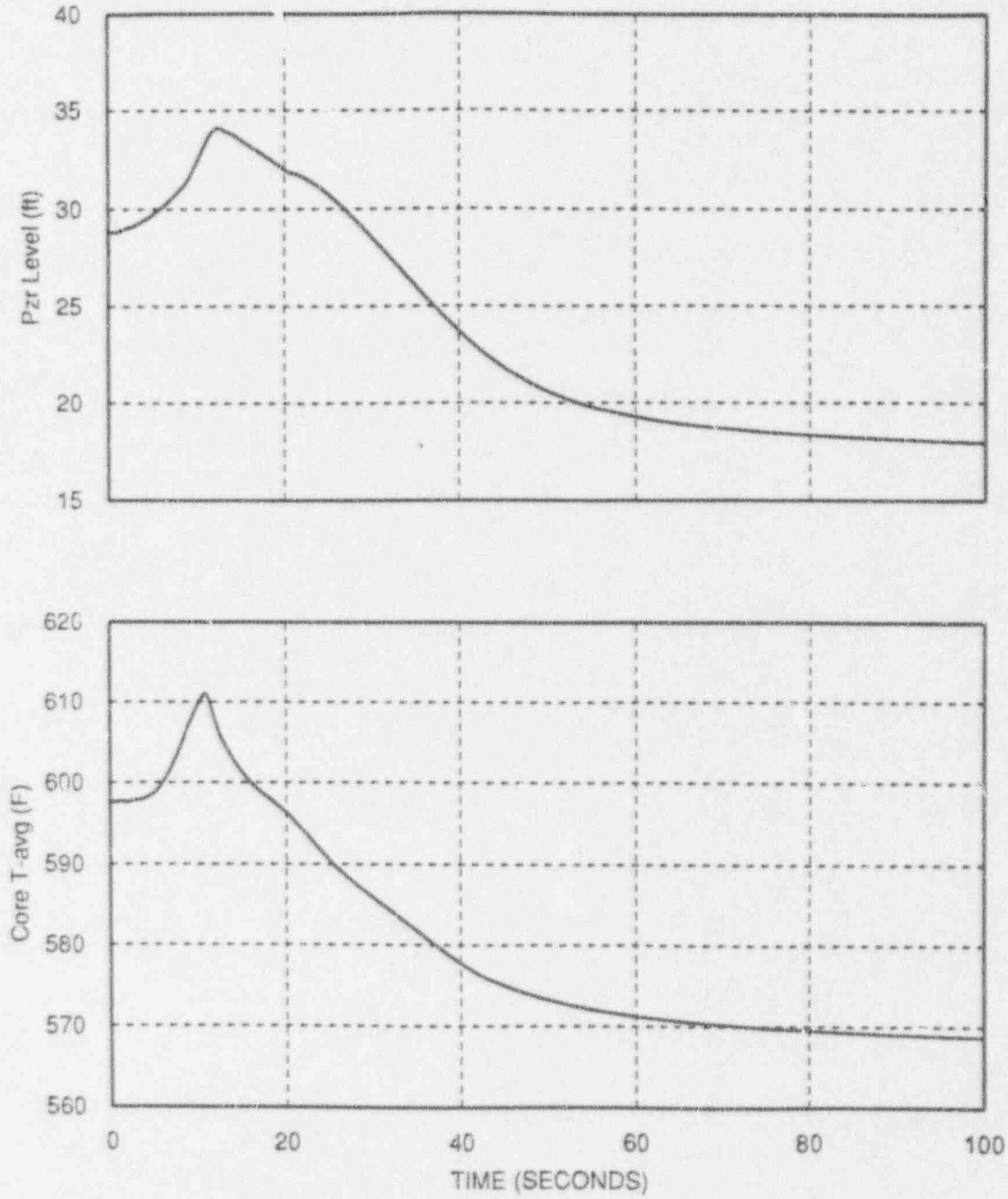
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Negative MTC FIGURE 5.2-2 , Sh. 2



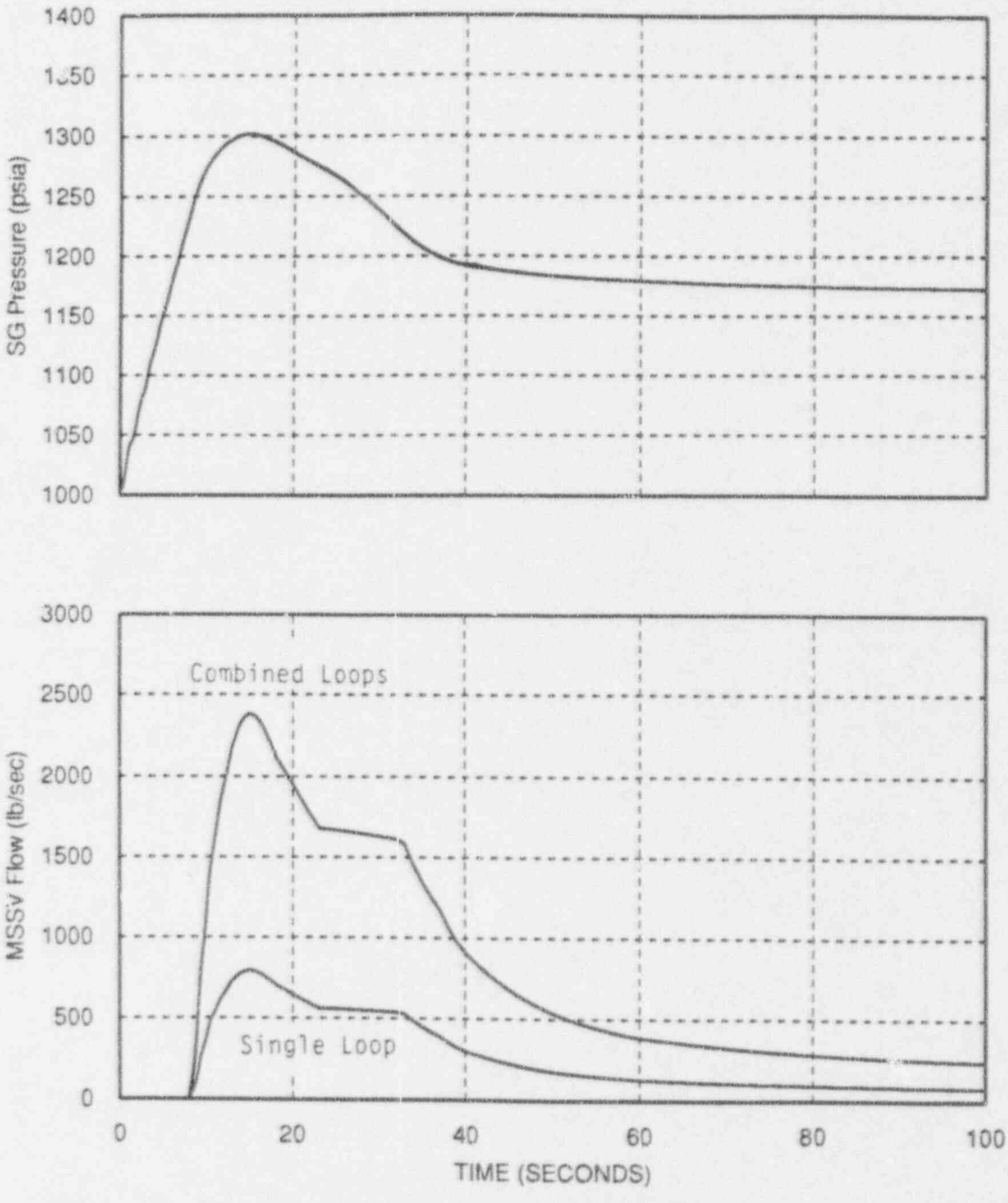
SEABROOK STATION	Turbine Trip Event With Pressure Control Most Negative MTC FIGURE 5.2-2 , Sh. 3



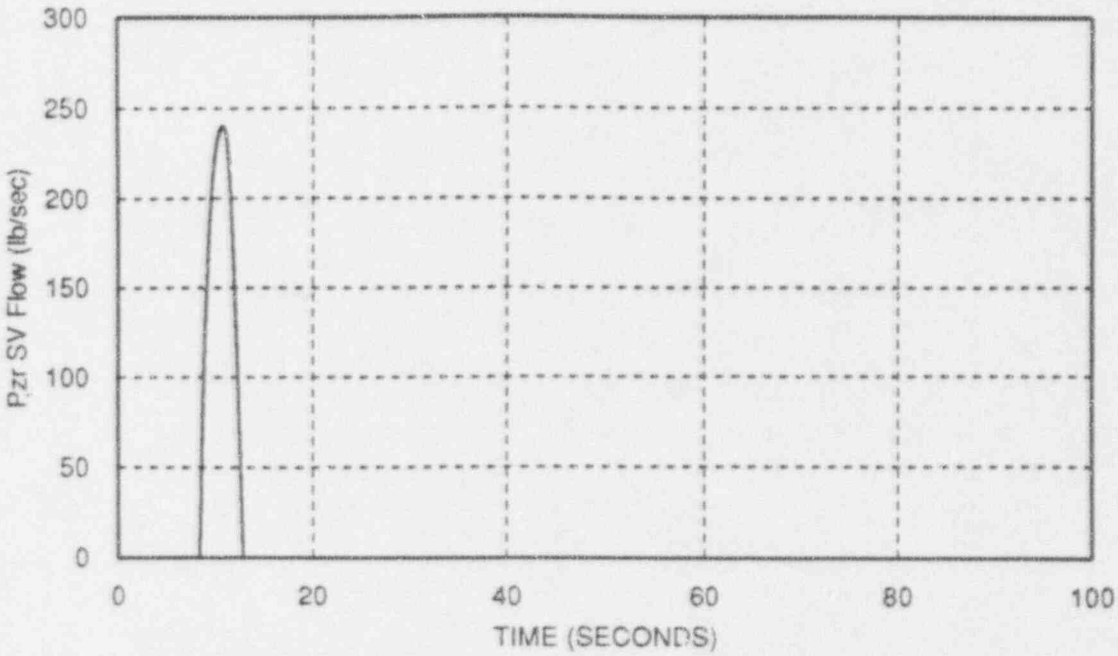
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Positive MTC FIGURE 5.2-3 , Sh. 1



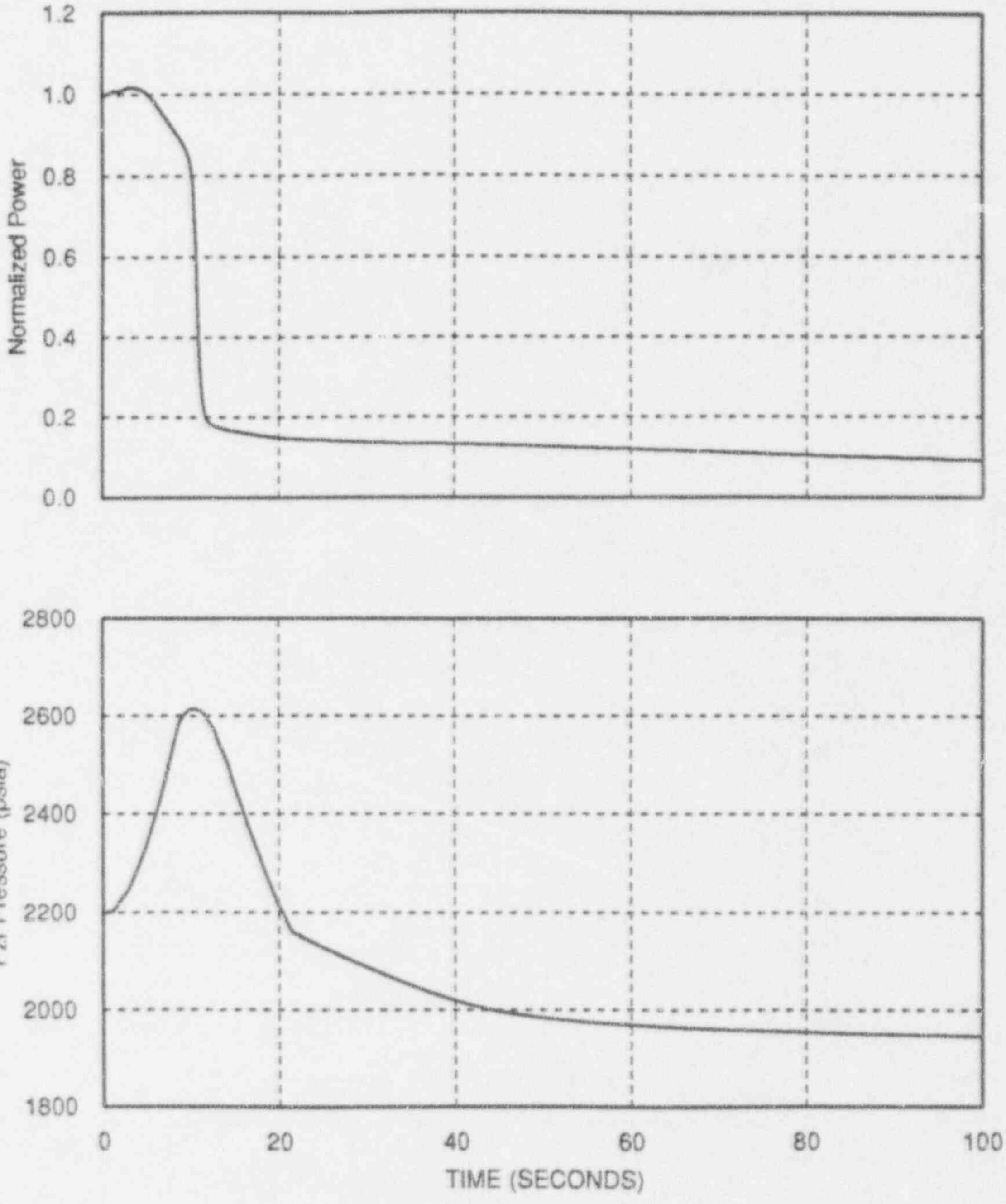
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Positive MTC FIGURE 5.2-3 , Sh. 2



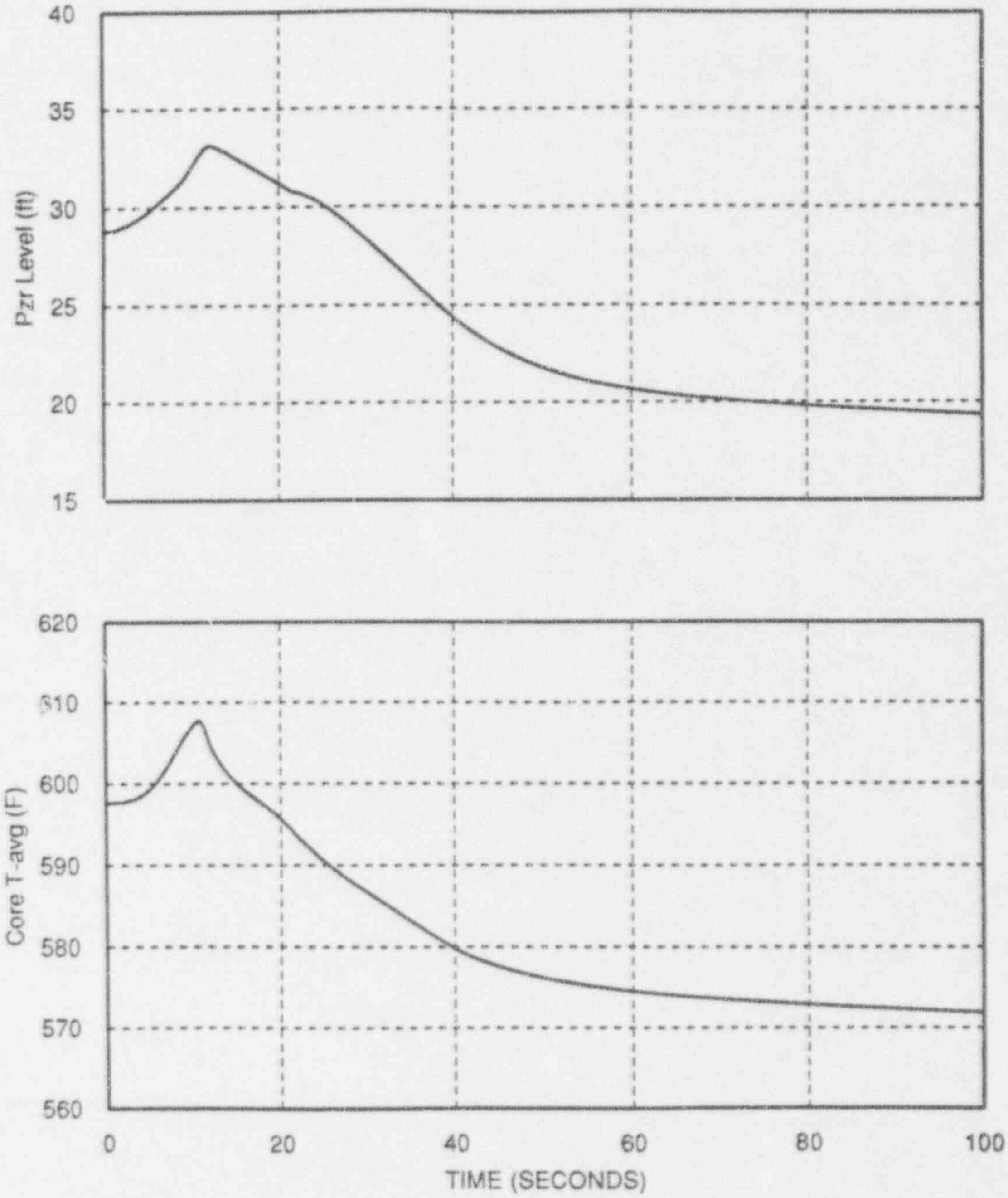
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Positive MTC FIGURE 5.2-3 , Sh. 3



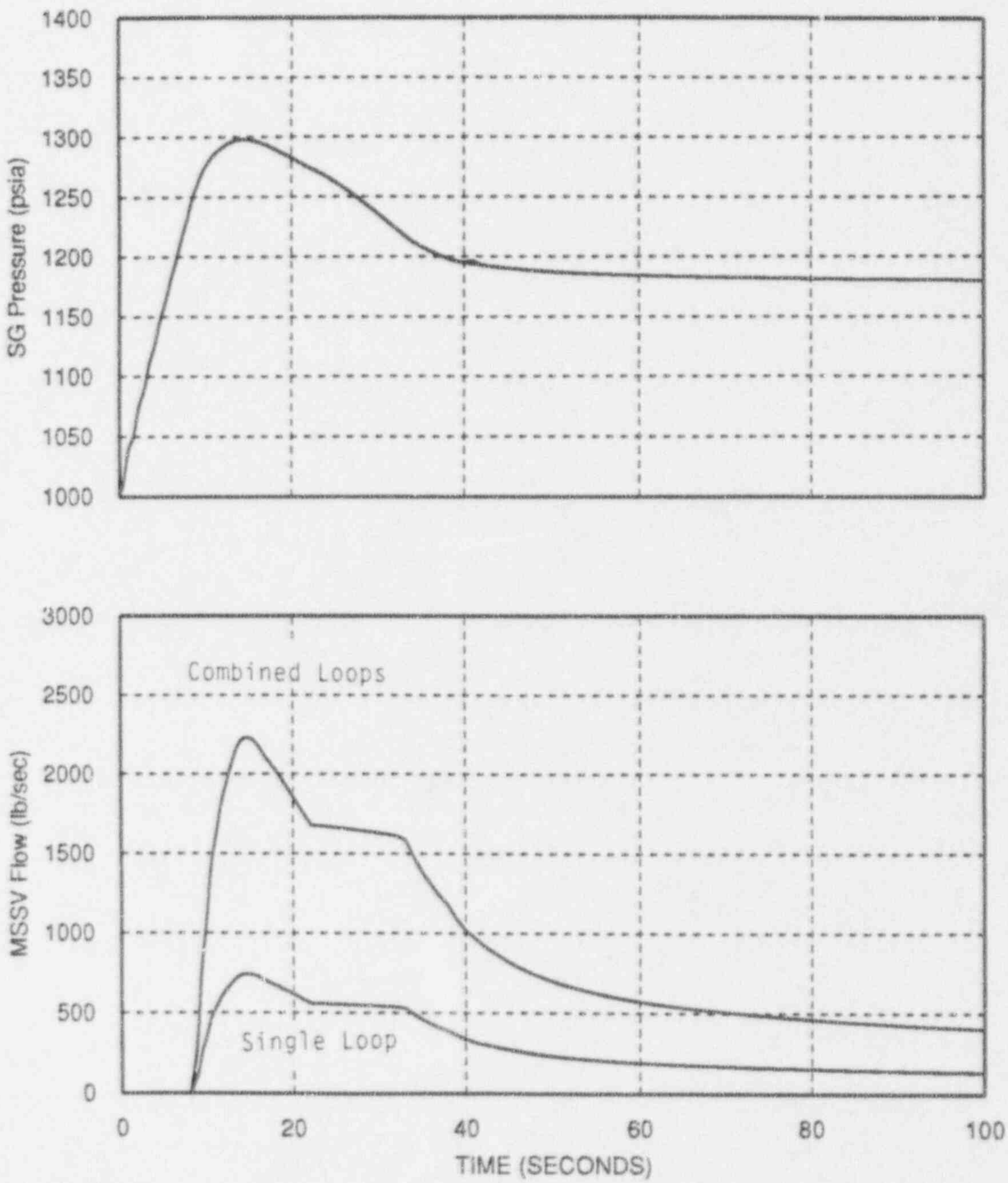
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Positive MTC FIGURE 5.2-3 , Sh. 4



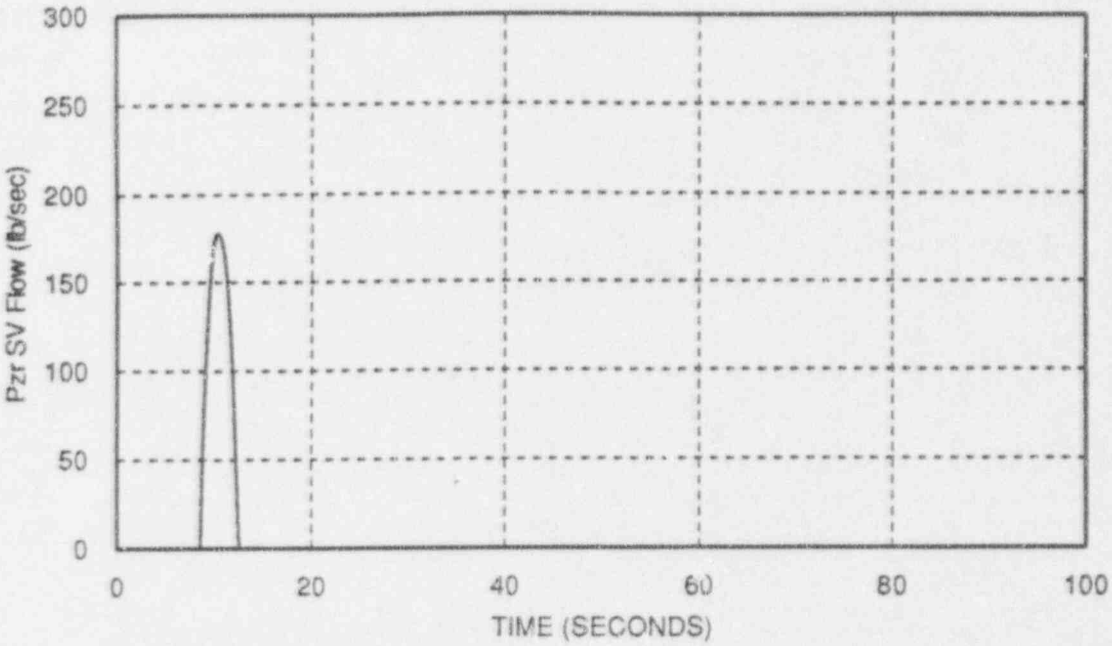
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Negative MTC FIGURE 5.2-4 , Sh. i



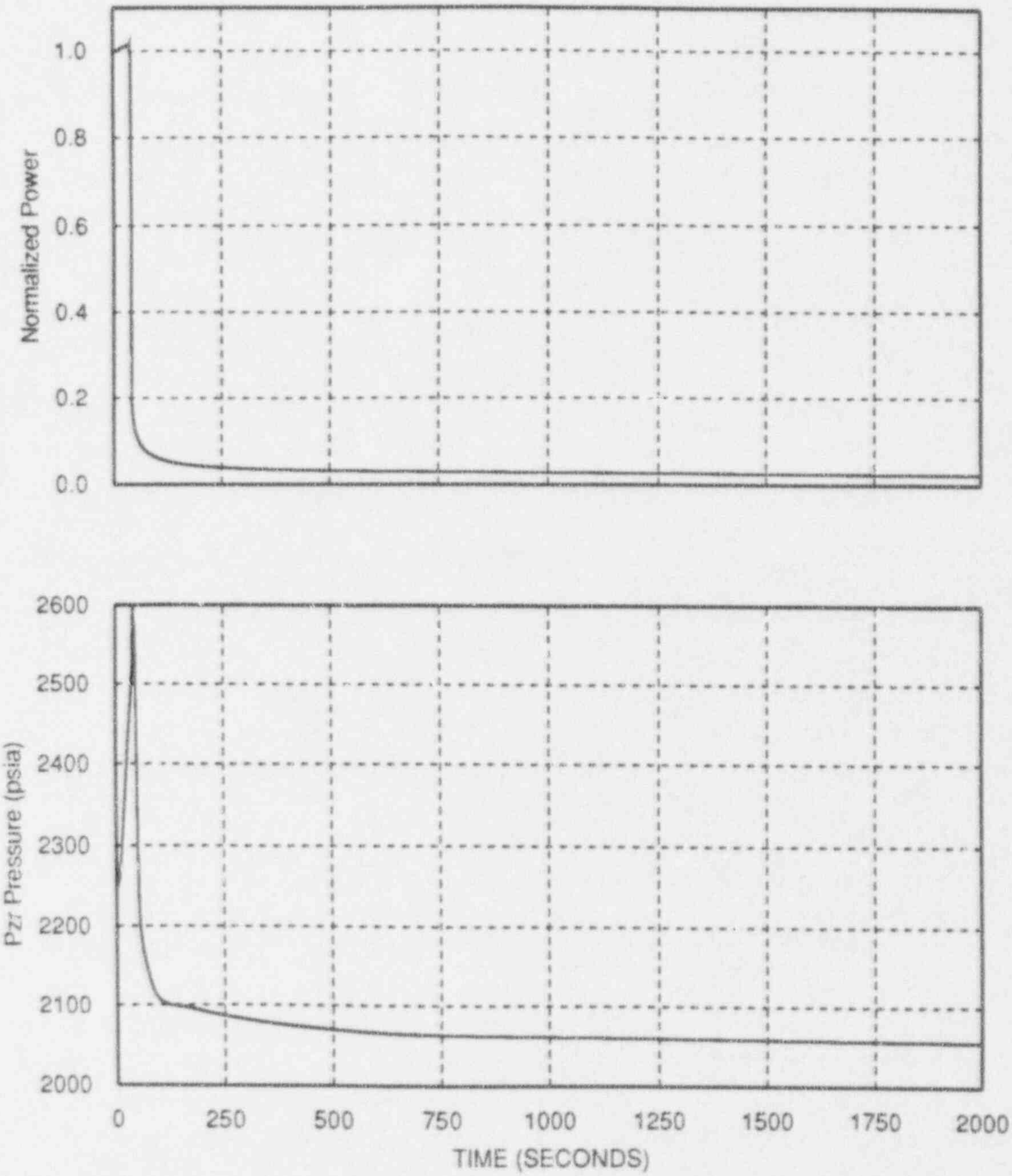
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Negative MTC FIGURE 5.2-4 , Sh. 2



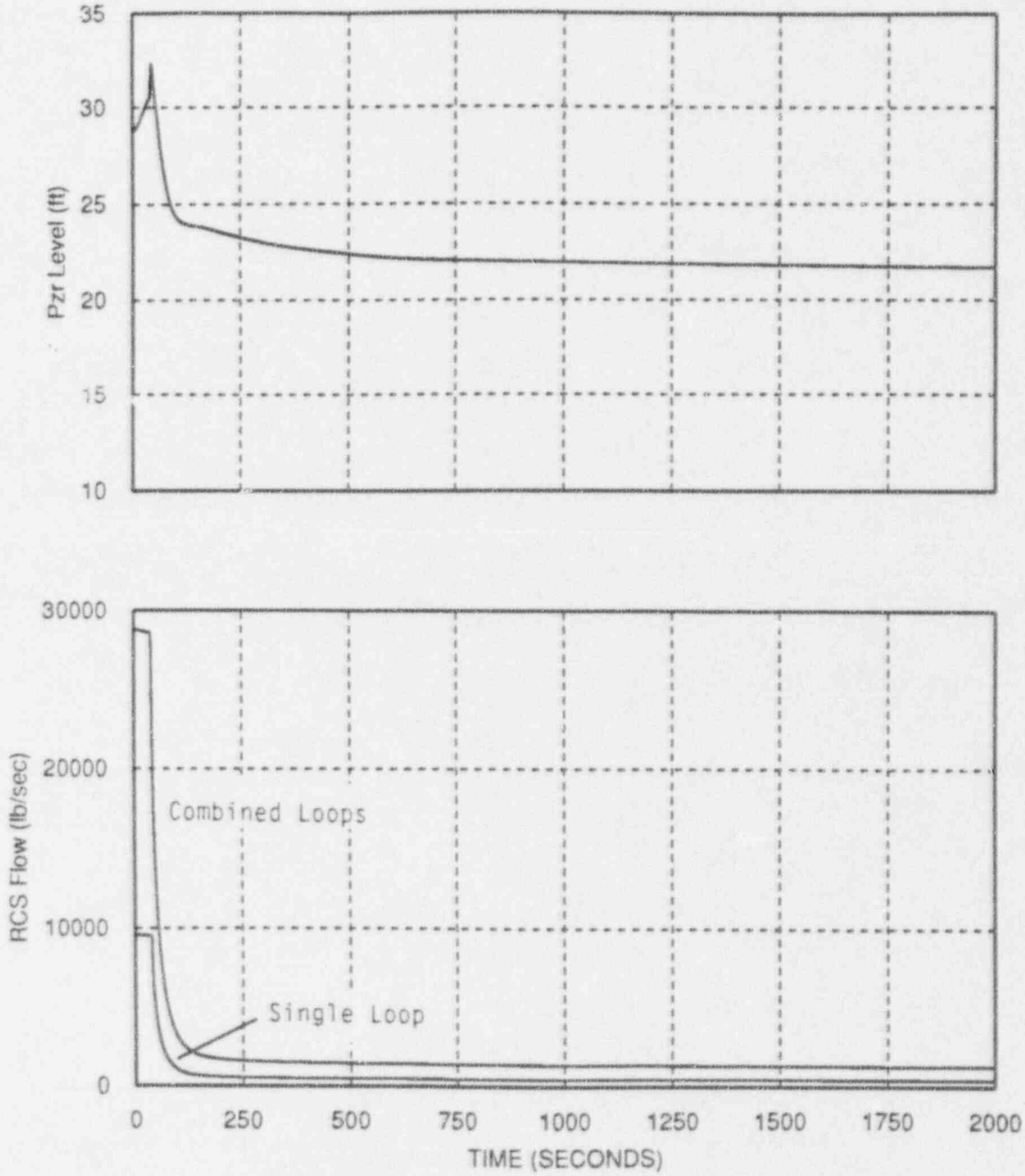
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Negative MTC FIGURE 5.2-4 , Sh. 3



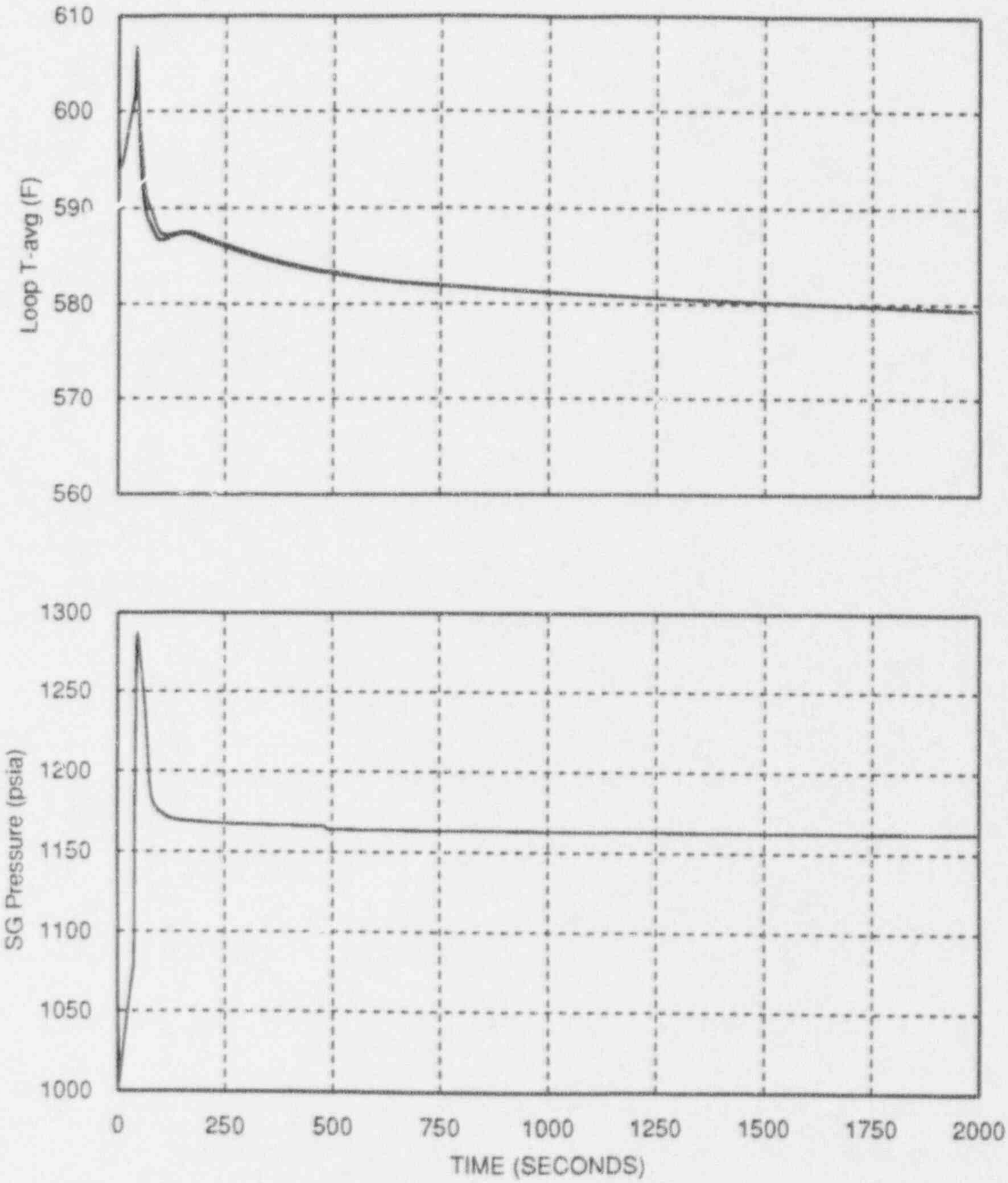
SEABROOK STATION	Turbine Trip Event Without Pressure Control Most Negative MTC FIGURE 5.2-4 , Sh. 4



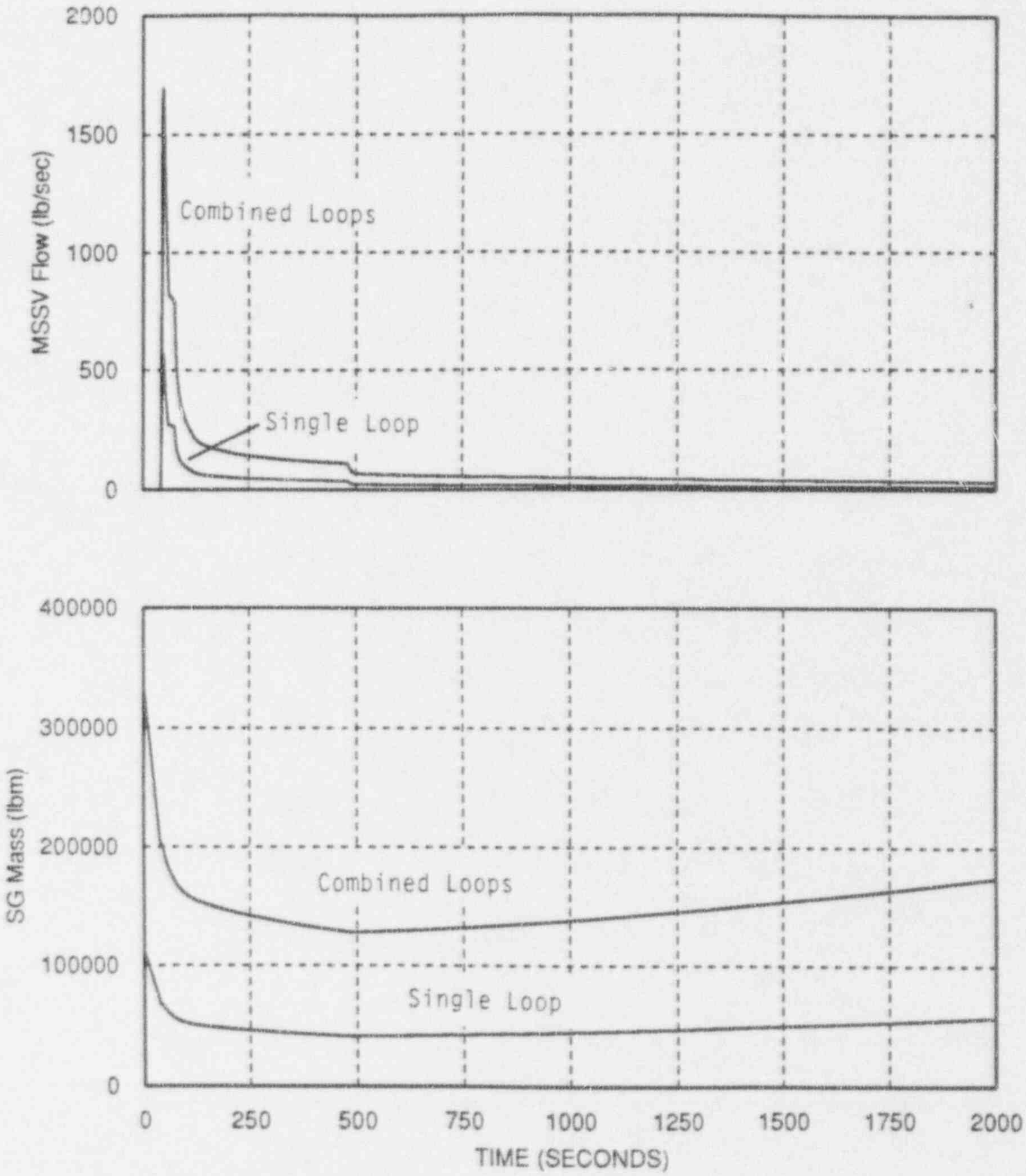
SEABROOK STATION	Loss of Non-Emergency AC Power FIGURE 5.2-5 , Sh. 1



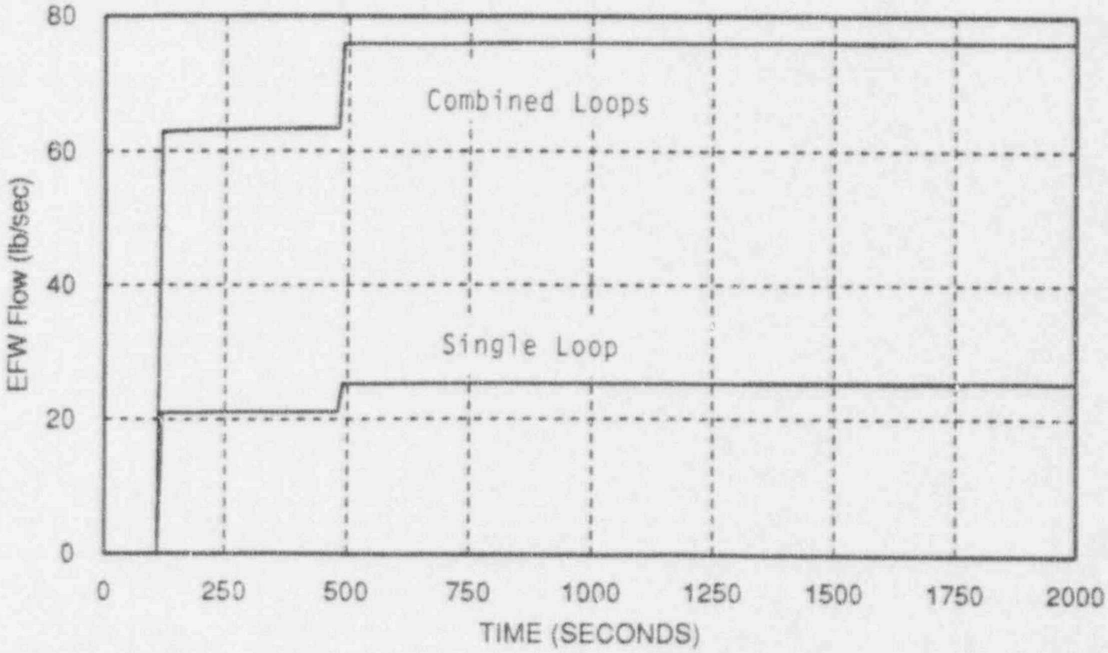
SEABROOK STATION	Loss of Non-Emergency AC Power FIGURE 5.2-5 , Sh. 2



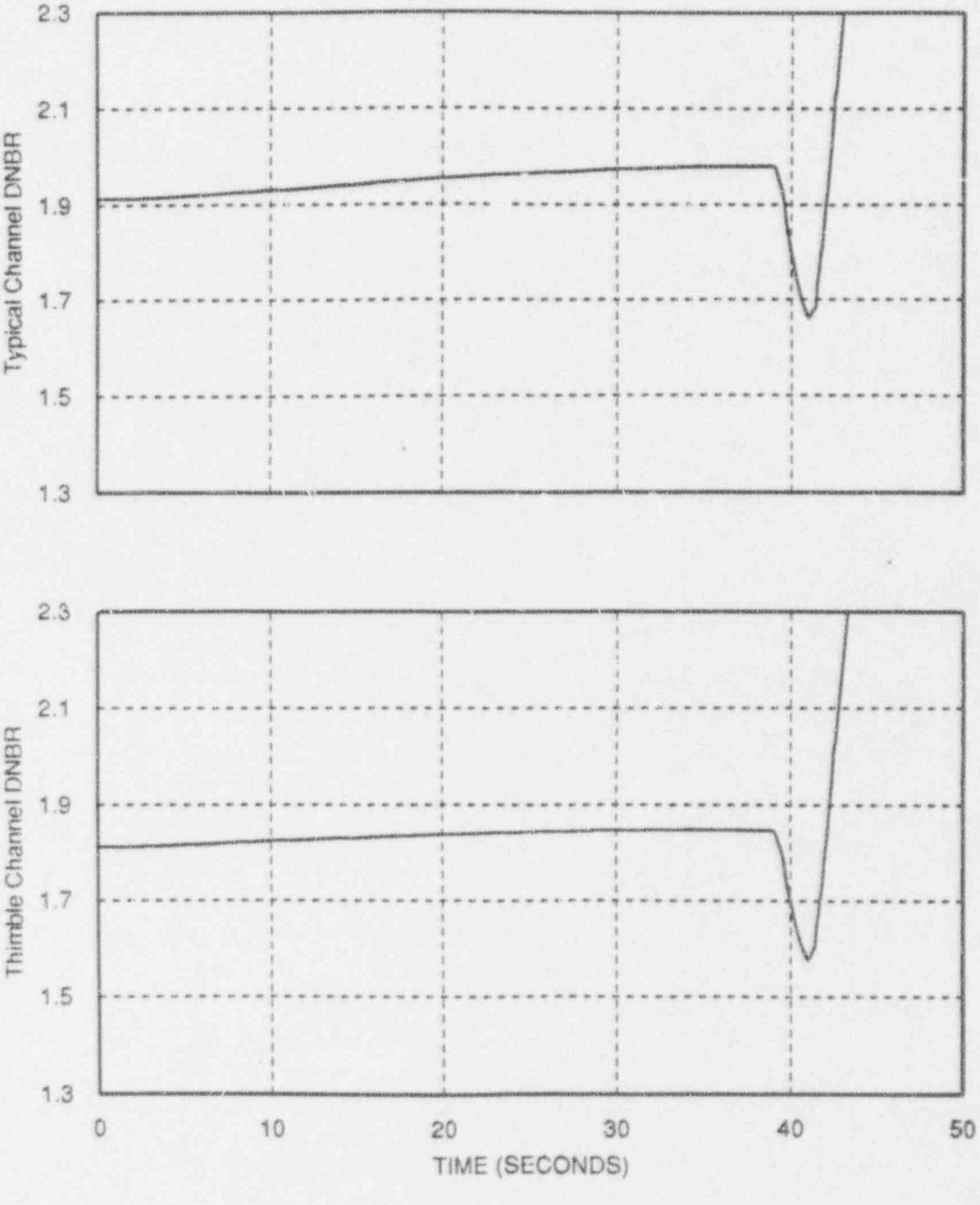
SEABROOK STATION	Loss of Non-Emergency AC Power FIGURE 5.2-5 , Sh. 3



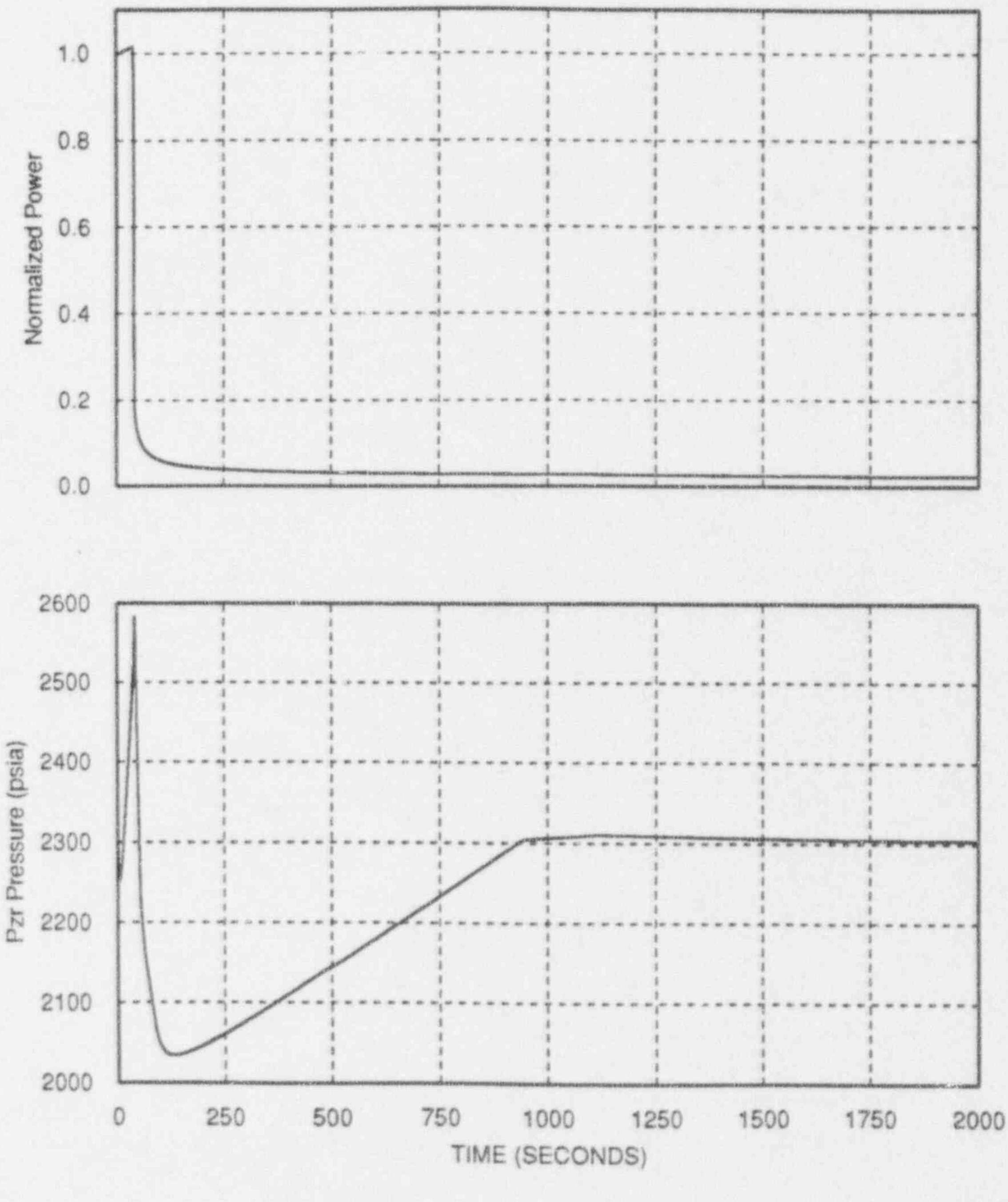
SEABROOK STATION	Loss of Non-Emergency AC Power FIGURE 5.2-5 , Sh. 4



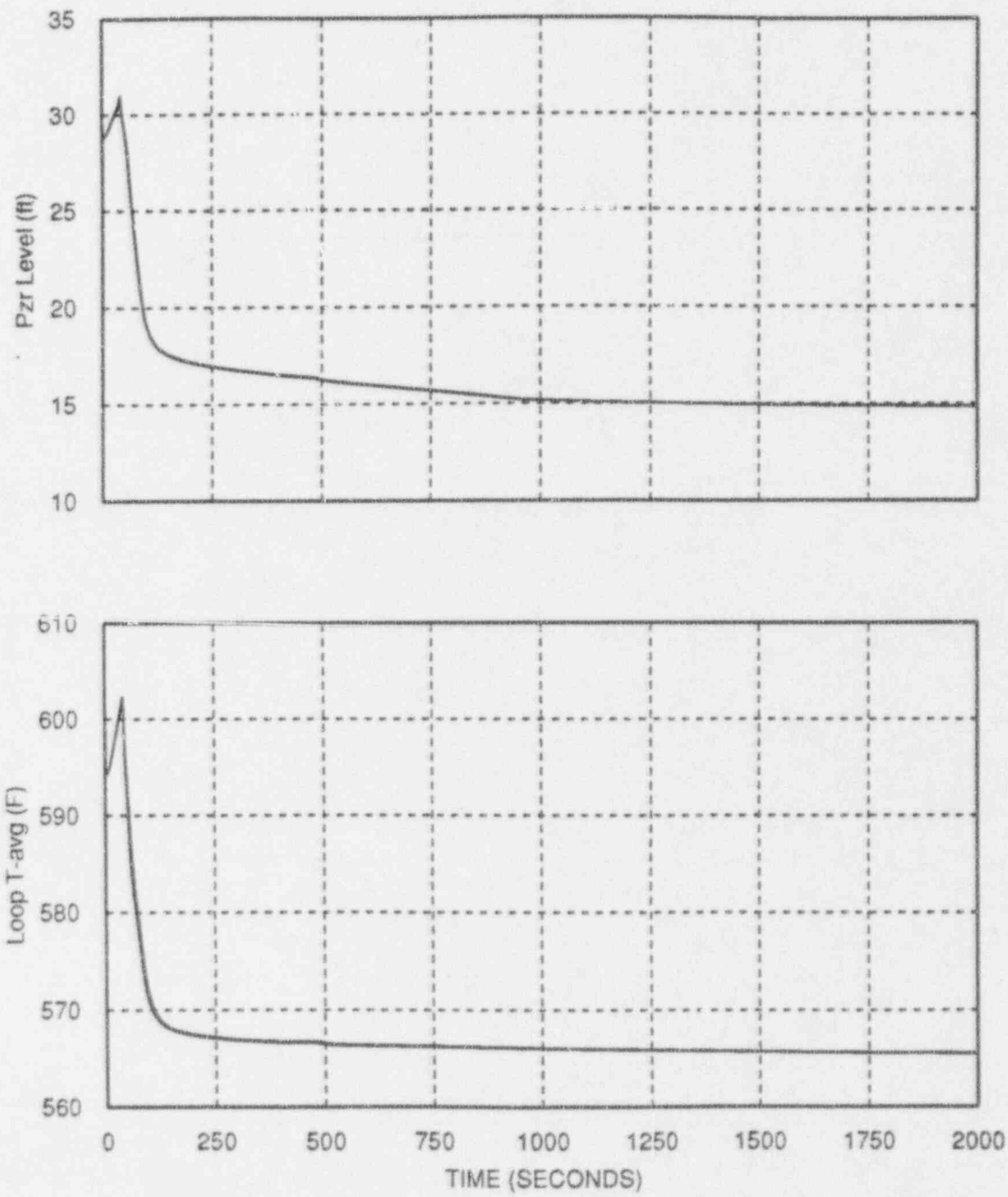
SEABROOK STATION	Loss of Non-Emergency AC Power FIGURE 5.2-5 , Sh. 5



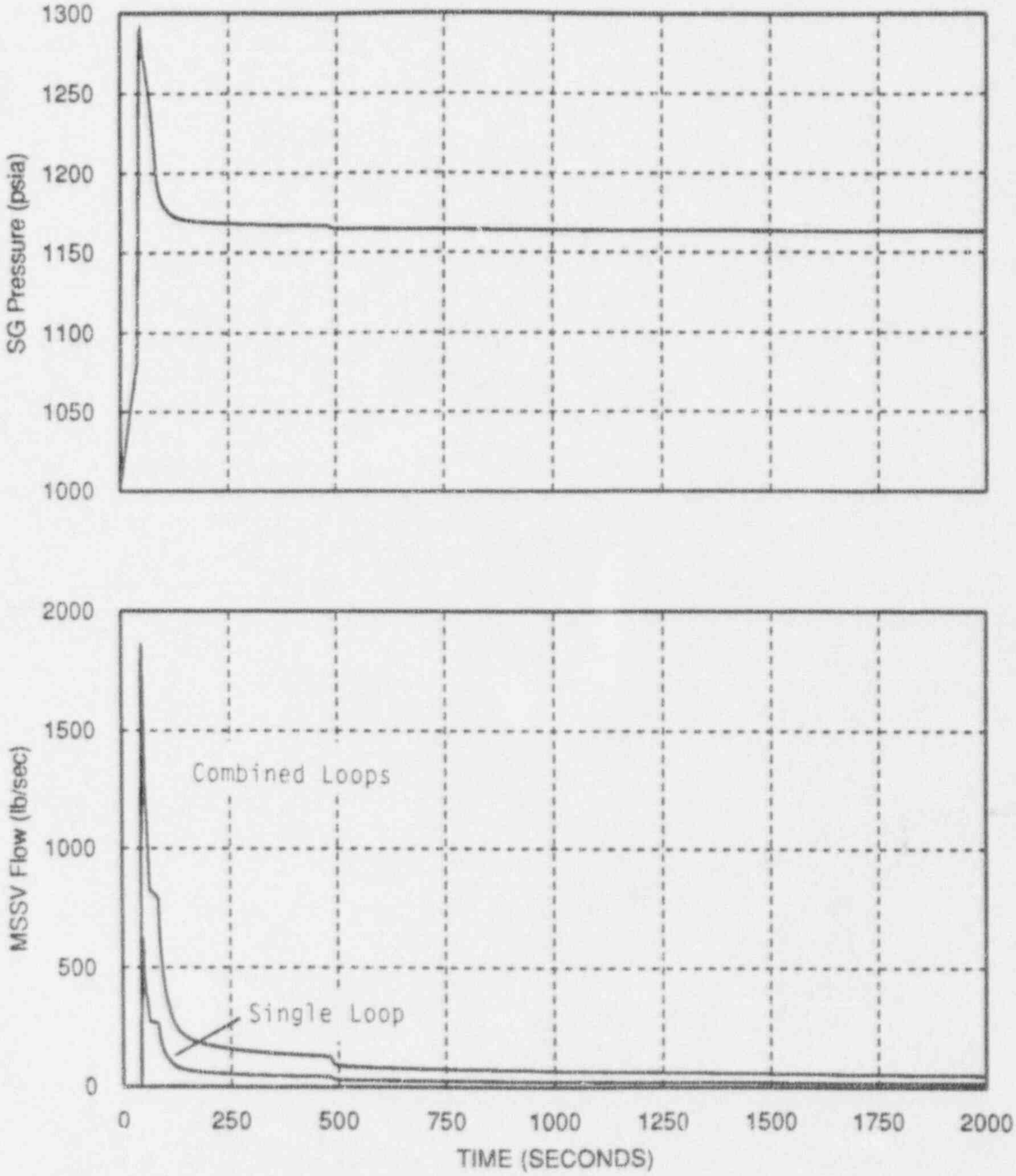
SEABROOK STATION	Loss of Non-Emergency AC Power FIGURE 5.2-5, Sh. 6



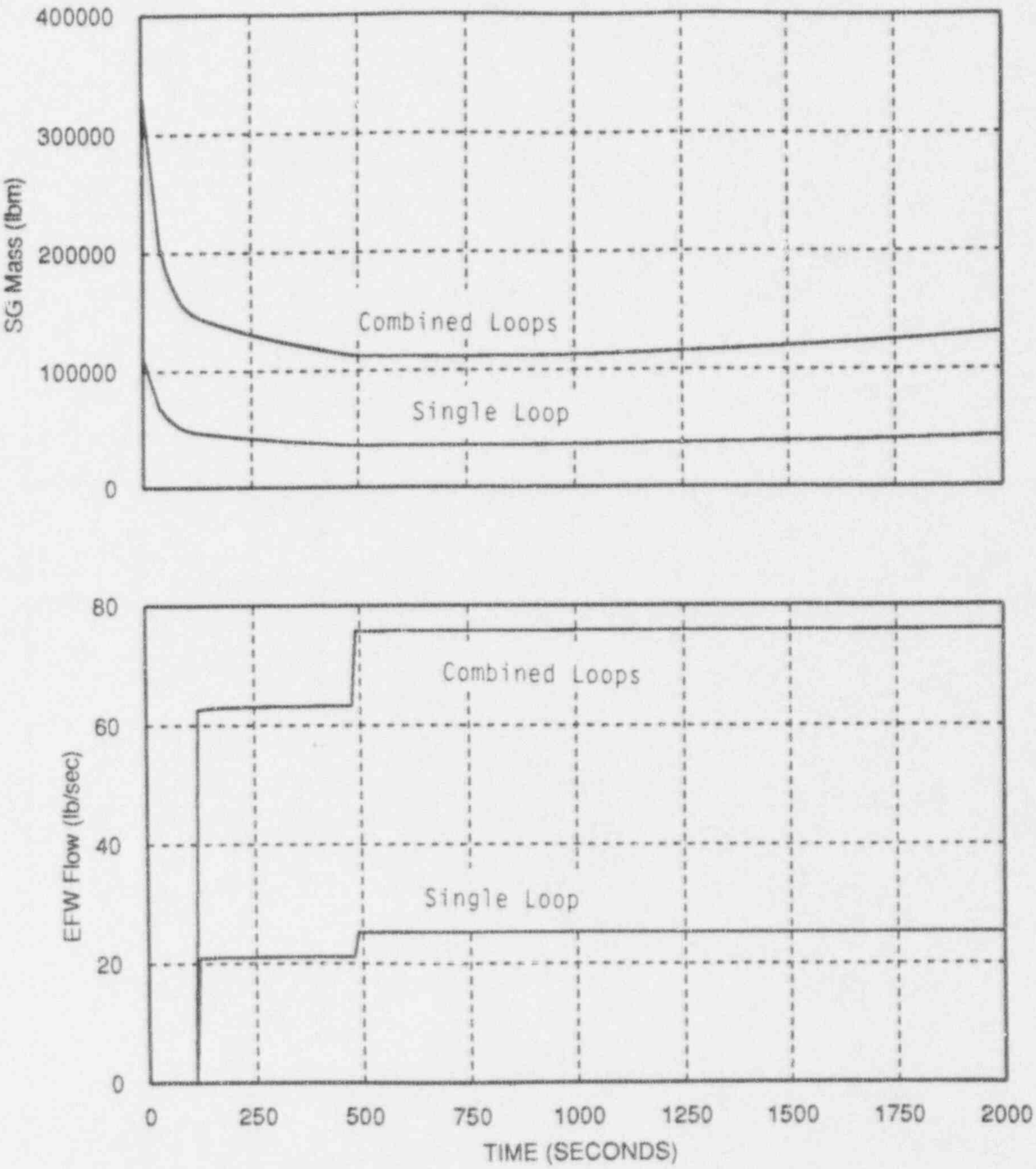
SEABROOK STATION	Loss of Normal Feedwater FIGURE 5.2-6 , Sh. 1



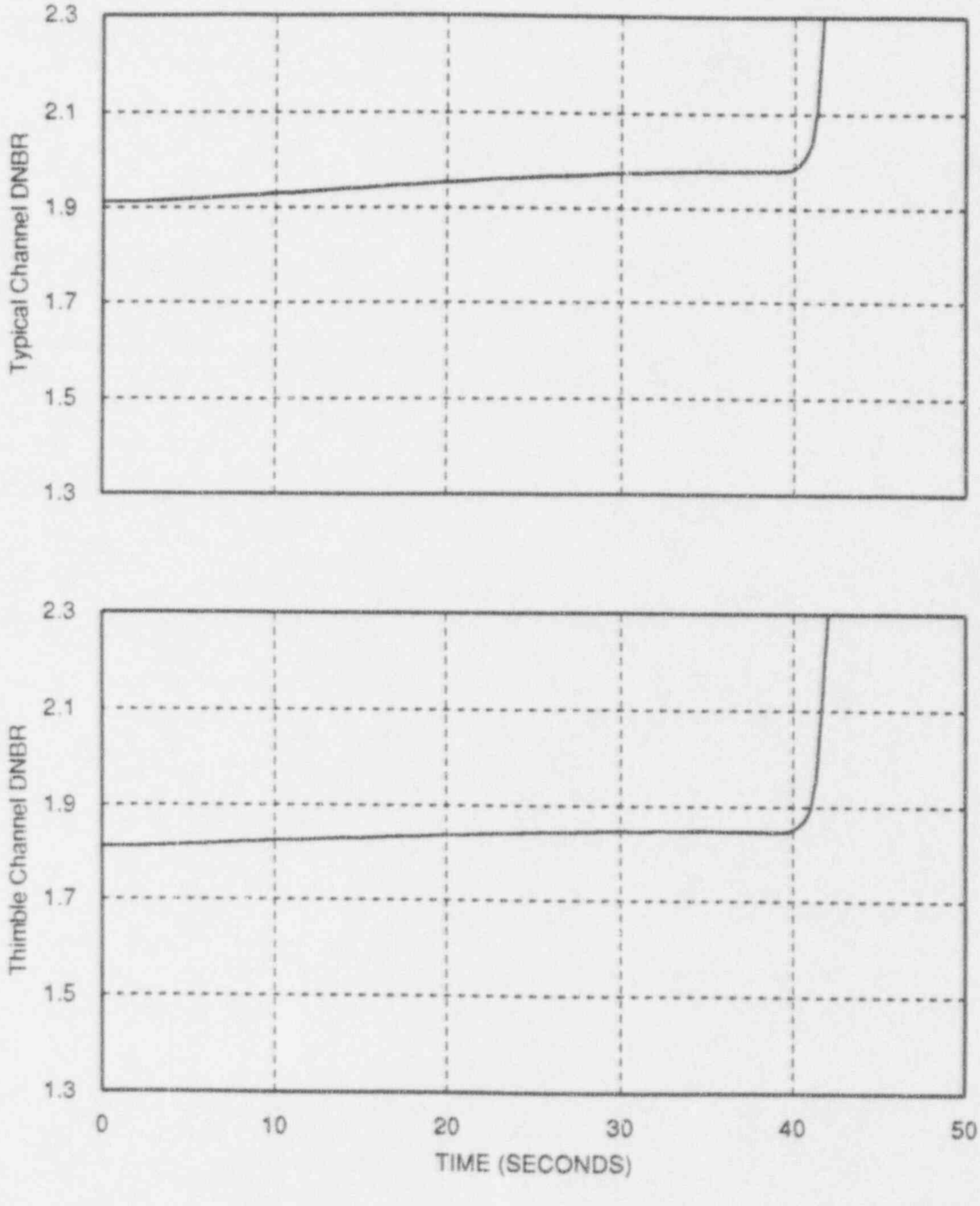
SEABROOK STATION	Loss of Normal Feedwater FIGURE 5.2-6 , Sh. 2



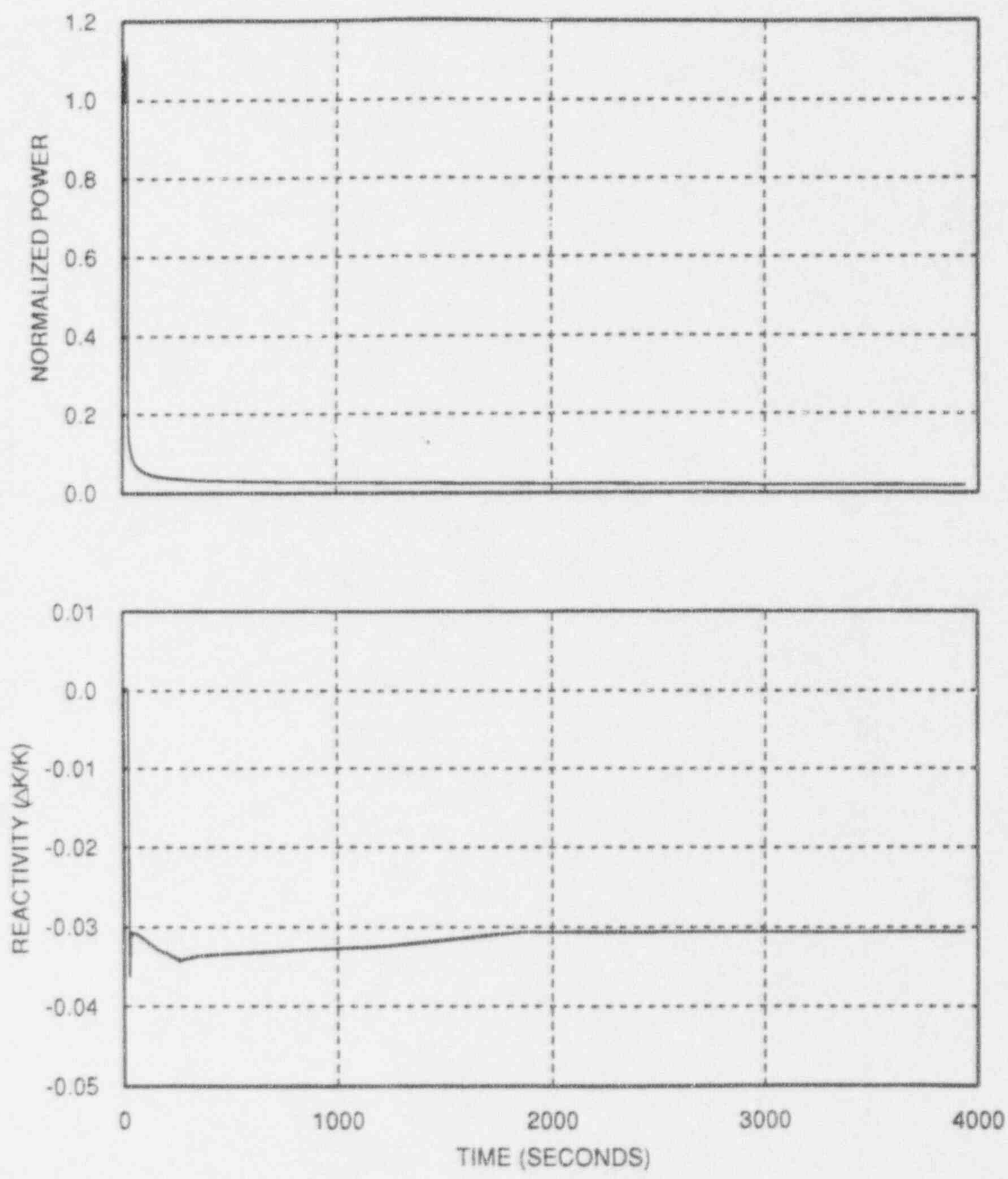
SEABROOK STATION	Loss of Normal Feedwater FIGURE 5.2-6 , Sh. 3



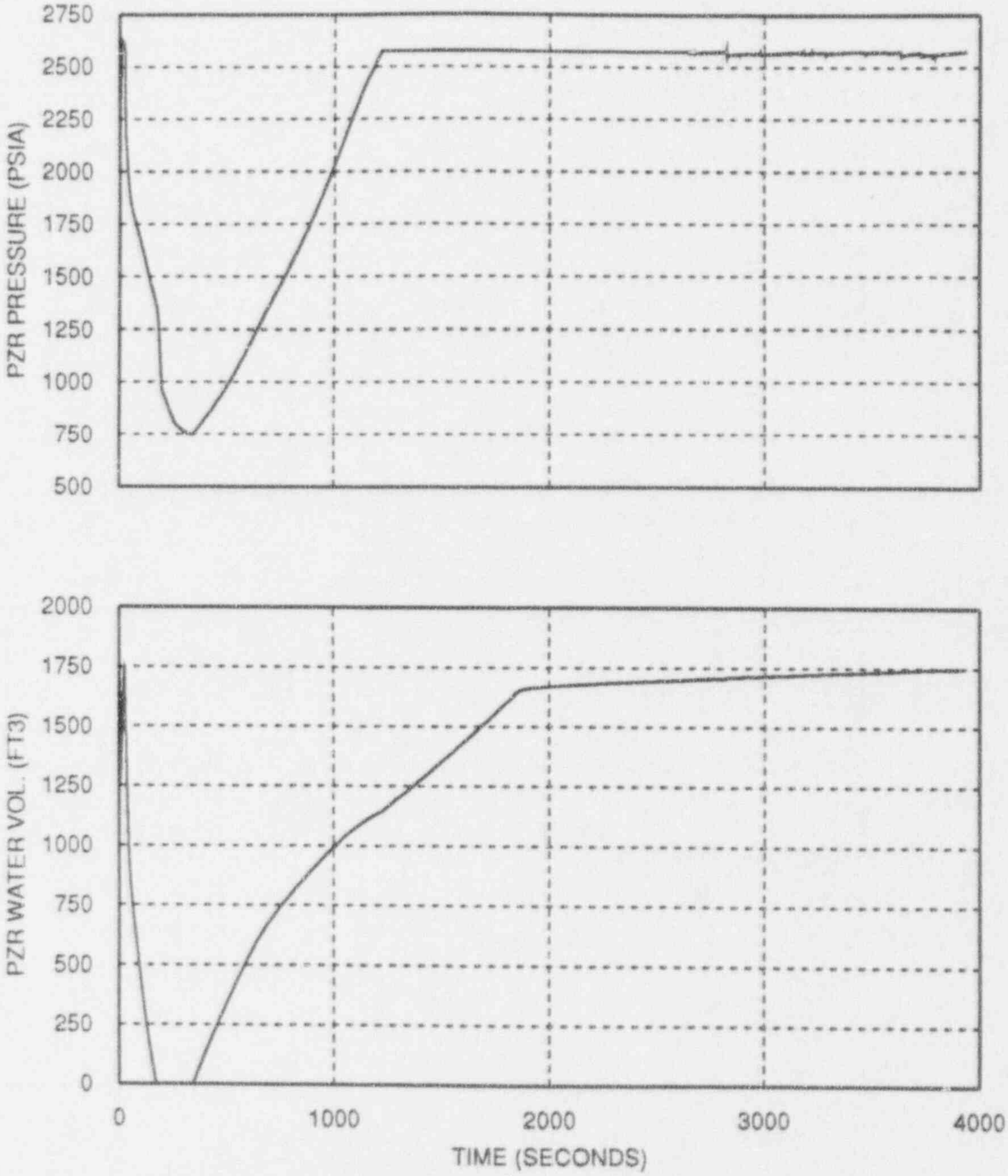
SEABROOK STATION	Loss of Normal Feedwater FIGURE 5.2-6 , Sh. 4



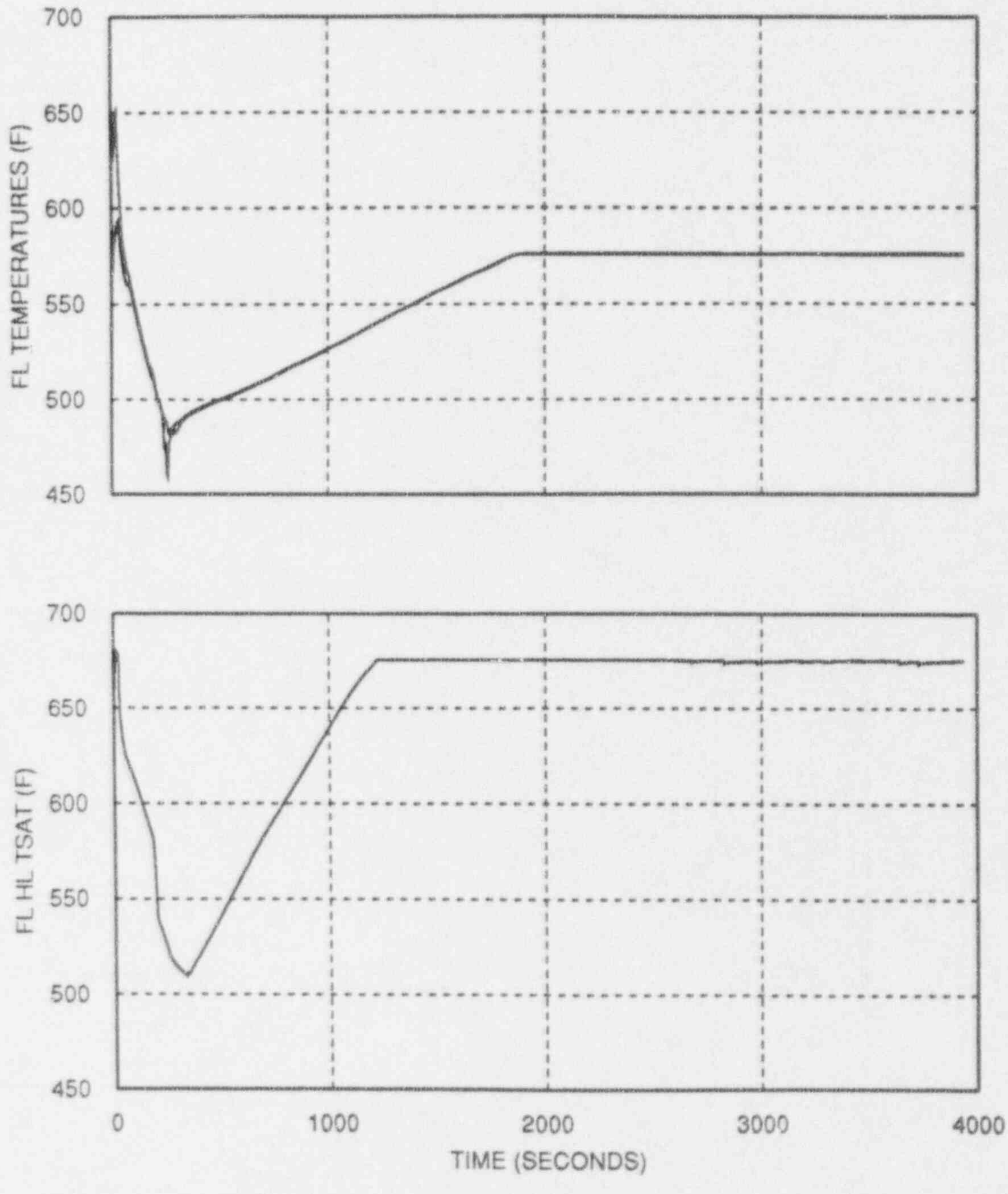
SEABROOK STATION	Loss of Normal Feedwater FIGURE 5.2-6, Sh. 5



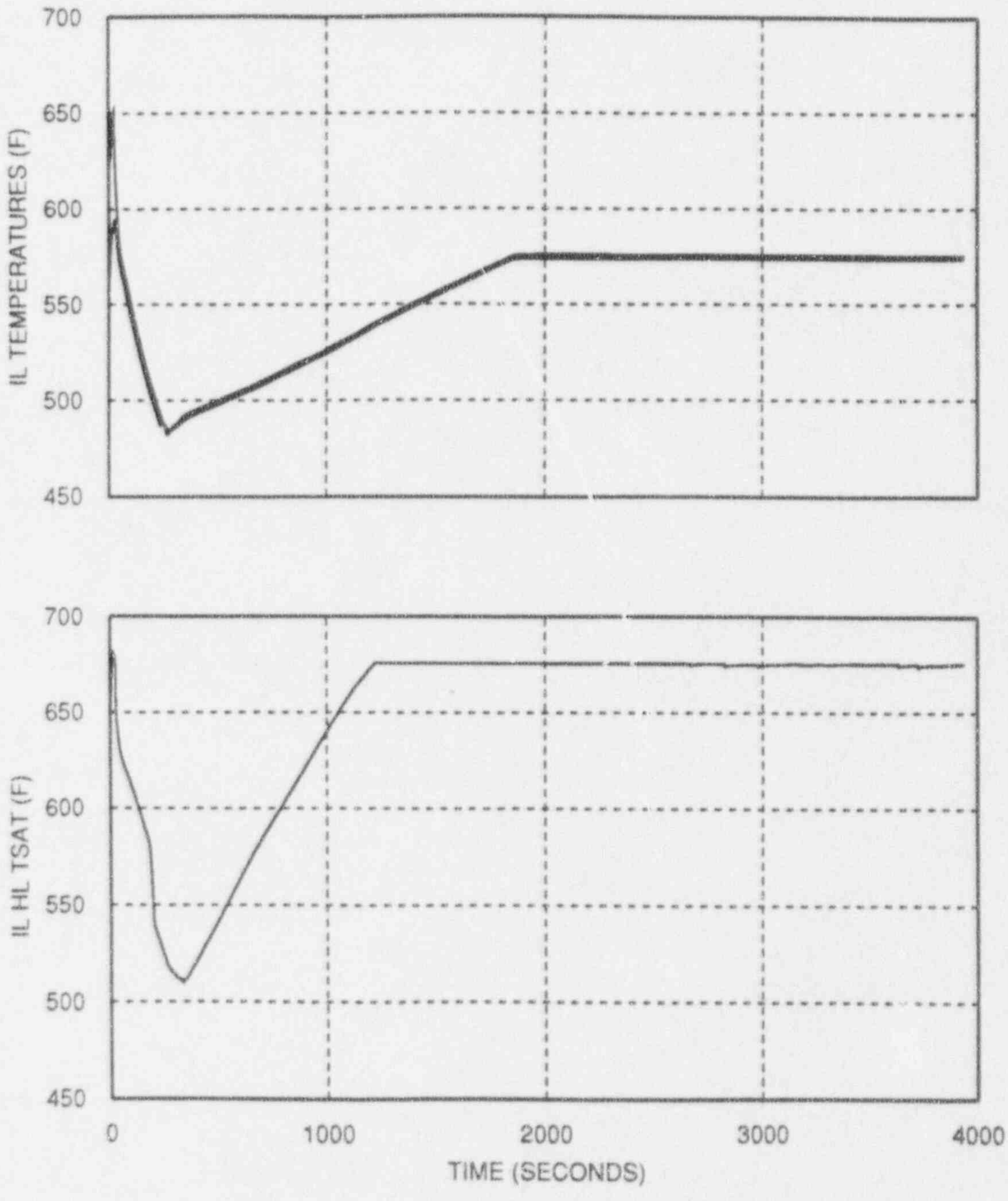
SEABROOK STATION	Normalized Nuclear Power and Total Core Reactivity Transients for Main Feedwater Line Rupture FIGURE 5.2-7, Sh 1



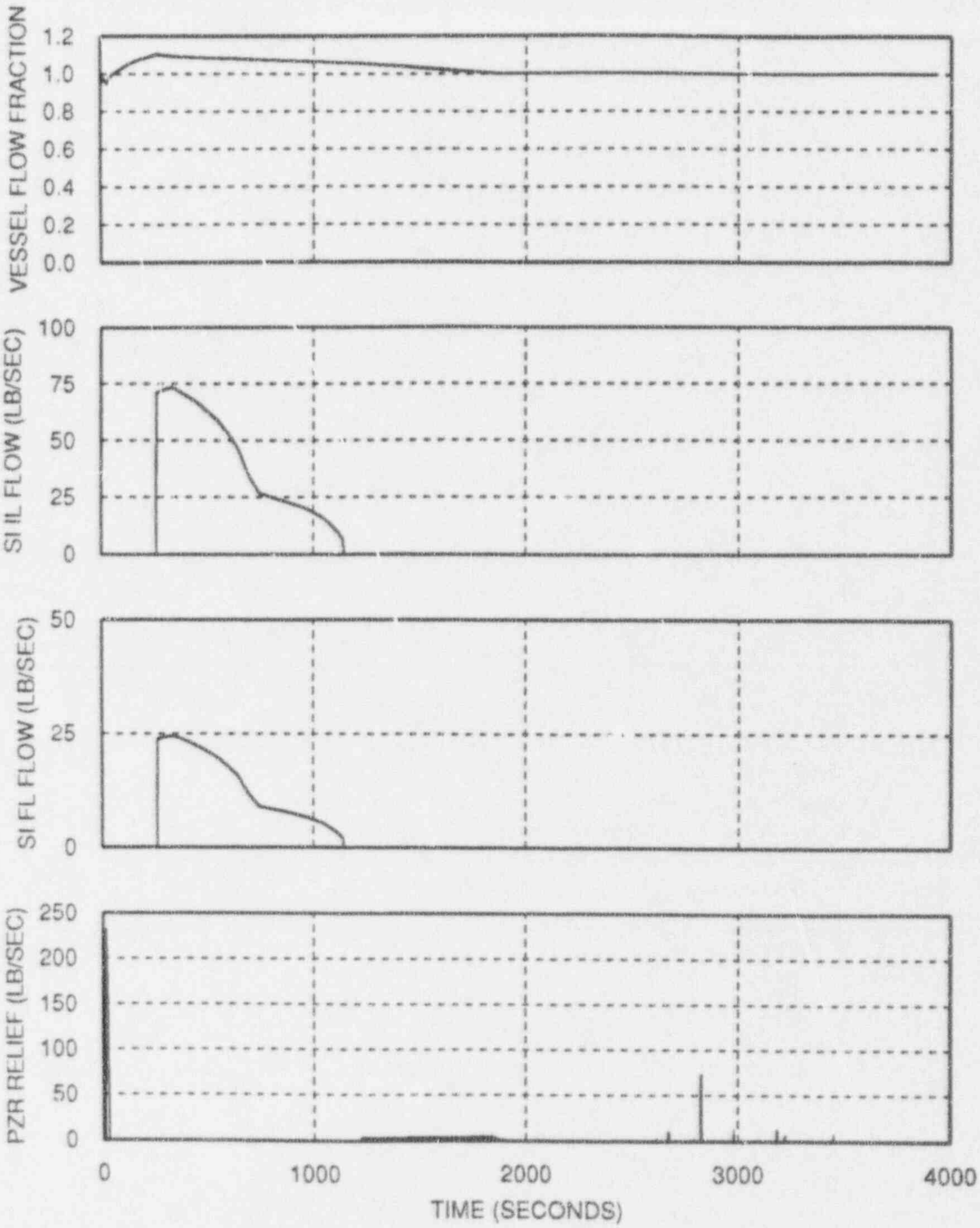
SEABROOK STATION	Pressurizer Pressure and Water Volume Transients for Main Feedwater Line Rupture FIGURE 5.2-7, Sh 2



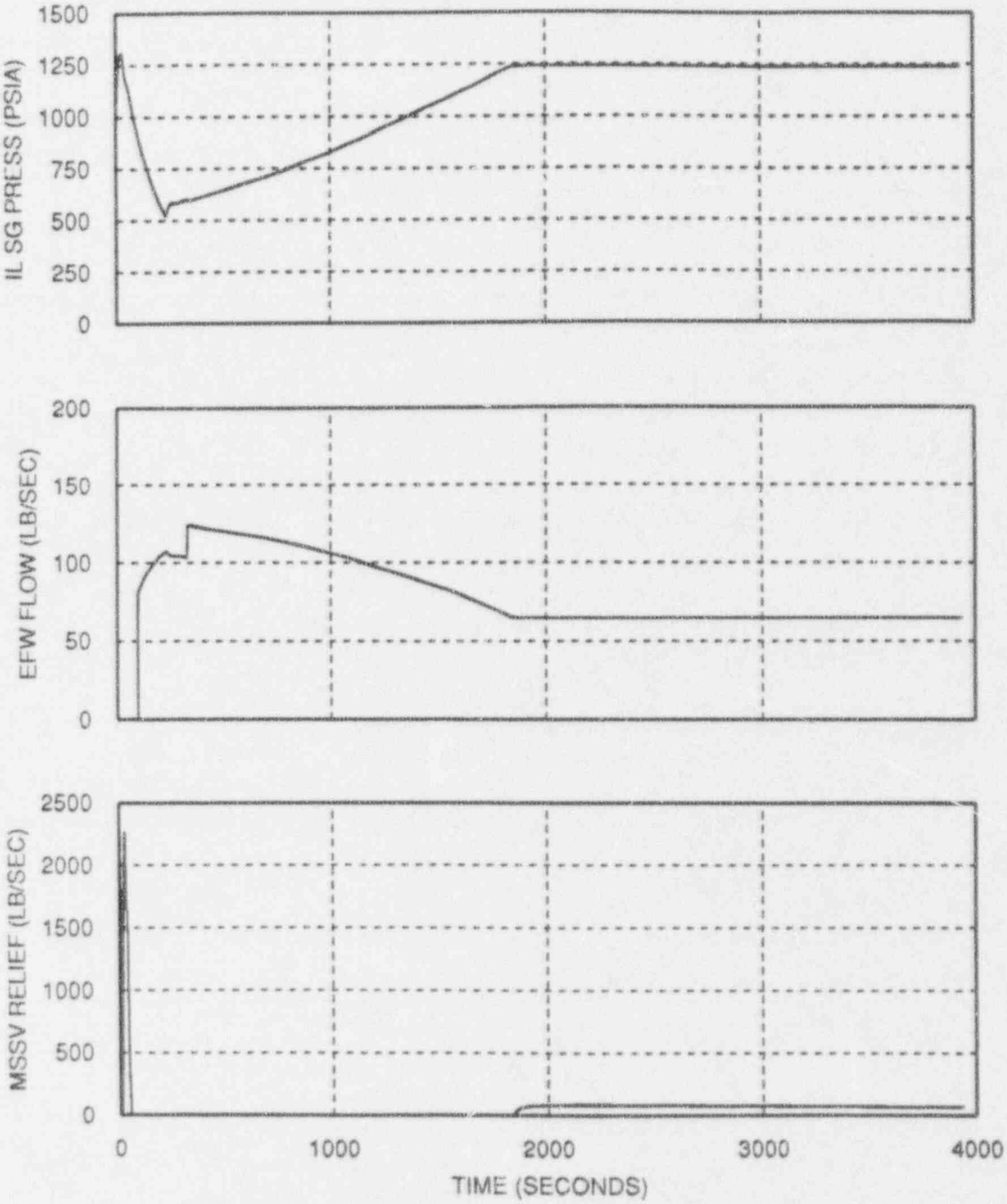
SEABROOK STATION	Faulted Loop Reactor Coolant Temperature Transients for Main Feedwater Line Rupture FIGURE 5.2-7, Sh 3



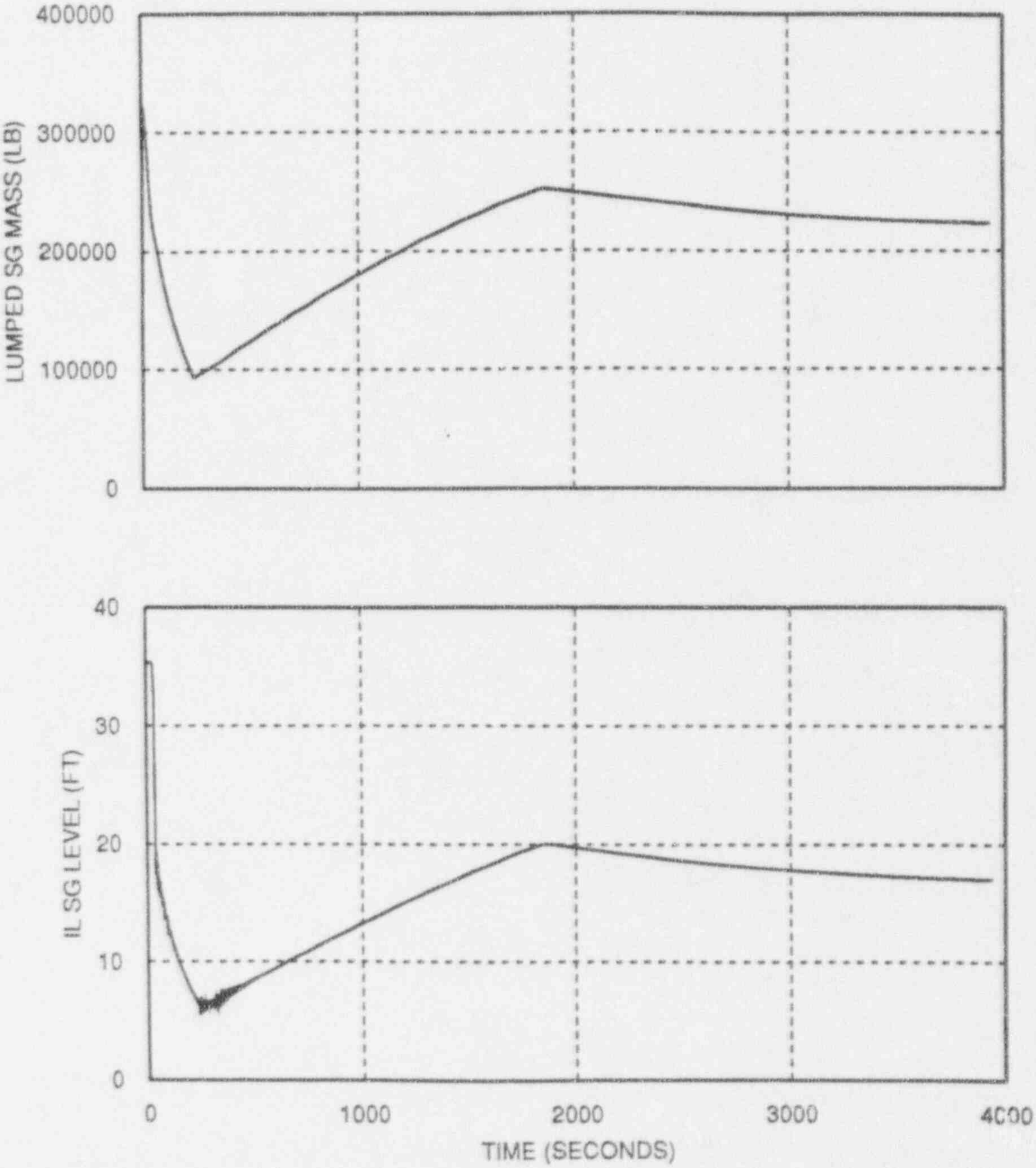
SEABROOK STATION	Intact Loops Reactor Coolant Temperature Transients for Main Feedwater Line Rupture FIGURE 5.2-7, Sh 4



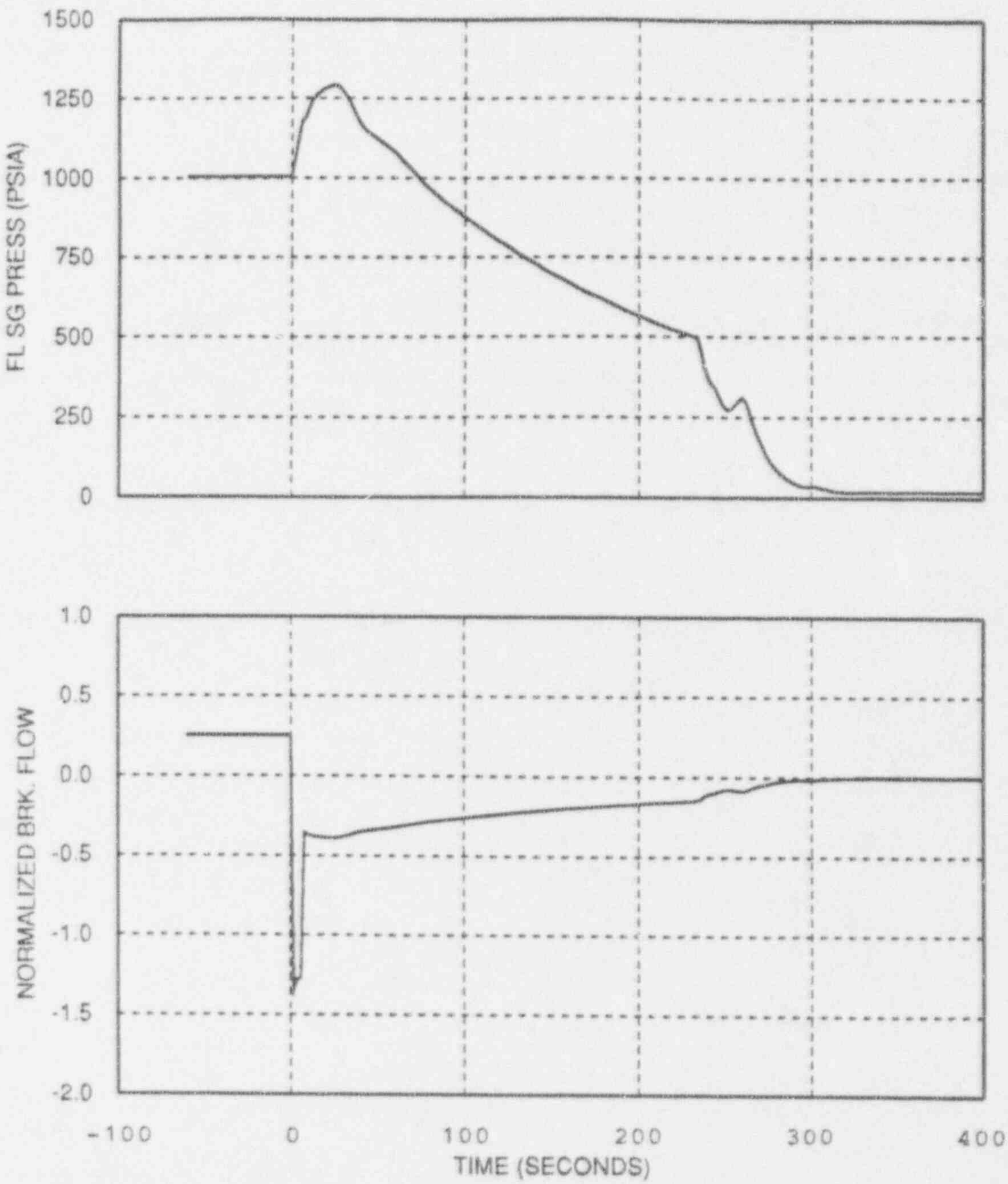
SEABROOK STATION	Vessel Mass Flow, Safety Injection Flow and Pressurizer Relief Transients for Main Feedwater Line Rupture FIGURE 5.2-8



SEABROOK STATION	Intact Loop Steam Generator Pressure, Emergency Feedwater Flow and Main Steam Safety Relief Transients for Main Feedwater Line Rupture FIGURE 5.2-9



SEABROOK STATION	Intact Loop Steam Generator Total Shell Mass and Straight Downcomer Level Transients for Main Feedwater Line Rupture FIGURE 5.2-10, Sh 1



SEABROOK STATION	Faulted Loop Steam Generator Shell Pressure and Feedwater Line Break Flow Transients for Main Feedwater Line Rupture FIGURE 5.2-10, Sh 2

5.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

A number of faults are postulated which could result in a decrease in Reactor Coolant System (RCS) flow rate. Detailed analyses are presented for the most limiting of these events:

a. Partial Loss of Forced Reactor Coolant Flow.

b. Complete Loss of Forced Reactor Coolant Flow.

c. Reactor Coolant Pump Shaft Seizure (Locked Rotor).

d. Reactor Coolant Pump Shaft Break.

Item a above is considered to be an ANS Condition II event, item b an ANS Condition III event, and items c and d ANS Condition IV events. Events a, b, and c were reanalyzed and results are presented in this section. Event d is bounded by event c.

5.3.1 Partial Loss of Forced Reactor Coolant Flow

5.3.1.1 Identification of Causes and Accident Description

A 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 pump or pumps supplied by a reactor coolant pump bus. 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 DNB with subsequent fuel damage if the reactor is not tripped promptly.

The plant design is such that the four reactor coolant pumps are supplied through two buses, two pumps per bus, connected to the generator. When a generator trip occurs, the generator breaker is tripped open, the buses are automatically supplied by an offsite power source, and the pumps will continue to supply coolant flow to the core. Following any turbine trip, there is immediate generator trip and automatic transfer of the buses to offsite power.

This event is classified as an ANS Condition II incident (an incident of moderate frequency).

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.

Above Permissive 8, low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive 7) and the power level corresponding to Permissive 8 (50 percent power) 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 P-7. These trips serve as a backup to the low flow trip.

5.3.1.2 Analysis of Effects and Consequences

a. Method of Analysis

One case has been analyzed: Loss of two pumps with four loops in operation. This transient is analyzed by four digital computer codes. First, the LOFTRAN[30] Code was used to calculate the loop and core flow during the transient and the time of reactor trip based on the calculated flows. The CHIC-KIN Code[23] was used to calculate the core average and hot channel heat flux transients based on the flow and time of reactor trip from LOFTRAN. The VIPRE Code[4] was used to calculate the DNBR during the transient based on the heat flux from CHIC-KIN and flow from LOFTRAN, using the WRB-1 correlation. The DNBR transients presented represent the minimum of the typical or thimble cell. Finally, the RETRAN Code[9] was used to perform a bounding pressure transient analysis. The analysis was performed to bound the pressure response to a complete loss of RCS flow as well as a partial loss of RCS flow. The pressure transient analysis assumed all four RCPs lose power and coastdown. The time of reactor trip was assumed to be the time of trip following a partial loss of flow in which two RCPs lose power, which occurs later than the time of trip following a complete loss of flow.

1. Initial Conditions

Initial operating conditions assumed for this event are consistent with the application of the Revised Thermal Design Procedure, i.e., minimum measured reactor coolant flow, nominal steady-state thermal power, nominal steady-state pressure, and nominal steady-state coolant average temperature.

2. Reactivity Coefficients

The most negative value of the Doppler defect is used. A conservatively high positive moderator temperature coefficient is assumed since this results in the maximum core power during the initial part of the transient when the minimum DNBR is reached.

3. Flow Coastdown

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, and is based on high estimates of system pressure losses.

b. Results

Figure 5.3-1 shows the transient response for the loss of two reactor coolant pumps with four loops in operation. The VIPRE analysis determined that the minimum DNBR for this event is bounded by the results shown for a complete loss of RCS flow in Section 5.3.2. Since DNB does not occur, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the average fuel and clad temperatures do not increase significantly above their respective initial values.

The calculated sequence of events is shown on Table 5.3-1. 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.

5.3.1.3 Radiological Consequences

The radiological consequences of this malfunction are bounded by the results presented in Subsection 5.3.2 (Complete Loss of Forced Reactor Coolant Flow).

5.3.1.4 Conclusions

The analysis shows that the DNBR will not decrease below the safety analysis limit value at any time during the transient. Thus, no fuel or clad damage is predicted, and all applicable acceptance criteria are met.

5.3.2 Complete Loss of Forced Reactor Coolant Flow

5.3.2.1 Identification of Causes and 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 DNB 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 supplied by an offsite power source, and the pumps will continue to supply coolant flow to the core. Following any turbine trip there is immediate generator trip and the buses continue to be powered by offsite power.

This event is classified as an ANS Condition III incident (an infrequent incident).

The following signals provide the necessary protection against a complete loss of flow accident:

a. Reactor coolant pump power supply undervoltage or underfrequency.

b. Low reactor coolant loop flow.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., loss of nonemergency AC power. 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. Reference 31 provides analyses of grid frequency disturbances and the resulting nuclear steam supply system protection requirements which are generally applicable to the Seabrook unit.

The reactor trip on low primary coolant loop flow is provided to protect against loss of flow conditions which affect only one reactor coolant loop. This function is generated by two out of three low flow signals per reactor coolant loop. Above Permissive 8, low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive 7) and

the power level corresponding to 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 this trip function will protect the core from underfrequency events. This effect is fully described in Reference 31.

5.3.2.2 Analysis of Effects and Consequences

a. Method of Analysis

The complete loss of flow transient is analyzed by three digital computer codes. First, the RETRAN[9] Code 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 CHIC-KIN[23] Code is then used to calculate the heat flux transient based on the nuclear power and flow from RETRAN. Finally, the VIPRE Code[4] is used to calculate the DNBR during the transient based on the heat flux from CHIC-KIN and flow from RETRAN.

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Subsection 5.3.1, except that following the loss of power supply to all pumps at power, a reactor trip is actuated by either reactor coolant pump power supply undervoltage or underfrequency.

The normalized reactivity versus rod position assumed in the analysis considered a slightly bottom skewed shape for evaluating DNB as discussed in Section 5.0. A rod drop time of 2.4 seconds to dashpot entry is assumed in the analysis of the complete loss of forced reactor coolant flow.

b. Results

Figures 5.3-2 through 5.3-4 show the transient response for the loss of power to all reactor coolant pumps with four loops in operation. The reactor is assumed to be tripped on an undervoltage signal. Figure 5.3-4 shows the DNBR to be always greater than the safety analysis limit value. Since DNB does not occur, the ability of the primary coolant to remove heat from the fuel rod is not greatly reduced. Thus, the average fuel and clad temperatures do not increase significantly above their respective initial values.

The calculated sequence of events for the case analyzed is shown on Table 5.3-1. The reactor coolant pumps will continue to coast down, and natural circulation flow will eventually be established, as demonstrated in Subsection 5.2.6. Following the complete loss

of forced reactor coolant flow and the loss of nonemergency AC power, the natural circulation conditions will be essentially the same.

The loss of nonemergency AC power is analyzed to emphasize long- term heat removal under natural circulation conditions. To maximize RCS stored energy and minimize steam generator heat removal, the loss of power to the reactor coolant pumps is delayed until the low-low steam generator level setpoint is reached. These assumptions for natural circulation are conservative with respect to the natural circulation conditions achieved if the pumps coast down immediately. Therefore, the analysis presented in Subsection 5.2.6 bounds the natural circulation conditions of Subsection 5.3.2. With the reactor tripped, a stable plant condition would be attained. Normal plant shutdown may then proceed.

5.3.2.3 Radiological Consequences

No radiological consequences have been calculated for this postulated accident since no fuel or clad damage is predicted.

5.3.2.4 Conclusions

The analysis performed has demonstrated that for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the safety analysis limit value at any time during the transient. Thus, no fuel or clad damage is predicted, and all applicable acceptance criteria are met.

5.3.3 Reactor Coolant Pump Shaft Seizure (Locked Rotor)

5.3.3.1 Identification of Causes and Accident Description

The accident postulated 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.

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. 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 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, their pressure reducing effect as well as the pressure reducing effect of the spray is not included in the analysis.

This event is classified as an ANS Condition IV incident (a limiting fault).

5.3.3.2 Analysis of Effects and Consequences

a. Method of Analysis

Three digital computer codes are used to analyze this transient. The RETRAN[9] Code is used to calculate the resulting loop and core flow transients following the pump seizure, the time of reactor trip based on the loop flow transients, and to determine the peak pressure. The nuclear power and the thermal behavior of the fuel located at the core hot spot are investigated using the CHIC-KIN[23] Code, which uses the core flow calculated by RETRAN. The VIPRE code[4] is used to evaluate the DNBR using the core flow from RETRAN and the normalized power from CHIC-KIN.

At the beginning of the postulated locked rotor accident, i.e., at the time the shaft in one of the reactor coolant pumps is assumed to seize, the plant is assumed to be in operation under the most adverse steady-state operating conditions for determining peak RCS pressure. The conditions are: maximum guaranteed steady-state thermal power; maximum steady-state pressure, and maximum steady-state coolant average temperature. The minimum DNBR is evaluated using nominal operating conditions, consistent with the use of RTDP. For RTDP, uncertainties on operating conditions are included in the safety analysis DNBR limit[4].

1. Evaluation of the Pressure Transient

The initial pressure is conservatively estimated as 50 psi above nominal pressure (2250 psia) to allow for errors in the pressurizer pressure measurement and control channels. After pump seizure, the neutron flux is rapidly reduced by control rod insertion. Rod motion is assumed to begin one second after the flow in the affected loop reaches 87 percent of nominal flow. No credit is taken for the pressure reducing effect of the pressurizer relief valves, pressurizer spray, steam dump or controlled feedwater flow after plant trip.

Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effect.

2. <u>Evaluation of DNB in the Core During the Accident</u>

For this accident, DNB is assumed to occur in the core, and therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this "hot spot" condition represent the upper limit with respect to clad temperature and zirconium-water reaction.

In the evaluation, the rod power at the hot spot is based on the average core power versus time and axial and radial peaking that are conservative with respect to the limiting flux profiles at the edge of the allowable axial flux difference (ΔI) band.

For this analysis, the initial values of the pressure and core inlet temperature are used throughout the transient since they are the most conservative with respect to clad temperature response. For conservatism, peak fuel temperatures are determined assuming that DNB occurs at the start of the transient.

A range of heat transfer coefficients between the fuel and clad (gap coefficient) up to 10,000 BTU/hr-ft^2-^{o}F were investigated. Gap conductances which maximized fuel and clad temperatures were used.

b. <u>Results</u>

The peak reactor coolant system pressure and the peak clad surface temperature are bounded by the results of the locked rotor event followed by a loss of offsite power (Section 5.3.4)

The calculated sequence of events for the case analyzed is shown on Table 5.3-1. Figure 5.3-5 shows that the core flow rapidly reaches a new equilibrium value. The peak RCS pressure observed during a locked rotor or shaft break in a reactor coolant pump is well below 110 percent of design pressure (2750 psia). During the short time that the RCS pressure is high enough to open the pressurizer safety valves, the relief rate was within the maximum capacity of the safety valves. Thus, a loss of function of the RCS will not occur. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

5.3.3.3 Radiological Consequences

Input parameters and assumptions used in the radiological consequence analysis of this event have not changed from those used in the previous analysis shown in the UFSAR. Previous UFSAR results remain applicable.

5.3.3.4 Conclusions

a. Since the peak reactor coolant system pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the Primary Coolant System is not endangered.

b. Since the peak clad surface temperature calculated for the hot spot during the worst transient remains considerably less than 2700°F, the core will remain in place and intact with no loss of core cooling capability.

c. The doses which have been calculated for the locked rotor accident are below the values which are a small fraction of 10 CFR Part 100 guidelines.

5.3.4 Reactor Coolant Pump Shaft Seizure (Locked Rotor) Followed by Loss of Offsite Power

5.3.4.1 Identification of Causes and Accident Description

The transient presented here is the most limiting for the locked rotor and shaft break accidents in terms of peak clad temperature, maximum reactor coolant pressure and radiological consequences.

In the event of a locked rotor/shaft break of a reactor coolant pump (RCP), the remaining three RCPs will continue to run. Analysis of the breaker coordination shows the following: under all postulated operating conditions, including maximum load of one of the 13.8 kV buses (2 RCPS, 2 circulating water pumps and the 13.8 kV substations) and minimum bus voltage, failure of one RCP (with incipient locked rotor amps) will not result in tripping of the incoming breaker to the 13.8 kV bus. Because of the separate power supply to the other 13.8 kV bus (see UFSAR Figure 8.3-1), this event will have no effect on the power supply of this bus.

Offsite power will not be lost as a consequence of the event. UFSAR Subsection 8.2.2.3 provides the results of stability studies showing that the loss of one or both of the Seabrook Units would not cause a loss of offsite power. UFSAR Figure 8.3-1 is a one-line

diagram of the Electrical Distribution System showing the generator circuit breaker used for isolating the generator without affecting the normal supply to the 13.8 kV bus.

Nevertheless, a bounding evaluation of a locked rotor, followed by a loss of offsite power, is provided below. The transient is postulated to occur in the following manner:

a. RCP rotor locks (or shears) and flow in that loop begins to coastdown.

b. The reactor is tripped on low RCS flow in one loop.

c. Turbine-generator trips.

d. Offsite power is lost even though grid stability analyses show it will not be lost.

e. The loss of offsite power causes the three remaining RCPs to coast down.

5.3.4.2 Analysis of Effects and Components

a. Method of Analysis

The method of analysis used is the same as presented in Subsection 5.3.3. A bounding value of maximum reactor coolant pressure is calculated by assuming offsite power is lost one second after turbine trip. This assumption is conservative because grid stability analyses show offsite power will not be lost.

b. Results

The results for the case analyzed are summarized in Table 5.3-2. The calculated sequence of events assuming consequential loss of offsite power is shown in Table 5.3-3. The results of temperature, flow, heat flux and clad temperature are shown in Figure 5.3-6. These may be compared with the results of the transient shown in Subsection 5.3.3. The case without offsite power results in higher clad temperature and RCS pressure. This reflects the effect of reduced flow due to the loss of power since the peak values occur after the coastdown begins.

The worst single failure for this event is a loss of one protection train. This failure has no impact on peak clad temperatures or maximum reactor coolant pressure since there are two trains.

5.3.4.3 Radiological Consequences

Assuming that all fuel rods with a minimum transient DNBR of less than the safety analysis limit become failed rods, then the fraction of failed fuel is predicted to be less than 8 percent for this bounding event.

In the event of a failed open atmospheric steam dump valve, the offsite doses are well within the design limits specified in 10 CFR Part 100. The offsite thyroid doses, in the event of a failed open valve concurrent with the locked rotor event plus the assumed 8 percent fuel clad failure and the assumed loss of offsite power, are a maximum of 100 times the values presented in Updated FSAR Subsection 15.3.3.3, or 230 rems and 240 rems at the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ), respectively. The offsite whole body gamma doses for this event are 1.4 rem and 1.9 rem at the EAB and LPZ, respectively.

With the failure of a steam dump valve in the open position, plant procedure would call for isolation of the affected steam generator's feedwater flow with subsequent drying out of the steam generator and loss of any iodine partitioning afforded by the water volume contained above the point of primary to secondary leakage. Although some finite period of time is required for the considerable amount of water contained within a typical Westinghouse steam generator to boil off, it has been conservatively assumed that this time is small and no partitioning of iodine occurs within the steam generator.

The failure of an atmospheric steam dump valve, discussed above, is considered to be the limiting single failure for radiological dose evaluations associated with the locked rotor event. In addition to the sequence of events mentioned above, it is also conservatively assumed that the entire primary to secondary allowable leakage of 1 gpm occurs in the steam generator that is venting through the stuck open valve.

5.3.4.4 Conclusion

The transient presented here is the most limiting for the locked rotor and shaft break accidents in terms of peak clad temperature and maximum reactor coolant pressure. Since the peak RCS pressure reached is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the Primary Coolant System is not endangered. Also, the maximum peak clad surface temperature calculated for the hot spot remains considerably less than 2700°F; this ensures that the core will remain in place and intact with no loss of core cooling capability. As in the locked rotor analysis discussed in Subsection 5.3.3, this analysis conservatively assumes that DNB occurs at the beginning of the transient.

Grid stability analyses show that offsite power will not be lost following a turbine trip. However, a conservative radiological dose calculation was performed assuming offsite power is lost 2.8 seconds after turbine trip and assuming the entire primary to secondary allowable leakage of 1 gpm occurs in a steam generator that is venting through a stuck-open atmospheric dump valve. The offsite doses are less than the 10 CFR Part 100 guidelines values.

5.3.5 Reactor Coolant Pump Shaft Break

This accident is postulated as the instantaneous failure of a reactor coolant pump shaft. Flow through the affected loop is rapidly reduced, similar to the locked rotor transient discussed in Sections 5.3.3 and 5.3.4, except that the rotor is free to spin in the reverse direction. The core flow coastdown and peak RCS pressure were evaluated similar to the locked rotor transient. The locked rotor transient was found to have a more rapid coastdown in core flow prior to the reactor trip on low flow. Therefore, the peak RCS pressure, peak fuel and clad temperatures, and number of failed fuel rods are bounded by the results of the locked rotor transient discussed in Sections 5.3.3 and 5.3.4.

TABLE 5.3-1

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN A DECREASE IN REACTOR COOLANT SYSTEM FLOW

Accident	Event	Time (seconds)
Partial Loss of Forced Reactor Coolant Flow	Two of four operating pumps begin coasting down	0
	Low flow reactor trip	1.6
	Rods begin to drop	2.6
	Minimum DNBR occurs	3.9
Complete Loss of Forced Reactor Coolant Flow	All operating pumps lose power and begin coasting down	0
	Reactor coolant pump undervoltage trip point reached	0
	Rods begin to drop	1.5
	Minimum DNBR occurs	3.1
Reactor Coolant Pump Shaft Seizure (Locked Rotor)	Rotor on one pump locks	0
	Low flow trip point reached	0.15
	Rods begin to drop	1.15
	Maximum clad temperature occurs	2.80
	Maximum RCS pressure occurs	4.00

TABLE 5.3-2

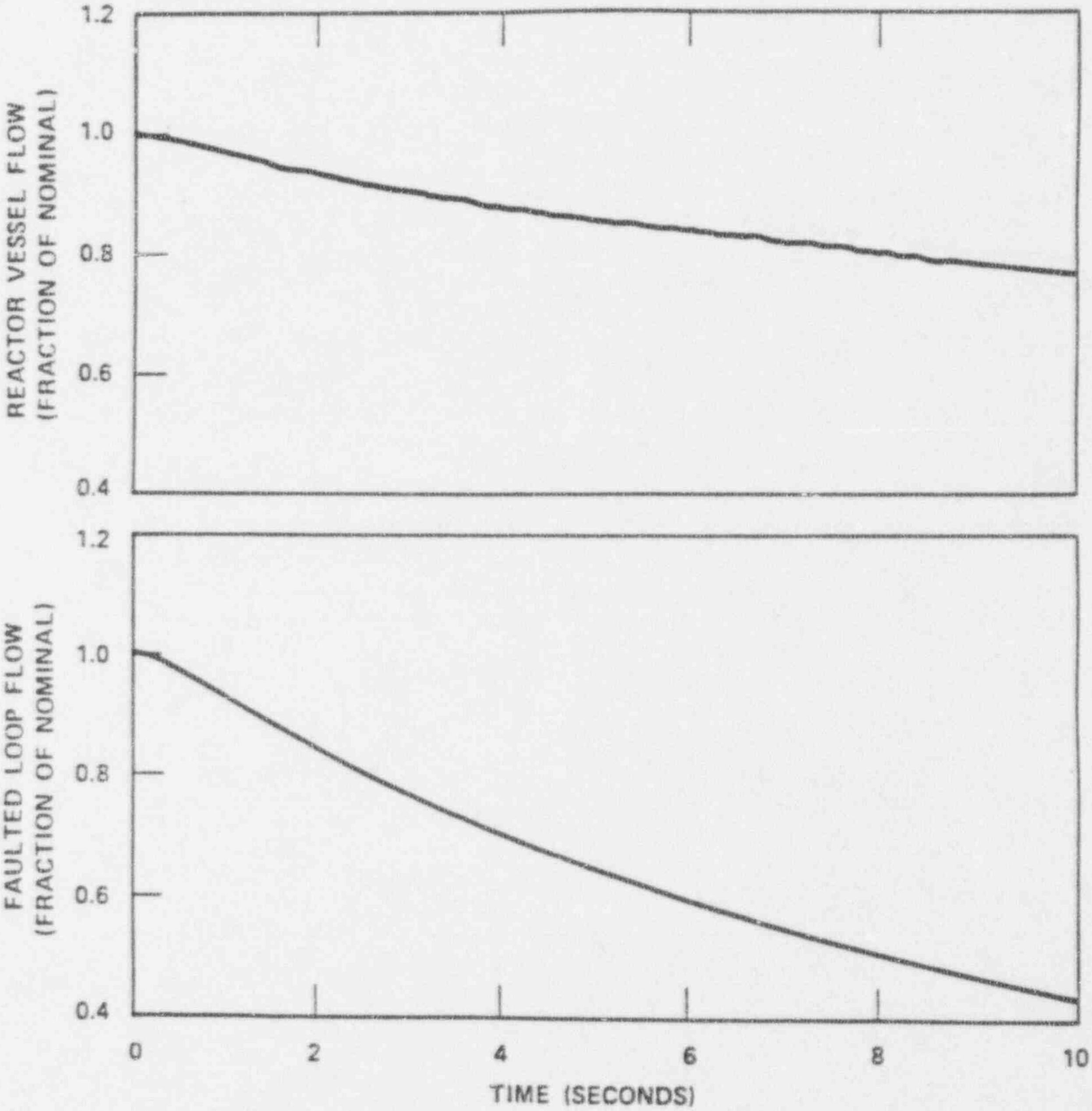
SUMMARY OF RESULTS FOR LOCKED ROTOR TRANSIENT WITHOUT OFFSITE POWER

Maximum Reactor Coolant System Pressure (psia)	2604
Maximum Cladding Temperature (^{o}F) Core Hot Spot	1104

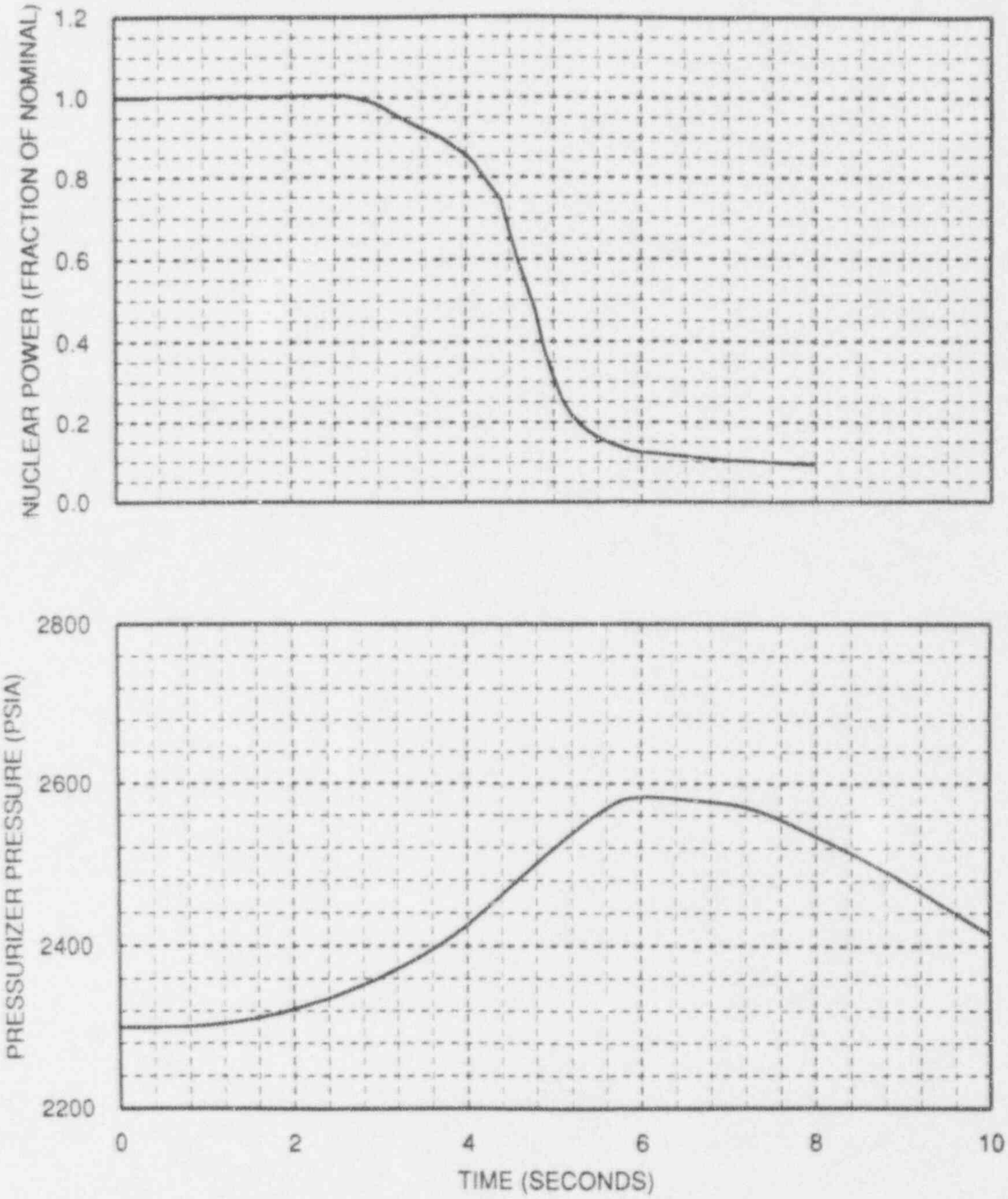
TABLE 5.3-3

SEQUENCE OF EVENTS
LOCKED ROTOR WITHOUT OFFSITE POWER

Event	Time (seconds)
Rotor on one pump locks	0.0
Low RCS flow trip setpoint reached	0.15
Rods begin to drop	1.15
Remaining reactor coolant pumps begin to coast down	2.15
Maximum clad temperature occurs	2.80
Maximum RCS pressure occurs	4.65



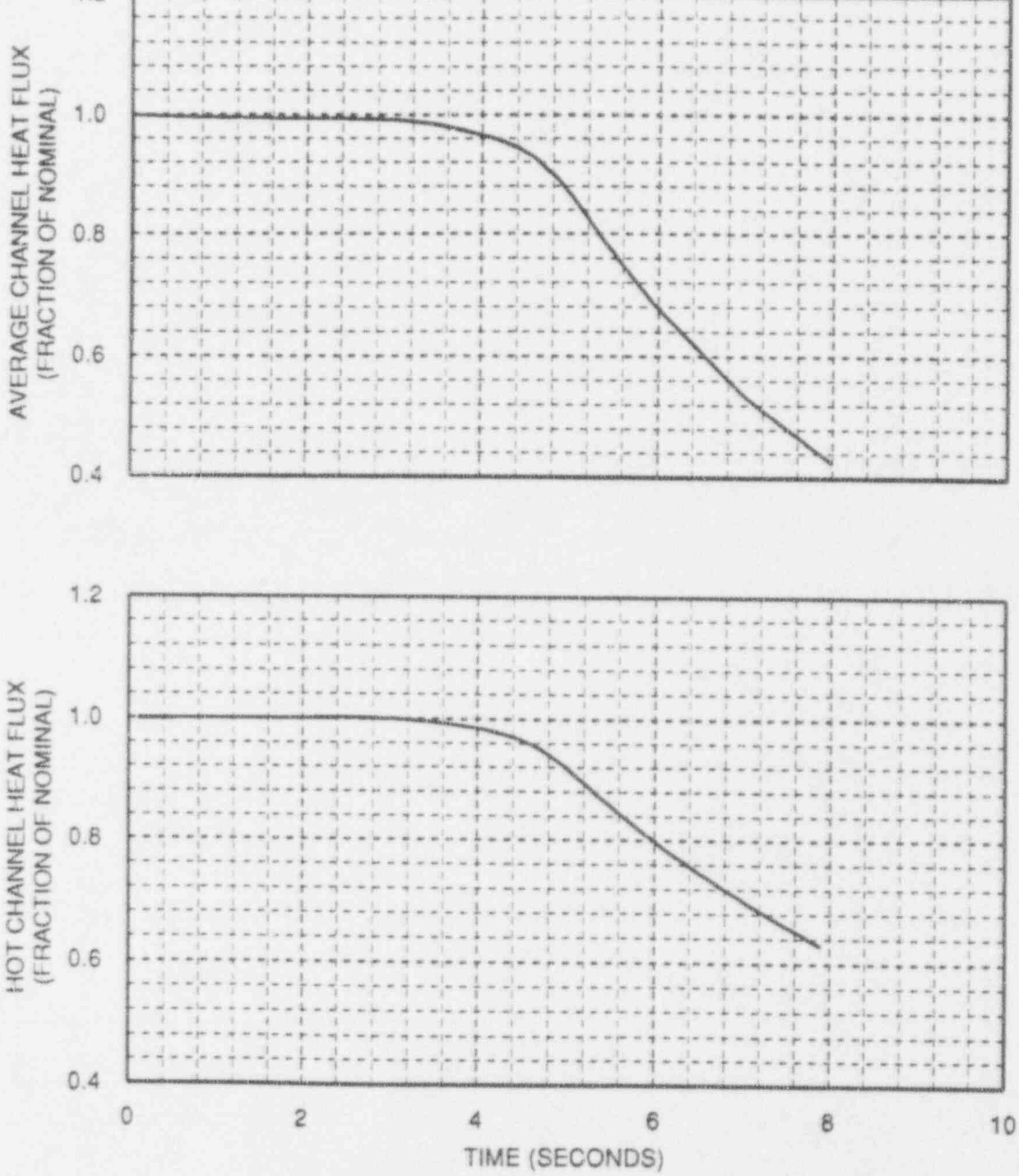
SEABROOK STATION	Four Loops in Operation, Two Pumps Coasting Down	
		FIGURE 5.3-1, Sh. 1



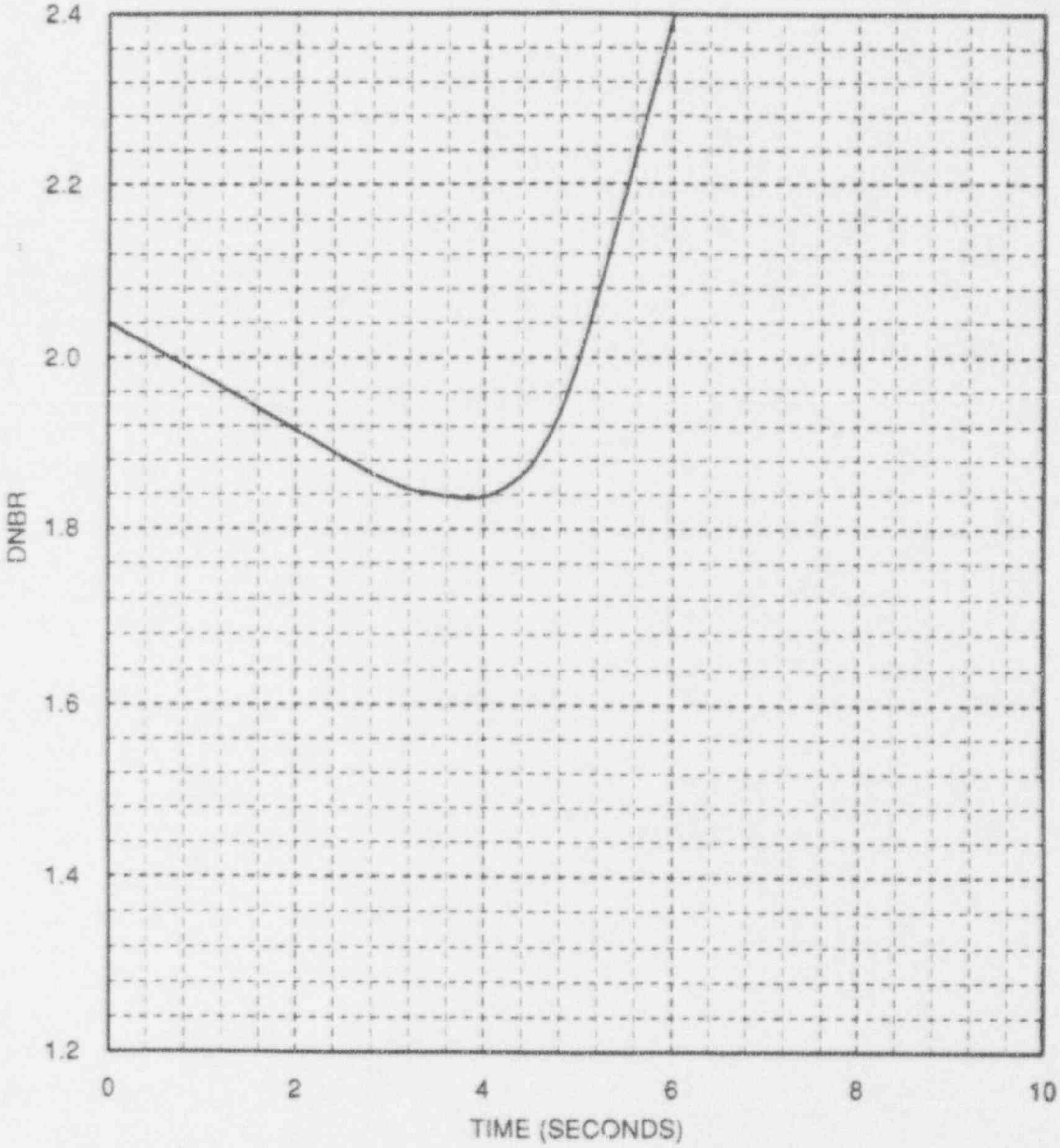
SEABROOK STATION

Four Loops in Operation, Two Pumps Coasting Down

FIGURE 5.3-1 , Sh. 2



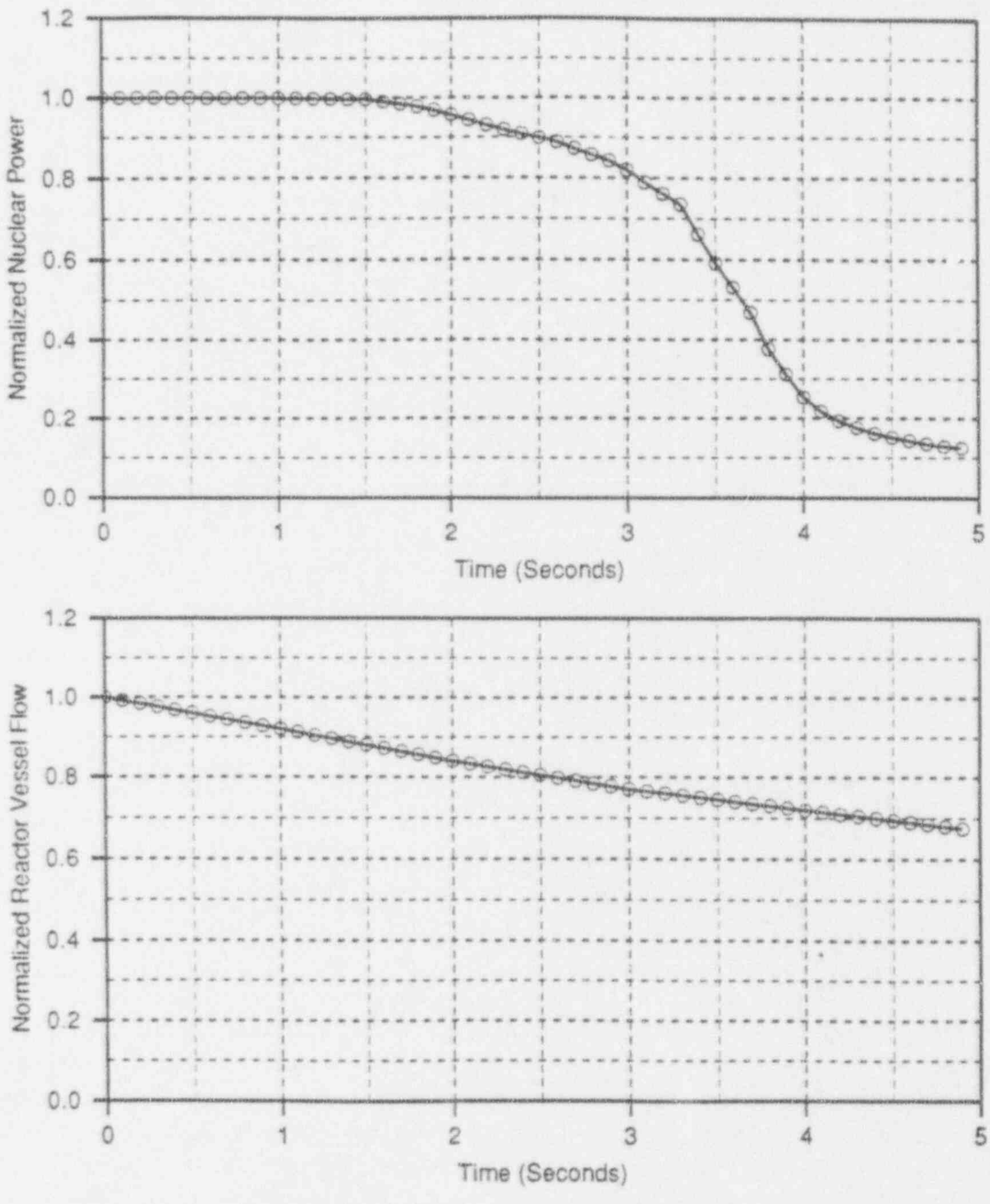
SEABROOK STATION	Four Loops in Operation, Two Pumps Coasting Down FIGURE 5.3-1 , Sh. 3



SEABROOK STATION

DNBR Versus Time for Four Loops in Operation, Two Pumps Coasting Down

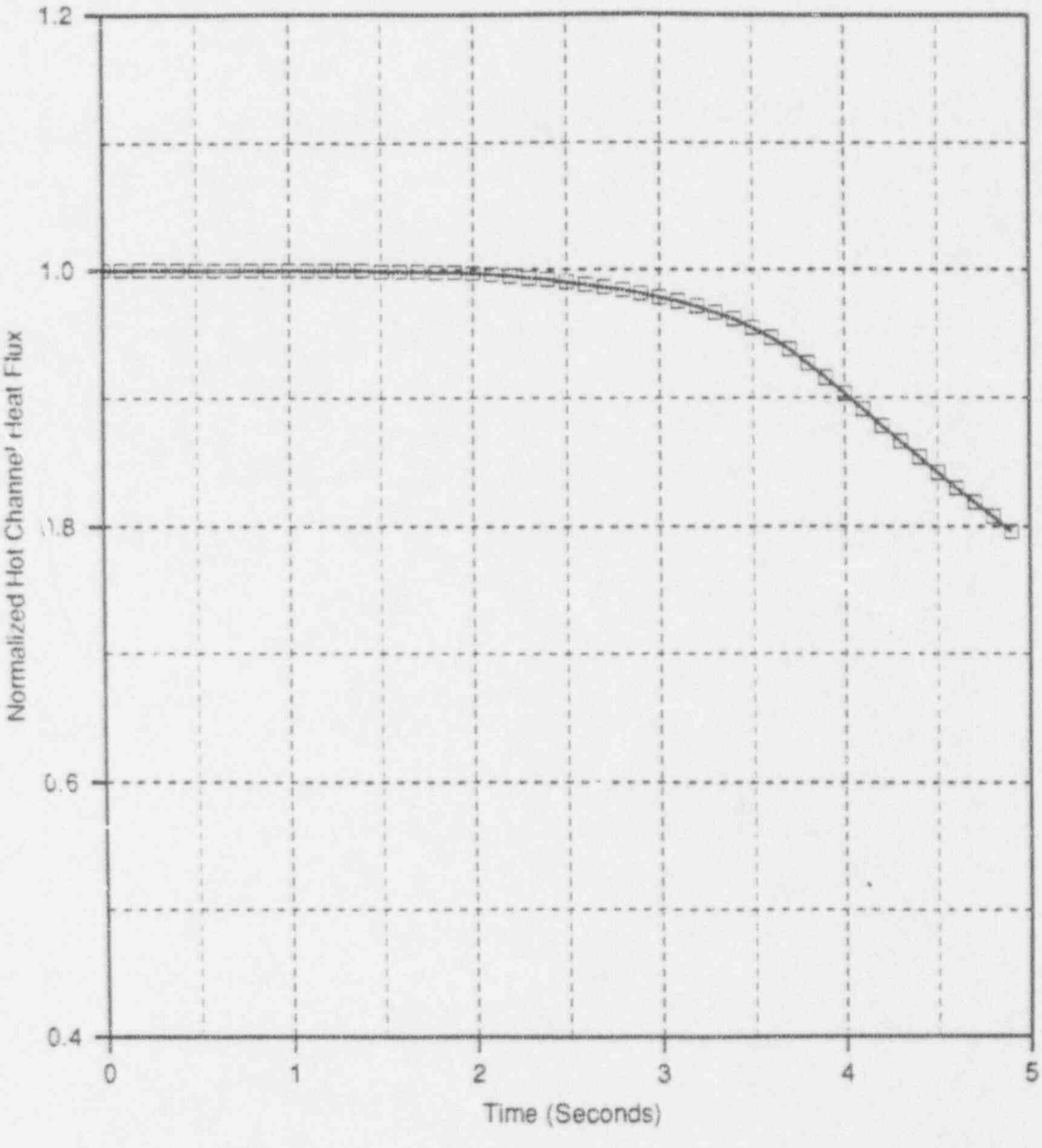
FIGURE 5.3-1, Sh. 4



SEABROOK STATION

Four Loops In Operation, Four Pumps Coasting Down

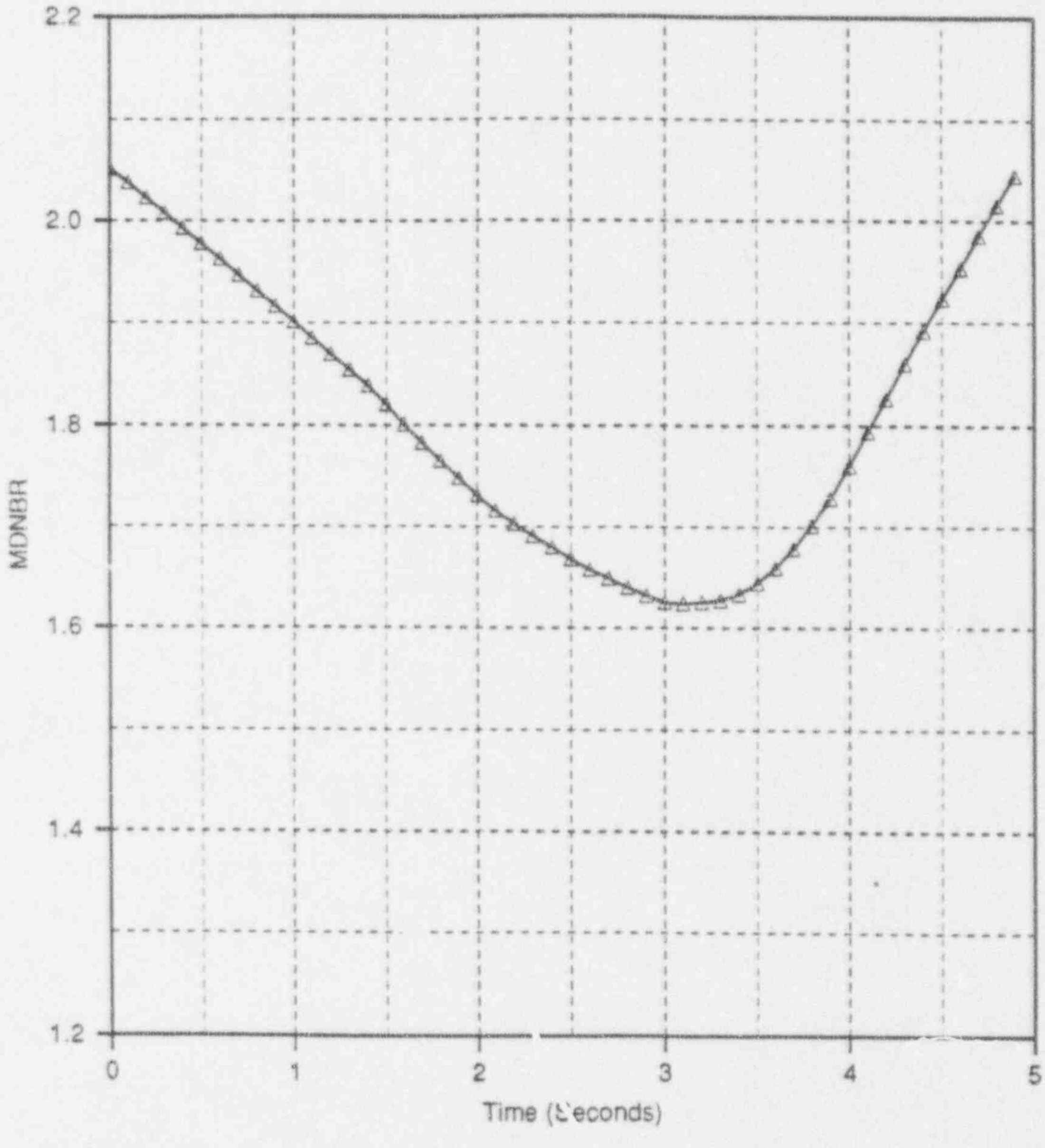
FIGURE 5.3- 2



SEABROOK STATION

Four Loops In Operation, Four Pumps Coasting Down

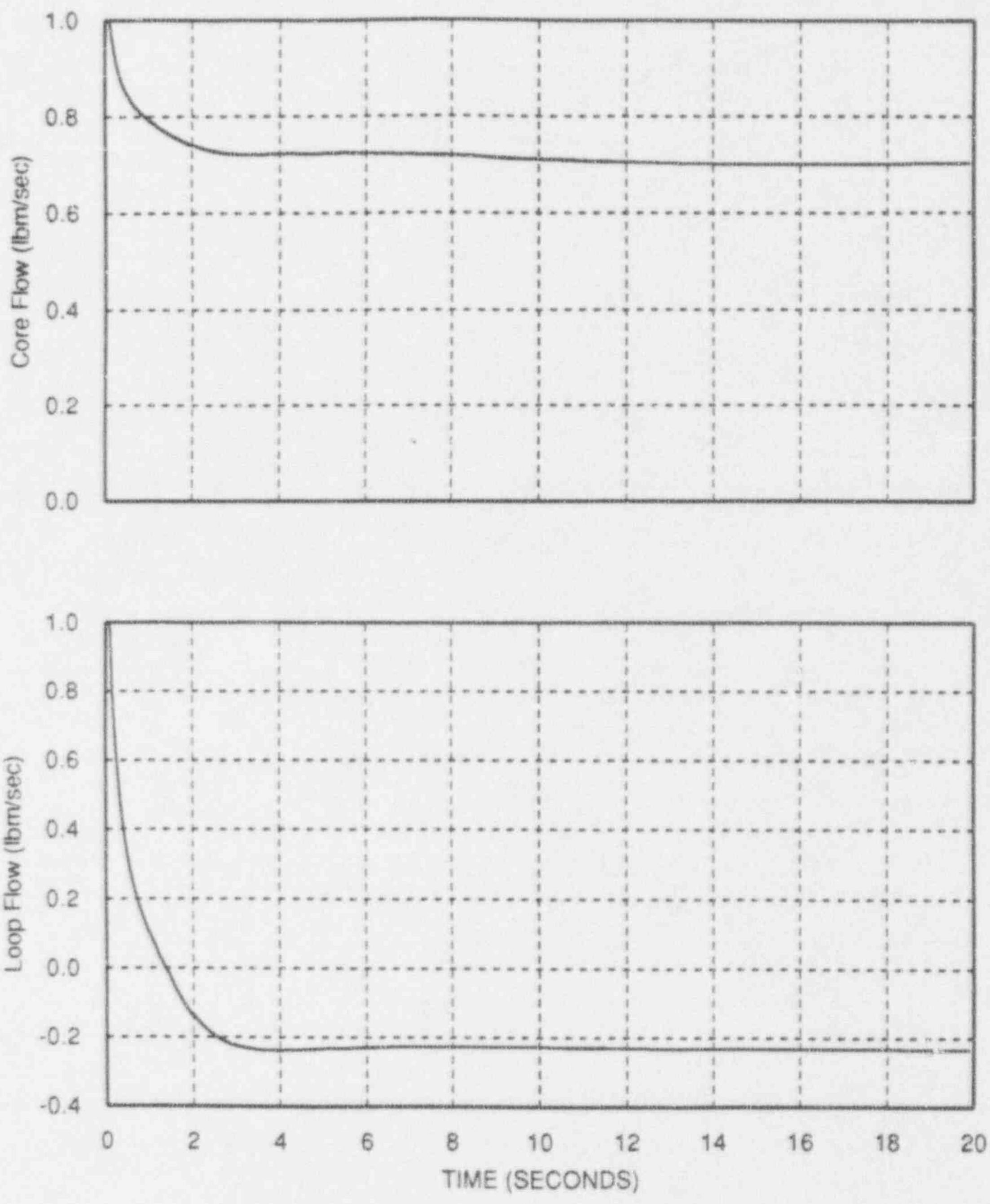
FIGURE 5.3- 3



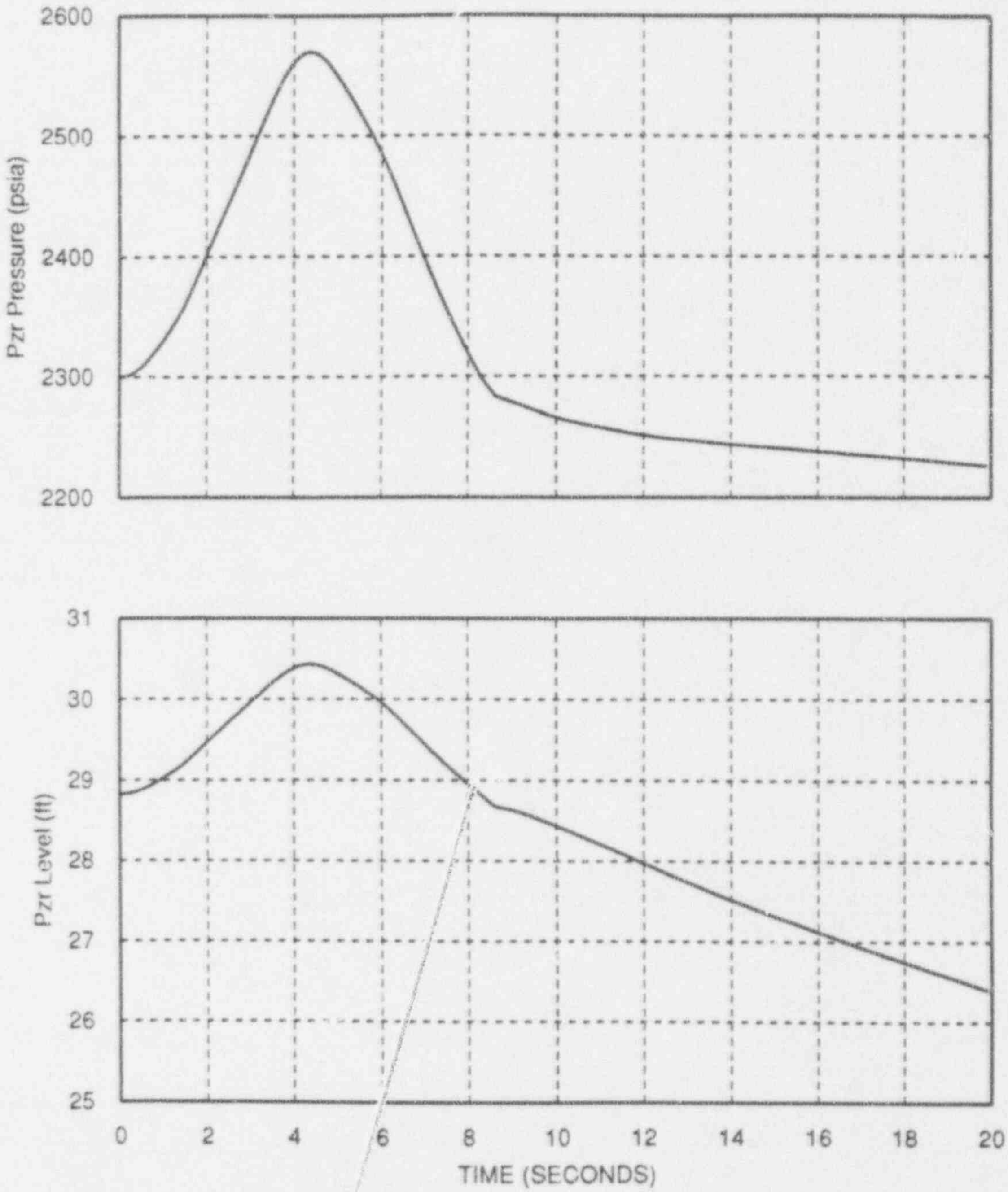
SEABROOK STATION

Four Loops In Operation, Four Pumps Coasting Down

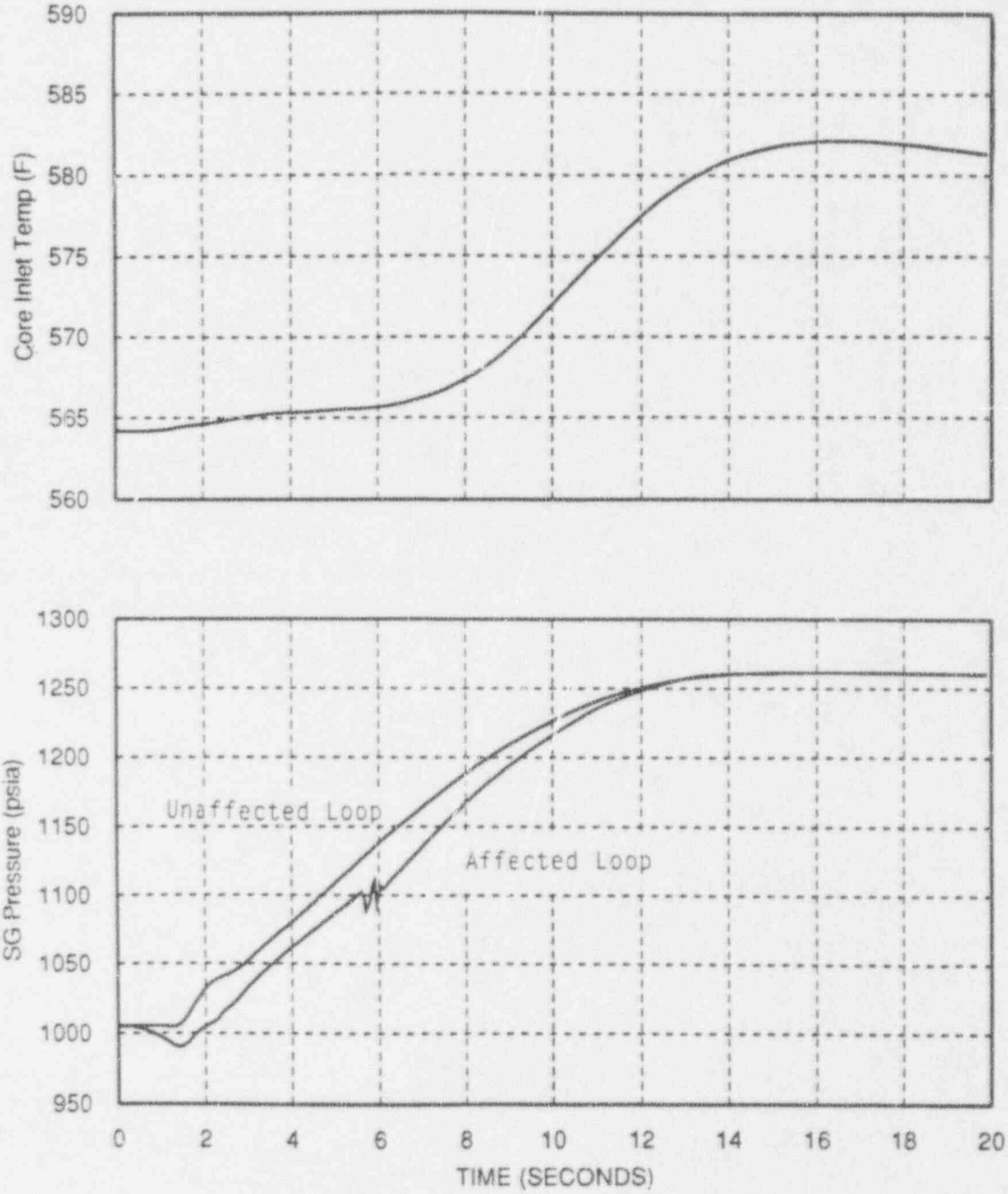
FIGURE 5.3-4



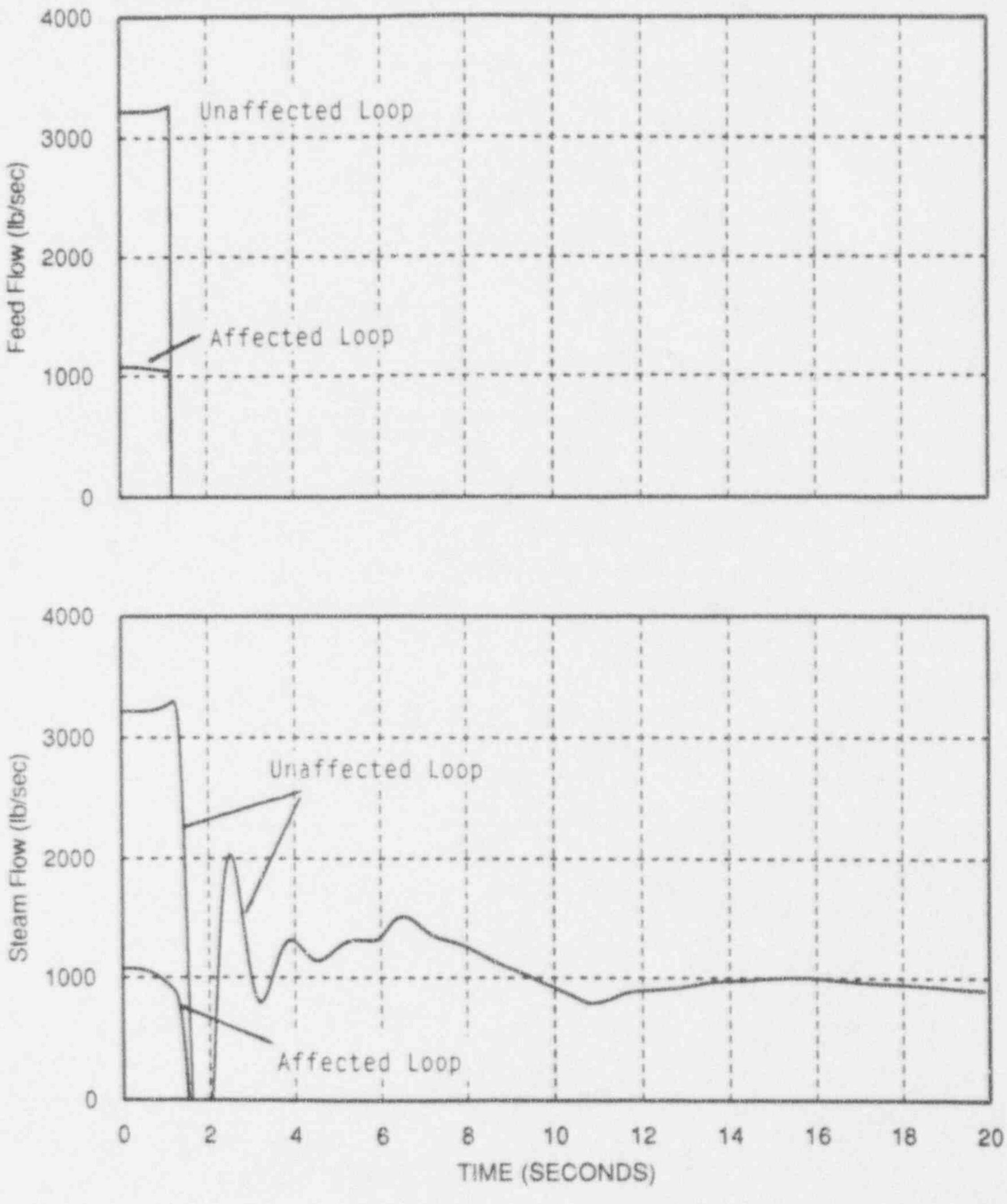
SEABROOK STATION	Locked Rotor With Offsite Power Available FIGURE 5.3- 5 , Sh. 1



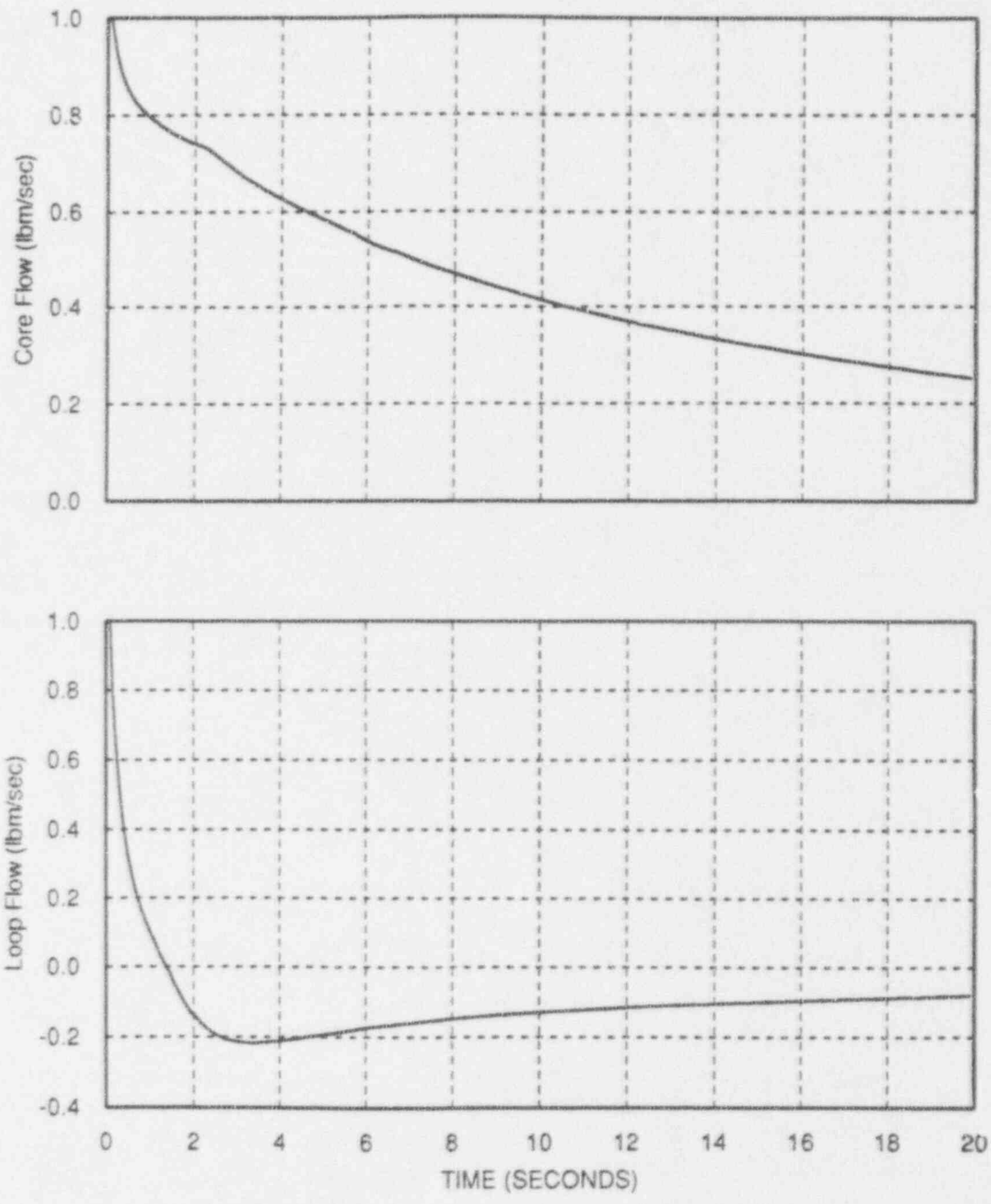
SEABROOK STATION	Locked Rotor With Offsite Power Available FIGURE 5.3-5 , Sh. 2



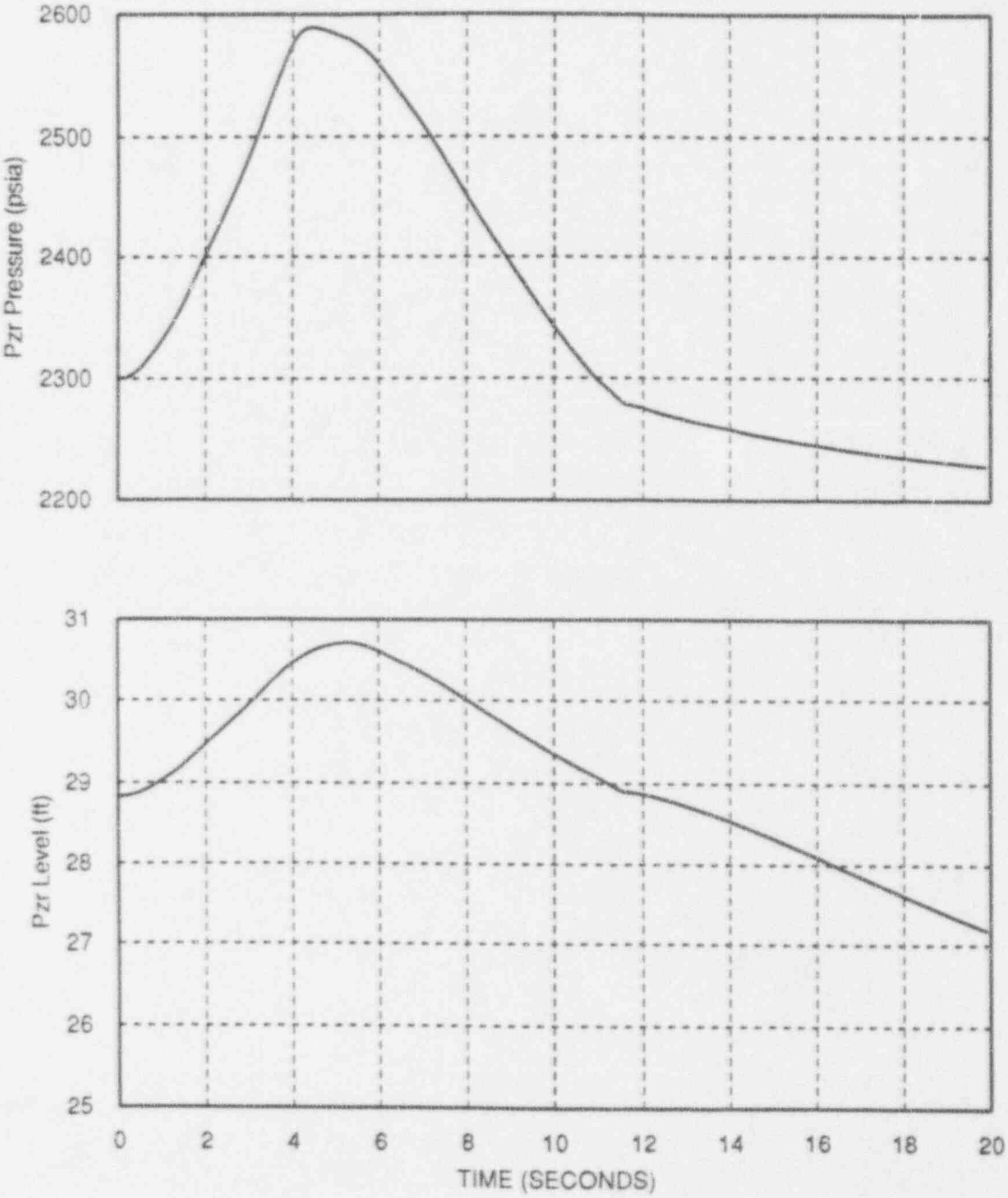
SEABROOK STATION	Locked Rotor With Offsite Power Available FIGURE 5.3- 5 , Sh. 3



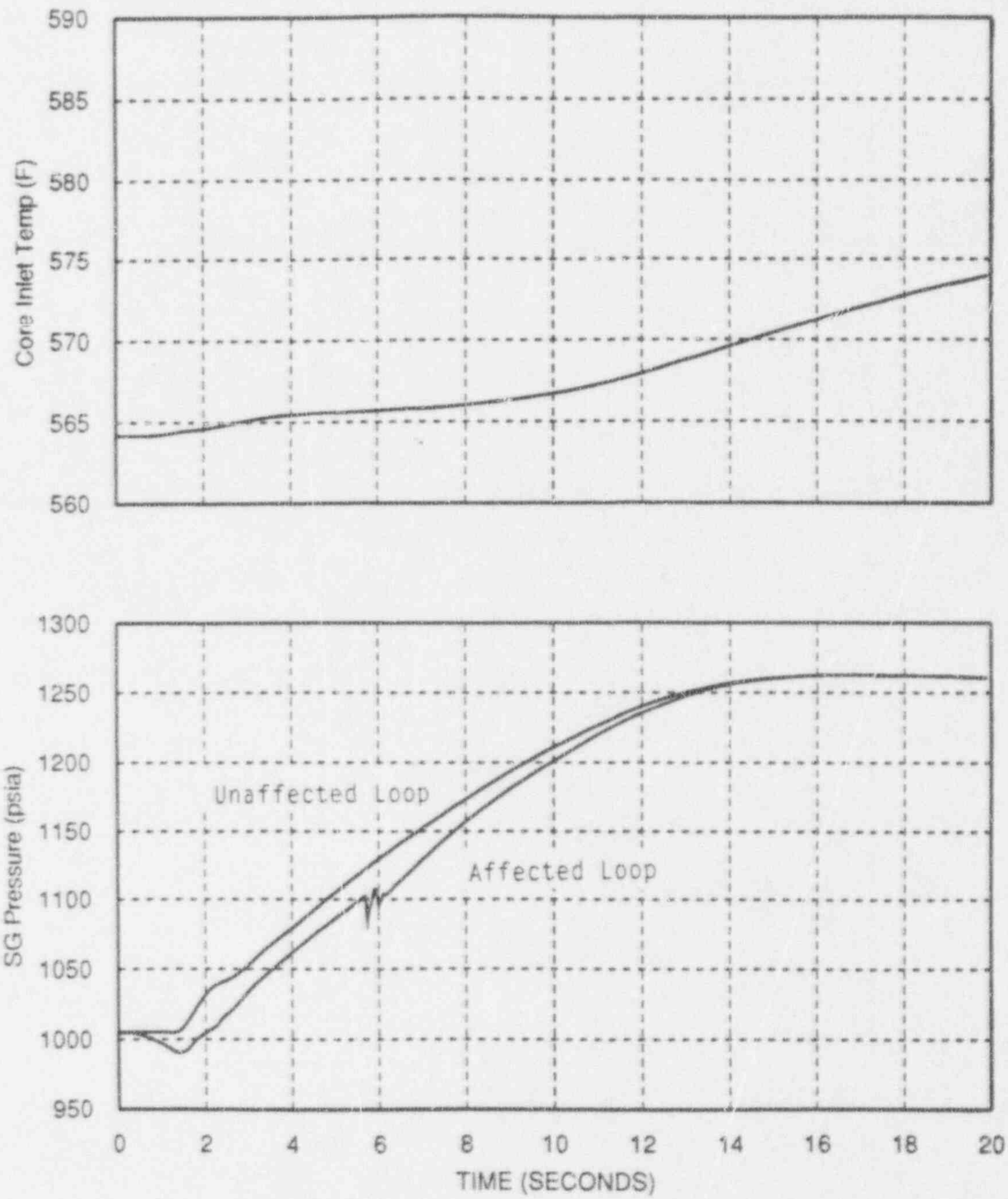
SEABROOK STATION	Locked Rotor With Offsite Power Available FIGURE 5.3-5 , Sh. 4



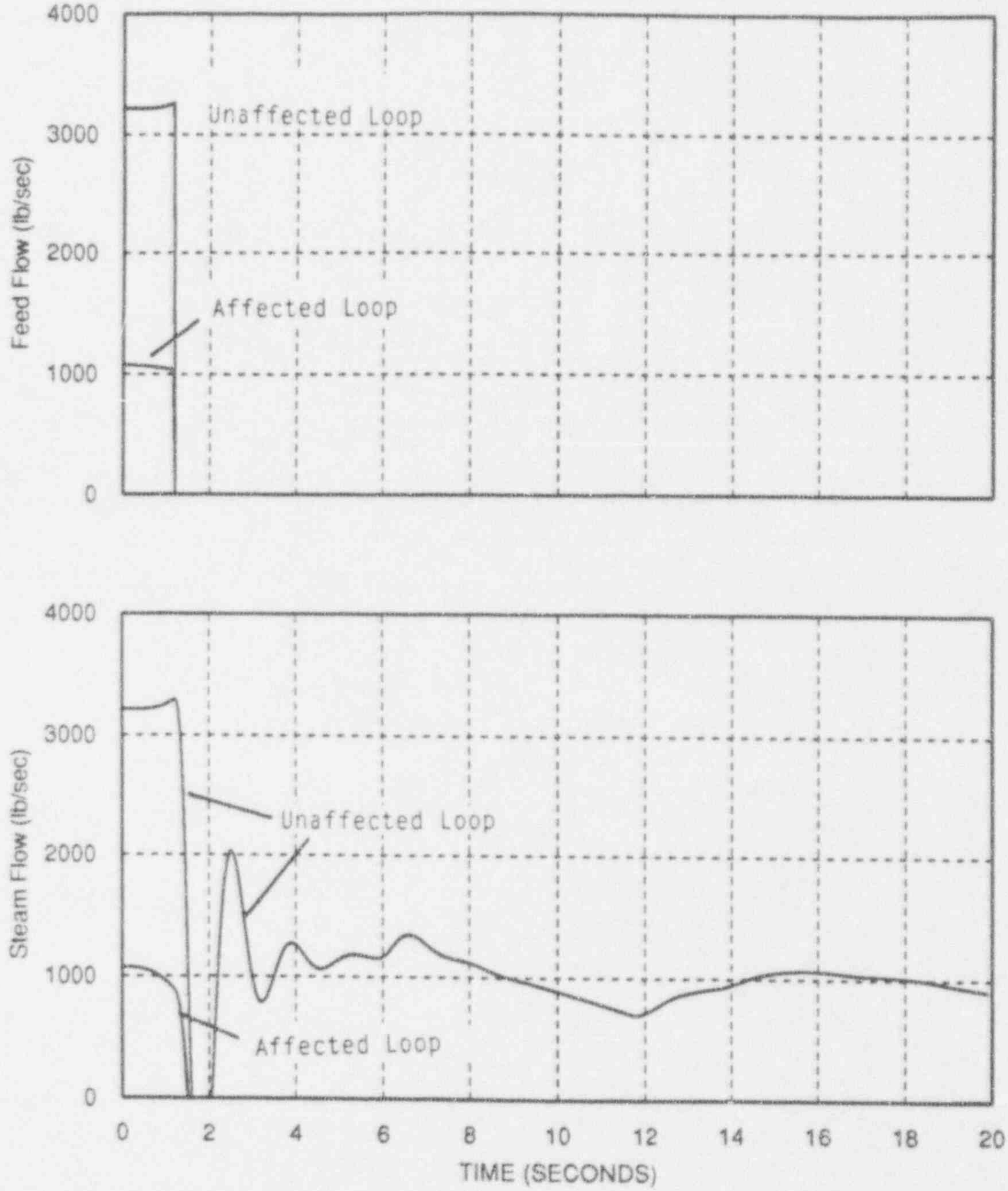
SEABROOK STATION	Locked Rotor With a Loss of Offsite Power FIGURE 5.3-6 , Sh. 1



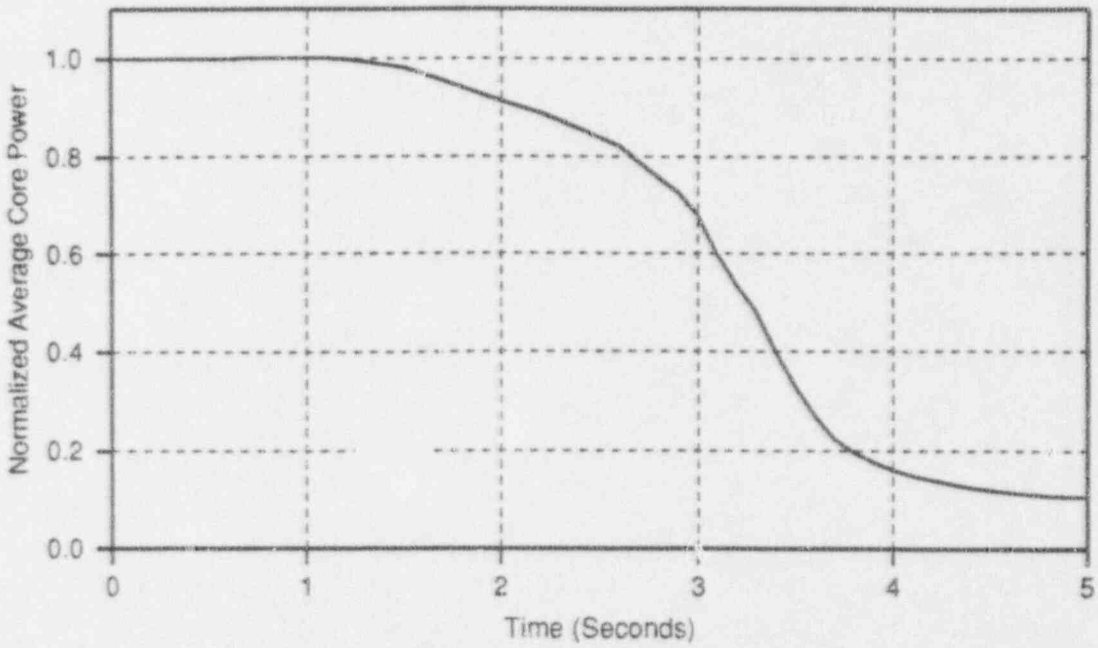
SEABROOK STATION	Locked Rotor With a Loss of Offsite Power FIGURE 5.3-6 , Sh. 2

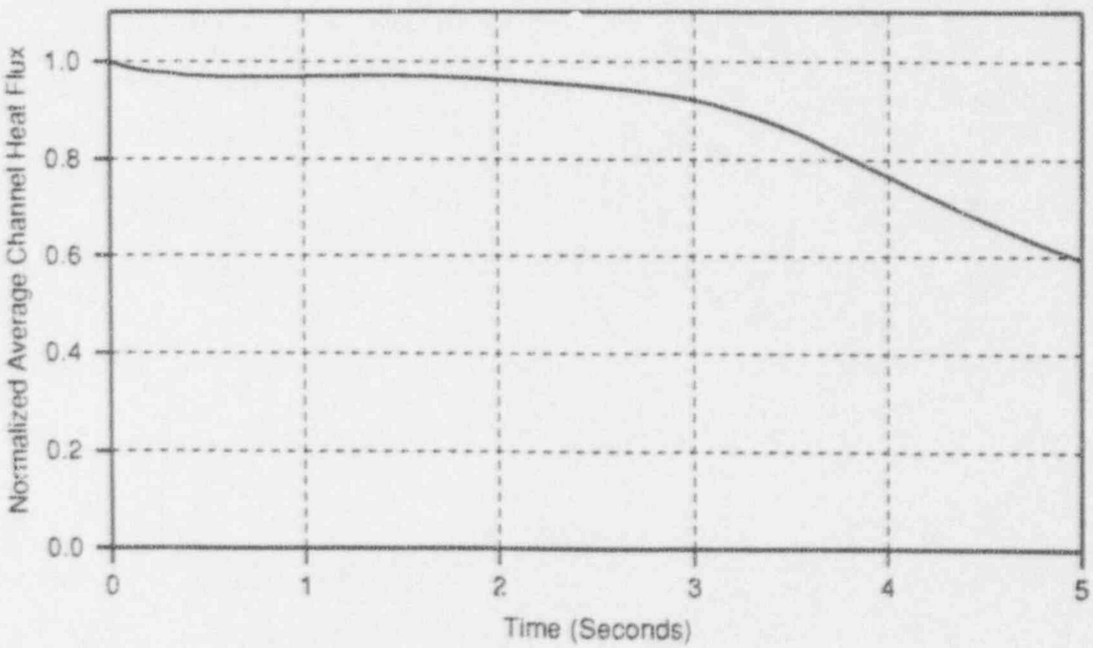


SEABROOK STATION	Locked Rotor With a Loss of Offsite Power FIGURE 5.3-6 , Sh. 3

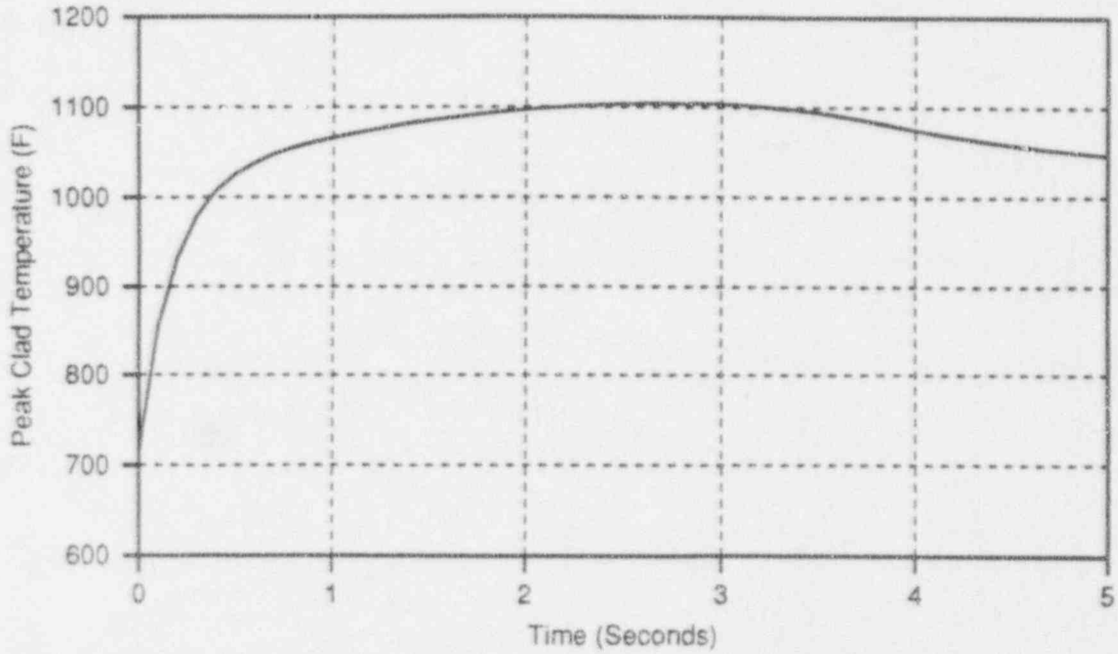


SEABROOK STATION	Locked Rotor With a Loss of Offsite Power FIGURE 5.3-6 , Sh. 4





SEABROOK STATION	Locked Rotor With a Loss of Offsite Power FIGURE 5.3-6 , Sh. 5



SEABROOK STATION	Locked Rotor With a Loss of Offsite Power FIGURE 5.3-6 , Sh. 6

5.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

A number of faults have been postulated which could result in reactivity and power distribution anomalies. Reactivity changes could be caused by control rod motion or ejection, boron concentration changes or addition of cold water to the Reactor Coolant System (RCS). Power distribution changes could be caused by control rod motion, misalignment, ejection, or by static means such as fuel assembly mislocation. Detailed analyses are presented for the most limiting of these events:

a. Uncontrolled Rod Cluster Control Assembly bank withdrawal from a subcritical or low power startup condition

b. Uncontrolled Rod Cluster Control Assembly bank withdrawal at power

c. Rod Cluster Control Assembly misalignment

d. Startup of an inactive reactor coolant pump at an incorrect temperature

e. Chemical and Volume Control System malfunction that results in a decrease in the boron concentration in the reactor coolant

f. Inadvertent loading and operation of a fuel assembly in an improper position

g. Spectrum of Rod Cluster Control Assembly ejection accidents.

Items a, b, d, and e above are considered to be ANS Condition II events, item f an ANS Condition III event, and item g an ANS Condition IV event. Item c entails both Condition II and III events. Events a, b, c, and g have been reanalyzed and results are presented in this section. Event d is precluded by technical specifications which prohibit 3-loop operation; event e is not affected by the changes discussed in Section 3; event f is precluded by being detectable without consequence during refueling/startup physics tests; these events have not been reanalyzed.

5.4.1 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition

5.4.1.1 Identification of Causes and Accident Description

A Rod Cluster Control Assembly (RCCA) withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCAs,

resulting in a power excursion. Such a transient could be caused by a malfunction of the Reactor Control or Rod Control Systems. This could occur with the reactor subcritical, at Hot Zero Power or at power. The "at power" case is discussed in Subsection 5.4.2.

Although the reactor is normally brought to power from a subcritical condition by means of RCCA withdrawal, initial startup procedures with a clean core call for boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (see Subsection 5.4.6, "Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant").

The RCCA drive mechanisms are wired into preselected bank configurations which are not altered during reactor life. These circuits prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power supplied to the banks is controlled such that no more than two banks can be withdrawn at the same time and in their proper withdrawal sequence. The RCCA drive mechanisms are of the magnetic latch type, and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the simultaneous withdrawal of the combination of two sequential control banks having the maximum combined worth at maximum speed.

This event is classified as an ANS Condition II incident (an incident of moderate frequency).

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise, terminated by the reactivity feedback effect of the negative Doppler coefficient. This self limitation of the power excursion is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the Reactor Protection System:

a. Source Range High Neutron Flux Reactor Trip - Actuated when either of two independent source range channels indicates a neutron flux level above a preselected manually adjusted setpoint. This trip function may be manually bypassed only after an 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.

b. Intermediate Range High Neutron Flux Reactor Trip - 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 only after two of the four power range channels are reading above approximately 10 percent of full power, and is automatically reinstated when three of the four power range channels indicate a power level below this value.

c. Power Range High Neutron Flux Reactor Trip (Low Setting) - Actuated when two out of the 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 the four power range channels indicate a power level above approximately 10 percent of full power, and is automatically reinstated only after three of the four channels indicate a power level below this value.

d. Power Range High Neutron Flux Reactor Trip (High Setting) - Actuated when two out of the four power range channels indicate a power level above a preset setpoint. This trip function is always active.

e. High Nuclear Flux Rate Reactor Trip - 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.

In addition, control rod stops on high intermediate range flux level (one of two) and high power range flux level (one out of four) serve to discontinue rod withdrawal and prevent the need to actuate the intermediate range flux level trip and the power range flux level trip, respectively.

5.4.1.2 Analysis of Effects and Consequences

a. Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages: first, an average core nuclear power transient calculation, then an average core heat transfer calculation, and finally, a DNBR calculation. The average core nuclear calculation is performed with SIMULATE[32], to determine the average power generation with time, including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. The average heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in CHIC-KIN[23]. The average heat flux is next used in VIPRE[4] for the transient DNBR calculation.

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 any given rate of reactivity insertion is strongly dependent on the Doppler coefficient, conservatively low values as a function of power are used.

2. Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the neutron flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. A highly conservative value is used in the analysis to yield the maximum peak heat flux.

3. The reactor is assumed to be at Hot Zero Power conditions. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect, thereby increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1.0 since this results in the worst nuclear power transient.

4. Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10 percent increase is assumed for the power range flux trip setpoint, raising it from the nominal value of 25 percent to 35 percent. Since the rise in the neutron flux is so rapid, the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.

5. The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two sequential control banks having the greatest combined worth at maximum speed (45 inches/minute).

6. The most limiting axial and radial power shapes, associated with having the two highest combined worth sequential control banks in their high worth position, is assumed in the DNB analysis.

7. The initial power level was assumed to be below the power level expected for any shutdown condition (10^{-9} of nominal power). The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

8. Two reactor coolant pumps are assumed to be in operation.

No single active failure in any systems or equipment will adversely affect the consequences of the accident.

b. Results

Figures 5.4-1 through 5.4-3 show the transient behavior for the uncontrolled RCCA bank withdrawal incident, with the accident terminated by reactor trip at 35 percent of nominal power. The reactivity insertion rate used is greater than that calculated for the two highest worth sequential control banks, both assumed to be in their highest incremental worth region. Figure 5.4-1 shows the neutron flux transient.

The energy release and the fuel temperature increases are relatively small. The thermal flux response, of interest for DNB considerations, is shown on Figure 5.4-2. There is a large margin to DNB during the transient since the rod surface heat flux remains below the design value, and there is a high degree of subcooling at all times in the core. Figure 5.4-3 shows the response of the average fuel and cladding temperature. The average fuel temperature increases to a value lower than the nominal full power value. The minimum DNBR at all times remains above the safety analysis limit value.

The calculated sequence of events for this accident is shown on Table 5.4-1. With the reactor tripped, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

5.4.1.3 Radiological Consequences

No radiological consequences have been calculated for this postulated accident since no fuel or clad damage is predicted.

5.4.1.4 Conclusions

In the event of a RCCA withdrawal accident from the subcritical condition, the core and the Reactor Coolant System are not adversely affected, since the combination of thermal

power and the coolant temperature result in a DNBR greater than the safety analysis limit value. Thus, no fuel or clad damage is predicted as a result of DNB.

5.4.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

5.4.2.1 Identification of Causes and Accident Description

Uncontrolled Rod Cluster Control Assembly (RCCA) bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise could eventually result in DNB. Therefore, in order to avert damage to the fuel clad, the Reactor Protection System is designed to terminate any such transient before the DNBR falls below the safety analysis limit value.

This event is classified as an ANS Condition II incident (an incident of moderate frequency).

The automatic features of the Reactor Protection System which prevent core damage following the postulated accident include:

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

b. Reactor trip is actuated if any two out of four ΔT channels exceed an Overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature and pressure to protect against DNB.

c. Reactor trip is actuated if any two out of four ΔT channels exceed an overpower ΔT setpoint.

d. A high pressurizer pressure reactor trip actuated from any two out of four pressure channels, which is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.

e. A high pressurizer water level reactor trip actuated from any two out of three level channels when the reactor power is above approximately 10 percent (Permissive P7).

In addition to the above listed reactor trips, there are the following RCCA withdrawal blocks:

a. High neutron flux (one out of four power range).

b. Overpower ΔT (two out of four).

c. Overtemperature ΔT (two out of four).

5.4.2.2 Analysis of Effects and Consequences

a. Method of Analysis

This transient is analyzed with the RETRAN Code[9]. This 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, pressure, and power level.

Plant characteristics and initial conditions are discussed in Subsection 5.0.3. In order to obtain conservative results for an uncontrolled rod withdrawal at power accident, the following assumptions are made:

1. Initial conditions of maximum core power and reactor coolant average temperature and minimum reactor coolant pressure, resulting in the minimum initial margin to DNB.

2. Reactivity coefficients - Two cases are analyzed:

   (a) Minimum reactivity feedback

   A least negative moderator coefficient of reactivity is assumed corresponding to the beginning of core life. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.

   (b) 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 assumed to be actuated at a conservative value of 118 percent of nominal full power.

   The ΔT trips include all adverse instrumentation and setpoint errors; the delays for trip actuation are assumed to be the maximum values.

4. The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

5. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combination of the two control banks having the maximum combined worth, at maximum speed.

The effect of RCCA movement on the axial core power distribution is accounted for by causing a decrease in the Overtemperature ΔT trip setpoint proportional to a decrease in margin to DNB.

No single active failure in systems or equipment will adversely offset the consequences of the accident.

b. Results

Figure 5.4-4 shows the transient response for a rapid RCCA withdrawal incident starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result, and margin to DNB is maintained.

The transient response for a slow RCCA withdrawal from full power is shown in Figures 5.4-5. Reactor trip on Overtemperature ΔT occurs after a longer period, and the rise in temperature and pressure is consequently larger than for rapid RCCA withdrawal. Again, the minimum DNBR is greater than the safety analysis limit value.

Figure 5.4-6 shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation, and for minimum and maximum reactivity feedback. It can be seen that two reactor trip functions provide protection over the entire range of reactivity insertion rates. These are the high neutron flux and Overtemperature ΔT functions. The minimum DNBR is never less than the safety analysis limit value.

Figures 5.4-7 and 5.4-8 show the minimum DNBR as a function of reactivity insertion rate for RCCA withdrawal incidents starting at 70 and 10 percent of full power respectively.

The results are similar to the 100 percent power case except that the initial power is decreased. In neither case does the DNBR fall below the safety analysis limit value.

The calculated sequence of events for this accident is shown on Table 5.4-1. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

5.4.2.3 Radiological Consequences

No radiological consequences have been calculated for this postulated accident since no fuel or clad damage is predicted.

5.4.2.4 Conclusions

The high neutron flux, Overpower ΔT, and Overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates, i.e., the minimum value of DNBR is always larger than the safety analysis limit value.

5.4.3 Rod Cluster Control Assembly Misoperation (System Malfunction or Operator Error)

5.4.3.1 Identification of Causes and Accident Description

Rod Cluster Control Assembly (RCCA) misalignment accidents include:

a. One or more dropped RCCAs within the same group.

b. A dropped RCCA bank.

c. Statically misaligned RCCA.

d. Withdrawal of a single RCCA.

Each RCCA has a position indicator channel which displays position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod at bottom signal, which actuates a local alarm and a control room annunciator. Group demand position is also indicated.

Full length RCCAs are always moved in preselected banks, and the banks are always moved in the same preselected sequence. Each bank of RCCAs is divided into two groups of four mechanisms each. The rods comprising a group operate in parallel through multiplexing

thyristors. The two groups in a bank move sequentially so that the first group is always within one step of the second group in the bank. A definite schedule of actuation or de-actuation of the stationary gripper, movable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Since the stationary gripper, movable gripper, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure which would cause rod withdrawal would affect a minimum of one group. Mechanical failures are in the direction of insertion, or immobility.

The dropped RCCA assemblies, dropped assembly bank, and statically misaligned assembly events are classified as ANS Condition II incidents (incidents of moderate frequency). The single RCCA withdrawal incident is classified as an ANS Condition III event.

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single RCCA from the inserted bank at full power operation. The operator could withdraw a single RCCA in the control bank since this feature is necessary to retrieve an assembly should one be accidentally dropped. The event analyzed must result from multiple wiring failures (probability for single random failure is on the order of 10^{-4}/year; refer to UFSAR Subsection 7.7.2.2) or multiple significant operator errors and subsequent and repeated operator disregard of event indication. The probability of such a combination of conditions is considered low such that the limiting consequences may include slight fuel damage.

Thus, consistent with the philosophy and format of ANSI N18.2, the event is classified as a Condition III event. By definition, "Condition III occurrences include incidents, any one of which may occur during the lifetime of a particular plant," and "shall not cause more than a small fraction of fuel elements in the reactor to be damaged..."

This selection of criterion is in accordance with General Design Criterion (GDC) 25 which states, "The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods." (Emphasis has been added.) It has been shown that single failures resulting in RCCA bank withdrawals do not violate specified fuel design limits. Moreover, no single malfunction can result in the withdrawal of a single RCCA. Thus, it is concluded that the criterion established for the single rod withdrawal at power is appropriate and in accordance with GDC 25.

A dropped RCCA or RCCA bank is detected by:

a. Sudden drop in the core power level as seen by the Nuclear Instrumentation System.

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

c. Rod at bottom signal.

d. Rod deviation alarm.

e. Rod position indication.

Misaligned RCCAs are detected by:

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

b. Rod deviation alarm.

c. Rod position indicators.

The rod deviation alarm alerts the operator to rod deviation with respect to the bank demand position of ±12 steps. Deviations of an RCCA from its group by ±12 steps have been considered. If the rod deviation alarm is not operable, the operator must take action as required by the Technical Specifications.

5.4.3.2 Analysis of Effects and Consequences

a. Dropped RCCAs, Dropped RCCA Bank, and Statically Misaligned RCCA

1. Method of Analysis

(a) One or More Dropped RCCAs from the Same Group

For evaluation of the dropped RCCA event, the transient system response is calculated using the RETRAN[7] code. 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.

Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the post drop primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the VIPRE[4] code. The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 7.

(b) Statically Misaligned RCCA

Steady-state power distribution is analyzed using the computer codes as described in Reference 7. The peaking factors are then used as input to the VIPRE code to calculate the DNBR.

2. Results

(a) One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion which may be detected by the power range negative neutron flux rate trip circuitry. If detected, the reactor is tripped within a few seconds following the drop of the RCCAs. The core is not adversely affected during this period, since power is decreasing rapidly. Following reactor trip, normal shutdown procedures are followed. The operator may manually retrieve the RCCA by following approved operating procedures.

For those dropped RCCAs which do not result in a reactor trip, power may be reestablished either by reactivity feedback or control bank withdrawal. Following a dropped rod event in manual rod control, the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a

concern, and establishing the automatic rod control mode of operation as the limiting case.

For a dropped RCCA 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. Figure 5.4-9 shows a typical transient response to a dropped RCCA (or RCCAs) in automatic control. In all cases, the minimum DNBR remains above the limit value.

(b) <u>Dropped RCCA Bank</u>

A dropped RCCA bank typically results in a reactivity insertion greater than 500 pcm which will be detected by the power range negative neutron flux rate trip circuitry. The reactor is tripped within a few seconds following the drop of an RCCA Bank. The core is not adversely affected during this period, since power is decreasing rapidly. Following reactor trip, normal shutdown procedures are followed to further cool down the plant. Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of ten minutes following the incident.

(c) <u>Statically Misaligned RCCA</u>

The most severe misalignment situations with respect to DNBR at significant power levels arise from cases in which one RCCA is fully inserted, or where bank D is inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the postulated conditions are approached. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the limit value.

This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values but with the increased radial peaking factor associated with the misaligned RCCA.

DNB calculations have been performed specifically for RCCAs missing from other banks at other power levels. These analyses show that the DNB and peak kW/ft situation is less severe than the bank D case discussed above.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the limit value. This case is analyzed assuming the initial reactor powers pressure and RCS temperatures are at their nominal values but with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation rate is well below that which would cause fuel melting.

Following the identification of an RCCA group misalignment condition by the operator, the operator must take action as required by the plant Technical Specifications and operating instructions.

b. <u>Single RCCA Withdrawal</u>

1. <u>Method of Analysis</u>

Power distributions within the core are calculated using the computer codes as described in Reference 7. The peaking factors are then used by VIPRE to calculate the DNBR for the event. Several rod withdrawal transients at various power levels were analyzed. Control banks were initially inserted to the power dependent insertion limits. This incident is assumed to occur at beginning-of-life since this results in the most positive value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

2. Results

For the single rod withdrawal event, two scenarios have been considered as follows:

(a) If the reactor is in the manual control mode, continuous withdrawal of a single RCCA 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 RCCA. In terms of the overall system response, this case is similar to those presented in Subsection 5.4.2; however, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBRs than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNB 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 DNBR less than the limit value is 5 percent.

(b) If the reactor is in the automatic control mode, the multiple failures that result in the withdrawal of a single RCCA will result in the immobility of the other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case (a) described above.

For such cases as above, a reactor trip will ultimately ensue, although not sufficiently fast in all instances to prevent a minimum DNBR in the core of less than the limit value. Following reactor trip, normal shutdown procedures are followed.

5.4.3.3 Radiological Consequences

No radiological consequences have been calculated for these postulated accidents since no significant fuel or clad damage is predicted. The case of the accidental withdrawal of a single RCCA has an upper limit potential of some clad damage; however, the radiological releases and offsite doses are bounded by the results of Subsection 5.4.7 (radiological consequences for the spectrum of rod ejection accidents).

5.4.3.4 Conclusions

For cases of dropped RCCAs or dropped banks, for which the reactor is tripped by the power range negative neutron flux rate trip, there is no reduction in the margin to core thermal limits, and consequently the DNB design basis is met. It is shown for all cases which do not result in reactor trip that the DNBR remains greater than the limit value and, therefore, the DNB design is met.

For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (static misalignment), the DNBR remains greater than the limit value.

For the case of the accidental withdrawal of a single RCCA, with the reactor in the automatic or manual control mode and initially with control banks at the power dependent insertion limit, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total fuel rods in the core.

5.4.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature

Three loop operation at Seabrook Station is prohibited by technical specifications. Therefore this event was not reanalyzed.

5.4.5 Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant

The previous UFSAR analysis of these events is not impacted by the changes to input parameters and assumptions discussed in Section 3 of this report. Therefore these events have not been reanalyzed.

The maximum reactivity insertion rate for boron dilution at power is bounded by the rates analyzed in Section 5.4.2 (RCCA bank withdrawal). The OTΔT and OPΔT trips assure that neither DNB nor centerline melting occur[7].

5.4.6 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position

5.4.6.1 Identification of Causes and Accident Description

Fuel and core loading errors, such as can arise from the inadvertent loading of one or more fuel assemblies into improper positions, loading 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, will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment.

Any 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 4 percent uncertainty margin included in the design value of power peaking factor assumed in the analysis of Condition I and Condition II transients. Successful completion of the reload startup physics tests performed in accordance with ANSI/ANS-19.6.1 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. Prior to core load the assemblies located in the spent fuel pool are mapped. 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 end up with the desired core configuration. Lastly, once the core is loaded, the assemblies and components in the reactor vessel are mapped to verify compliance with the core loading pattern.

The power distortion due to any combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with fixed incore detectors. In addition to the fixed incore detectors, thermocouples are located at the top of about one third of the fuel assemblies in the core. There is a high probability that these thermocouples would also indicate any abnormally high coolant enthalpy rise. Incore flux measurements are taken during the startup subsequent to every refueling operation.

This event is classified as an ANSI Condition III incident (an infrequent incident).

5.4.6.2 Radiological Consequences

No radiological consequences for this postulated accident have been calculated since no significant fuel or clad damage is predicted. Any localized fuel or clad damage that may result from enrichment errors is assumed to result in radiological consequences which are less severe than those presented in Subsection 5.4.7 (radiological consequences for the spectrum of rod ejection accidents).

5.4.6.3 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 DNBR 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 physics test program or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

5.4.7 Spectrum of Rod Cluster Control Assembly Ejection Accidents

5.4.7.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Certain features in the Seabrook pressurized water reactor 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, together with a thorough quality control (testing) program during assembly, and a nuclear design which lessens the potential ejection worth of RCCAs, and minimizes the number of assemblies inserted at high power levels.

Even if a rupture of a RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCAs inserted only far enough to permit load follow. Therefore, should an RCCA be ejected from its normal position during full power operation, only a minor reactivity excursion, at worst, could be expected to occur.

Reactor protection for this accident is provided by the high neutron flux trip (high and low setting).

This event is classified as an ANS Condition IV incident. Due to the extremely low probability of a RCCA ejection accident, some fuel damage could be considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy, have been carried out as part of the SPERT project by the Idaho Nuclear Corporation[34]. Extensive tests of UO_2 zirconium clad fuel rods representative of those in pressurized water reactor-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT[35] results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by about 10 percent with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure, (large fuel dispersal, large pressure rise) even for irradiated rods, did not occur below 300 cal/gm.

In view of the above experimental results, criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

1. Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel.

2. Average clad temperature at the hot spot below the temperature at which clad embrittlement may be expected (2700°F).

3. Peak reactor coolant pressure less than that which could cause stresses to exceed the faulted condition stress limits.

4. Fuel melting will be limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion 1 above.

5.4.7.2 Analysis of Effects and Consequences

a. Method of Analysis

The RCCA ejection transient is evaluated using the methodology described in Reference[26]. This method makes use of a power comparison between the CHIC-KIN[23] and STAR[26] codes to determine conservative Doppler reactivity weighting factors that account for the effect of local Doppler feedback near the ejected RCCA location on the average core power response. In addition, the reduction in the post-ejection radial peaking factor is

conservatively determined by comparing the peak nodal powers predicted by the STAR code, which includes Doppler feedback, to the peak nodal powers predicted by the SIMULATE[32] code with no Doppler feedback.

The CHIC-KIN code is used to evaluate both the average core power response and the thermal response (fuel and clad temperatures and enthalpies) at the core hot spot following the RCCA ejection. The average core power response is determined using the conservative Doppler reactivity weighting factors discussed above. The CHIC-KIN hot channel evaluation makes use of the conservative Doppler flattening of the post-ejection radial peak discussed above.

The DNBR analysis is performed with the VIPRE code[4]. This analysis uses the average core power response predicted with CHIC-KIN, in conjunction with the post-ejection radial peaking factor, the Doppler flattening of the radial peak, and conservative axial flux profiles.

The RCCA ejection analysis considers cases at both beginning and end of core life, with the core initially at both full and zero power. The following assumptions are used in the analysis:

1. The highest worth RCCA, initially inserted to the rod insertion limit, is assumed to eject in 0.1 seconds.

2. Conservative reactor kinetics parameters are used, including the appropriate uncertainties.

3. The assumed scram reactivity insertion vs. time is based on the predicted total scram rod worth, with allowances for the highest worth ejected and stuck rods and the appropriate uncertainty on the total scram rod worth. The normalized reactivity vs. rod position assumed in the analysis considered a slightly bottom skewed axial flux profile as discussed in Section 5.0.3.

4. The least negative moderator temperature coefficient, including uncertainty, is used for the case specific time in core life. The least negative Doppler defect, including uncertainty, is used for the case specific time in core life. Credit is taken for the effect of local Doppler feedback (near the ejected RCCA) in reducing the increase in core power.

5. Credit is taken for the reduction in the post-ejected radial peak due to local Doppler feedback. Reduction of the post-ejected axial peak due to local Doppler feedback is not credited.

6. The hot channel analysis uses a conservatively low DNB heat flux.

7. The fuel to clad gap heat transfer coefficients are chosen to maximize the core heat flux in the average channel CHIC-KIN analysis, and to maximize the fuel and clad temperatures in the hot channel CHIC-KIN analysis.

Reactor protection for a rod ejection is provided by the high neutron flux trip (high and low setpoints). These protection functions are part of the Reactor Trip System. No single failure of the Reactor Trip System will negate the protection function required for the rod ejection accident, or adversely affect the consequences of the accident.

The pressure surge in the RCS due to an ejected rod is bounded by previous calculations (documented in the UFSAR) and will not be repeated below. Previous calculations were based on a conservatively high ejected rod worth of $1.00 reactivity at HFP, BOL conditions. The currently predicted ejected rod worths, including uncertainty, are significantly below $1.00 of reactivity. Therefore, the peak pressure resulting from a rod ejection is bounded by the previous UFSAR analysis, which will not be repeated here.

b. Results

A summary of the four cases evaluated is given in Table 5.4-2. The nuclear power and hot spot fuel and clad temperature transient for the worst cases (beginning-of-life, full power and end-of-life, full power) are presented in Figures 5.4-10 through 5.4-11. In all cases, the radially averaged fuel enthalpy and peak clad temperature remain below the limits. In addition, fuel melting was not predicted for any case.

The calculated sequence of events for the worst case rod ejection accidents, as shown in Figures 5.4-10 through 5.4-11, is presented in Table 5.4-1. For all cases, reactor trip occurs very early in the transient, after which the nuclear power excursion is terminated. The reactor will remain subcritical following reactor trip.

The ejection of an RCCA constitutes a break in the Reactor Coolant System, located in the reactor pressure vessel head. The effects and consequences of loss-of-coolant accidents are discussed in Section 5.6.4. Following the RCCA ejection, the operator would follow the same emergency instructions as for any other loss-of-coolant accident to recover from the event.

It is assumed that fission products are released from the gaps of all rods entering DNB. In all cases considered, less than 10 percent of the rods entered DNB based on an analysis using VIPRE[4].

5.4.7.3 Radiological Consequences

Input parameters and assumptions for the radiological consequence analysis previously performed in the UFSAR have not changed. Therefore, that analysis is not repeated here.

5.4.7.4 Conclusions

The analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the Reactor Coolant System. The analyses have demonstrated that the upper limit in fission product release as a result of a number of fuel rods entering DNB amount to the release from 10 percent of the fuel rods in the core. The doses which have been calculated for the Control Rod Ejection Accident are below the values specified in 10 CFR Part 100, "Reactor Site Criteria."

TABLE 5.4-1
(Sheet 1 of 3)

TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
a. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition.	Initiation of uncontrolled rod withdrawal from 10^{-9} of nominal power	0.0
	Power range high neutron flux low setpoint reached	10.4
	Peak nuclear power occurs	10.5
	Rods begin to fall into core	10.9
	Minimum DNBR occurs	11.0
	Peak average clad temperature occurs	11.0
	Peak heat flux occurs	11.0
	Peak centerline fuel temperature occurs	12.2
b. Uncontrolled RCCA Bank Withdrawal at Power		
1. 30 pcm/sec reactivity insertion rate	Initiation of uncontrolled RCCA withdrawal	0
	Power range high neutron flux high trip setpoint reached	4.75
	Rods begin to fall into core	5.25
	Minimum DNBR occurs	6.40

TABLE 5.4-1
(Sheet 2 of 3)

TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
2. 3 pcm/sec reactivity insertion rate	Initiation of uncontrolled RCCA withdrawal	0
	Overtemperature ΔT reactor trip signal initiated	48.2
	Rods begin to fall into core	50.2
	Minimum DNBR occurs	50.6
c. Startup of an Inactive Reactor Coolant Loop	Initiation of pump startup	0.0
	Power reaches P-8 trip setpoint	10.2
	Rods begin to drop	12.2
	Minimum DNBR occurs	12.6
d. Rod Cluster Control Assembly Ejection		
1. Beginning-of-Life, Full Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.10
	Peak nuclear power occurs	0.12
	Rods begin to fall into core	0.60
	Peak heat flux occurs	1.12
	Peak clad temperature occurs	1.54
	Peak fuel average temperature	1.88
2. End-of-Life, Full Power	Initiation of rod ejection	0
	Power range high neutron flux low setpoint reached	0.08
	Peak nuclear power occurs	0.12

TABLE 5.4-1
(Sheet 3 of 3)

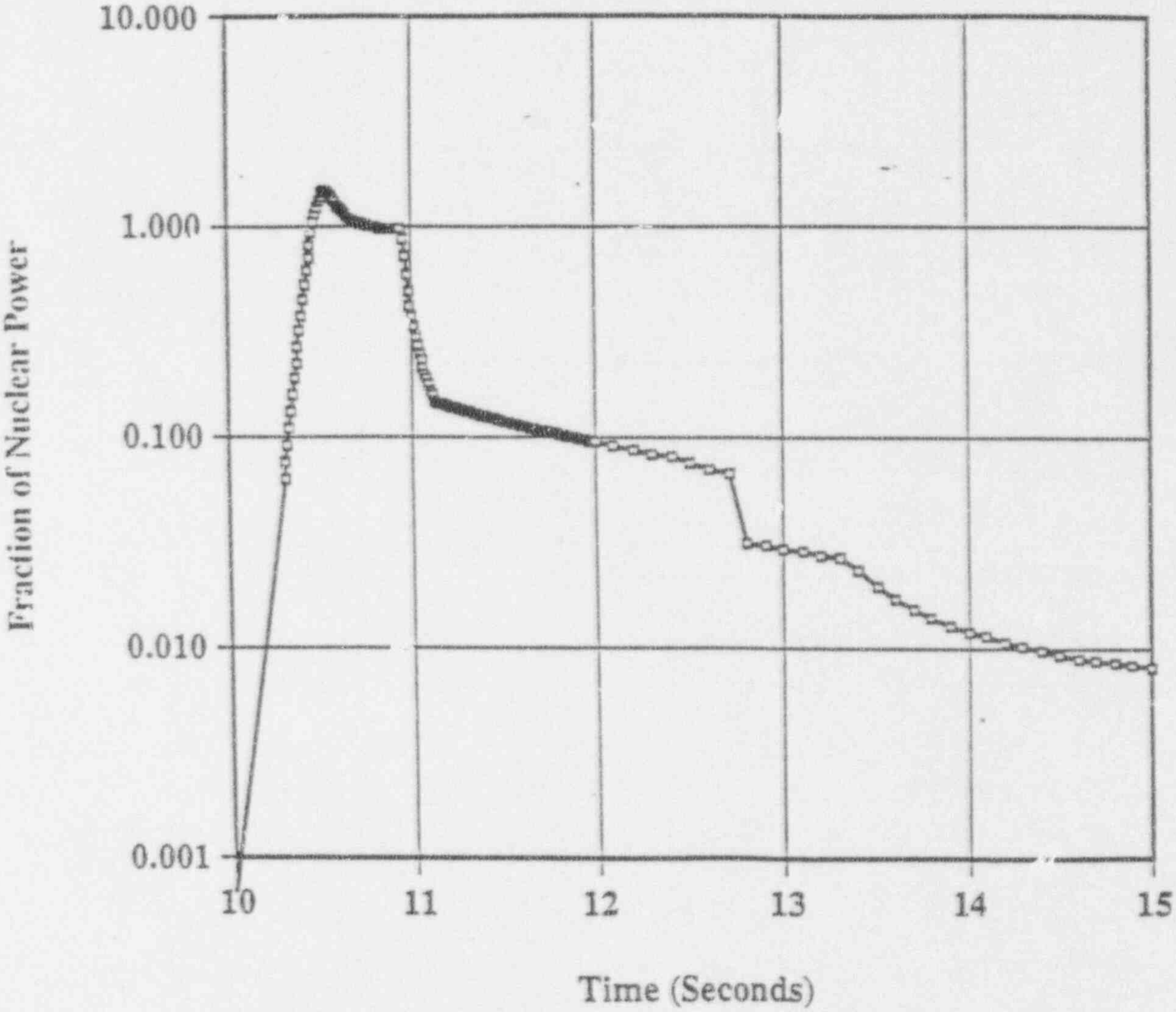
TIME SEQUENCE OF EVENTS FOR INCIDENTS
THAT CAUSE REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
	Rods begin to fall into core	0.58
	Peak heat flux occurs	1.58
	Peak fuel average temperature occurs	2.50
	Peak clad temperature occurs	2.44

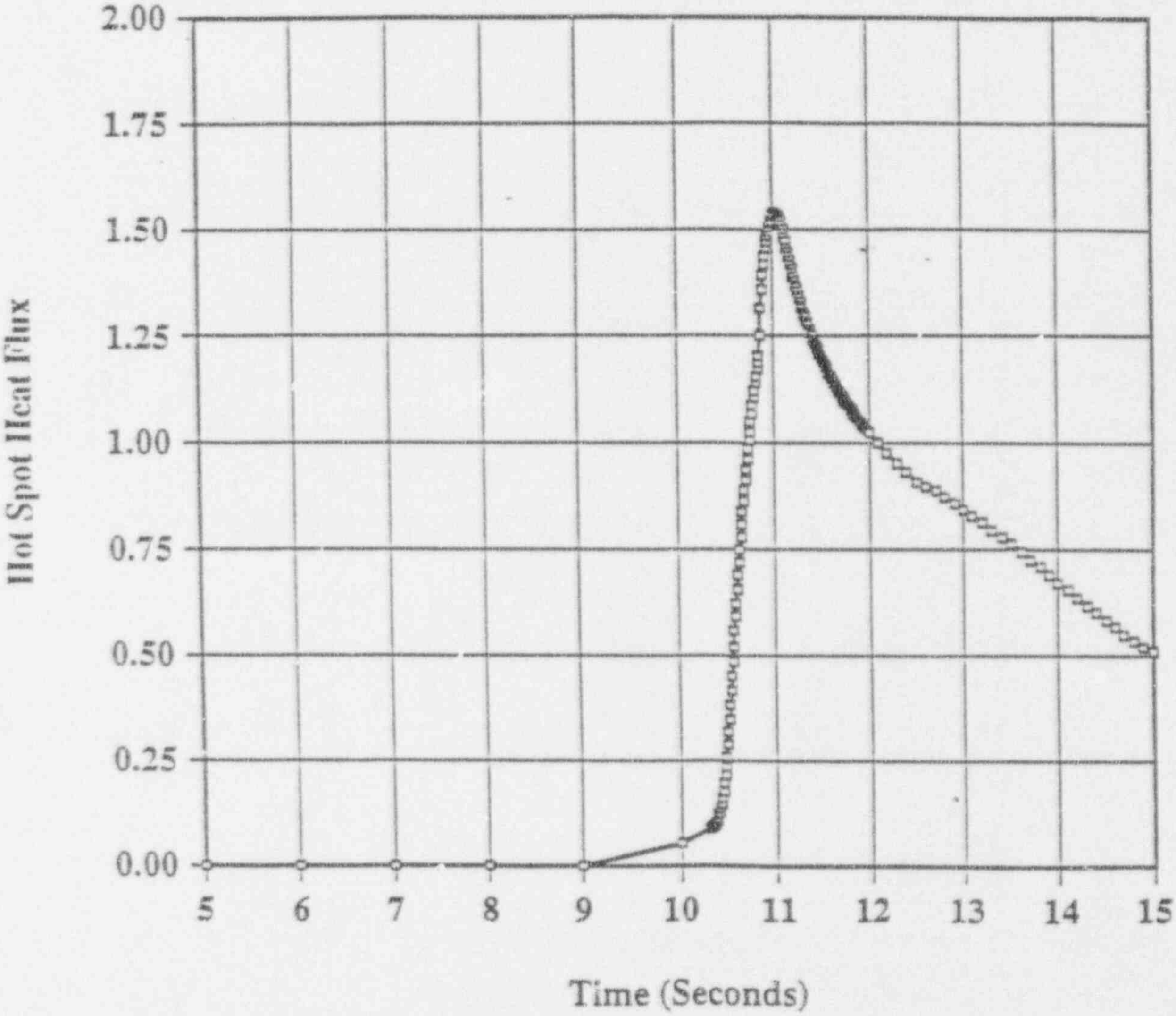
TABLE 5.4-2

PARAMETERS USED IN THE ANALYSIS OF THE
ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

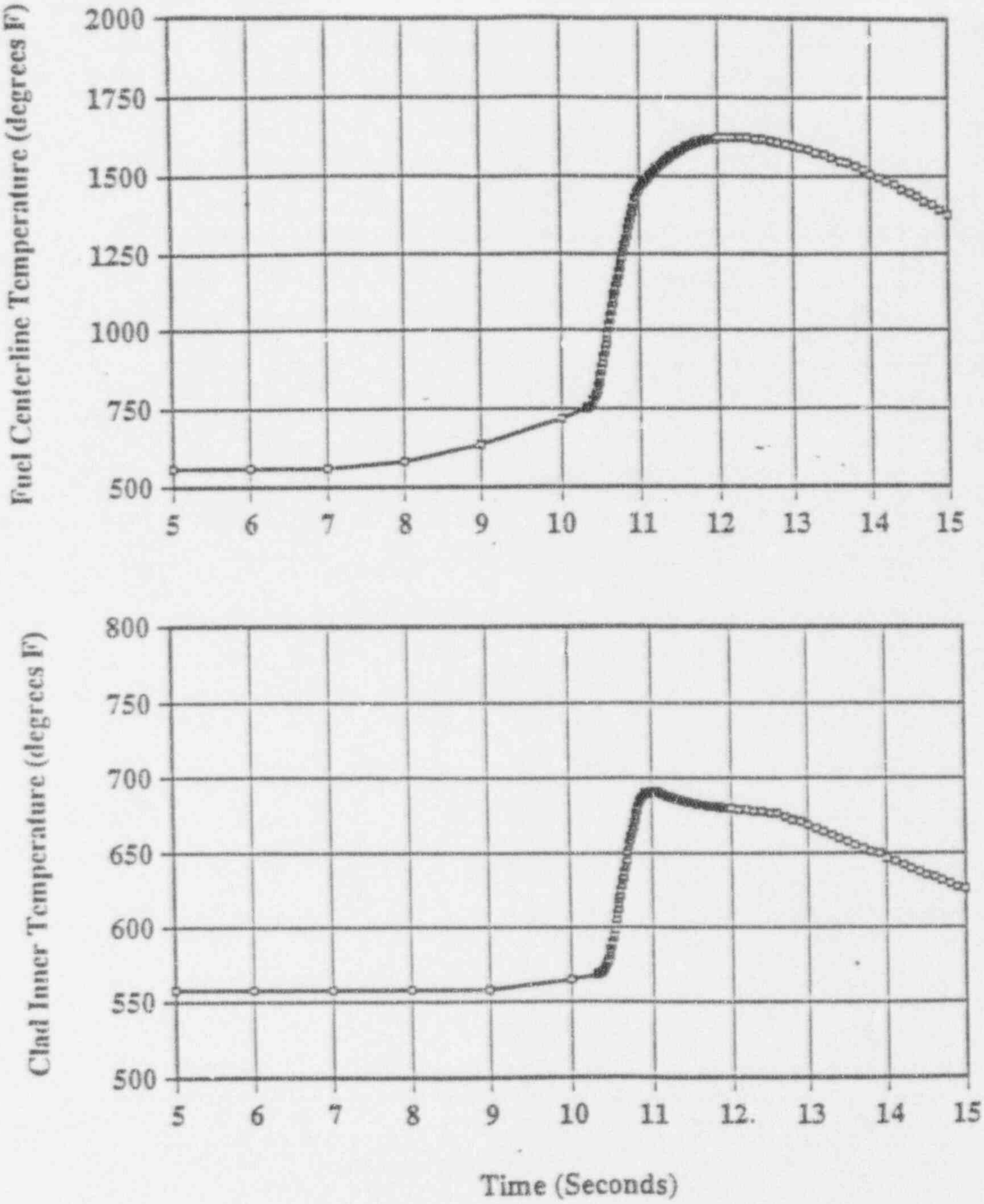
TIME IN LIFE	BOL-HFP	BOL-HZP	EOL-HFP	EOL-HZP
Power Level, %	102	0	102	0
Ejected rod worth, % ΔK	0.099	0.42	0.11	0.54
Delayed neutron fraction, %	0.55	0.55	0.46	0.46
Feedback reactivity weighing	1.00	1.32	1.00	1.59
Trip reactivity, % Δk	5.47	4.0	4.0	4.0
F_q before rod ejection	2.50	--	2.50	--
F_q after rod ejection	2.77	9.72	2.83	13.78
Max. fuel center temperature, °F	4486	4638	4401	1603
Max. clad temperature, °F	1108	825	1168	635
Max. fuel store energy, cal/gm	134.6	139.8	129.8	45.7
% Fuel Melt	0	0	0	0



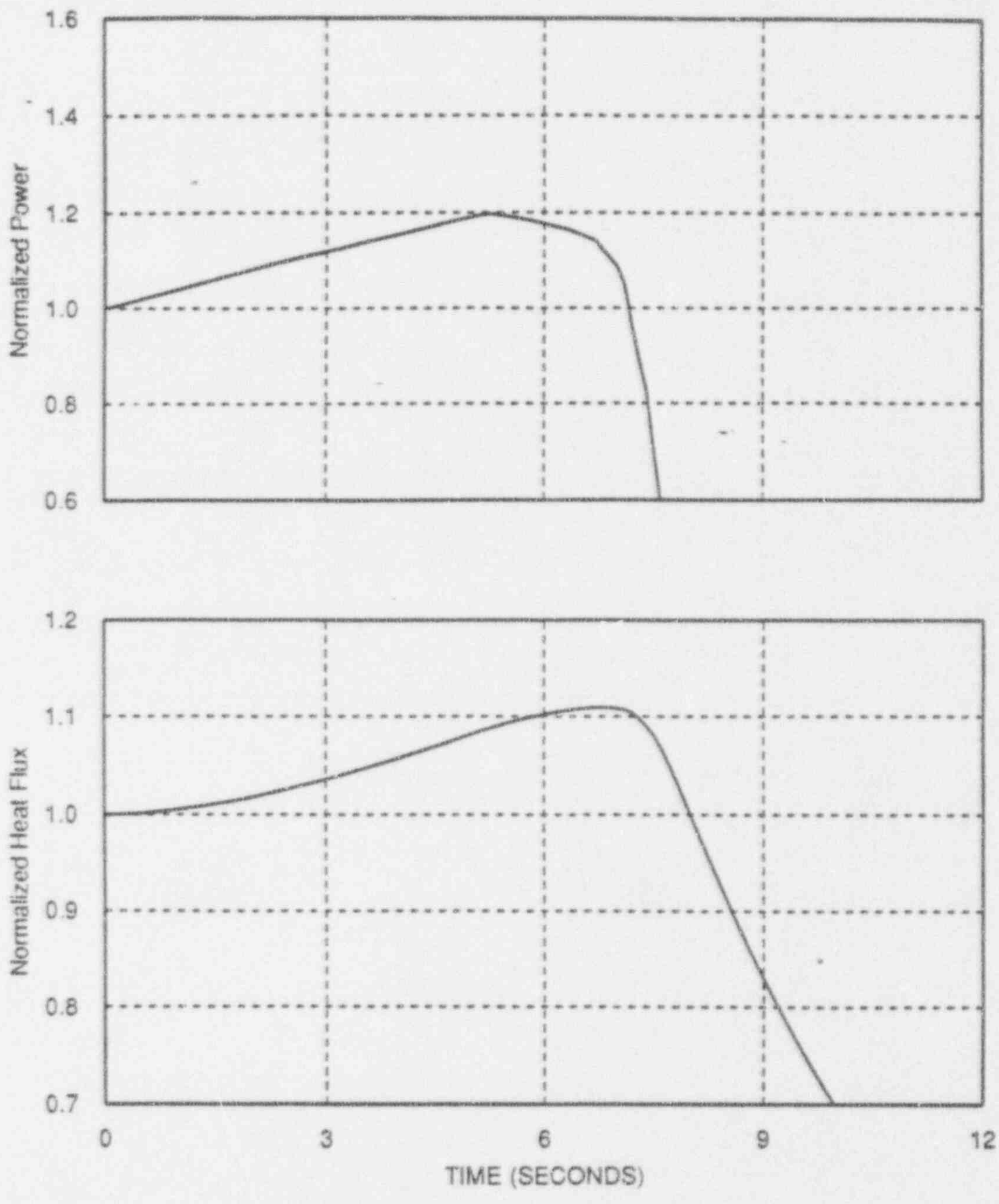
SEABROOK STATION	Neutron Flux Transient for Uncontrolled Rod Withdrawal from a Subcritical Condition
	FIGURE 5.4-1



SEABROOK STATION	Thermal Flux Transient for Uncontrolled Rod Withdrawal from a Subcritical Condition
-	FIGURE 5.4-2



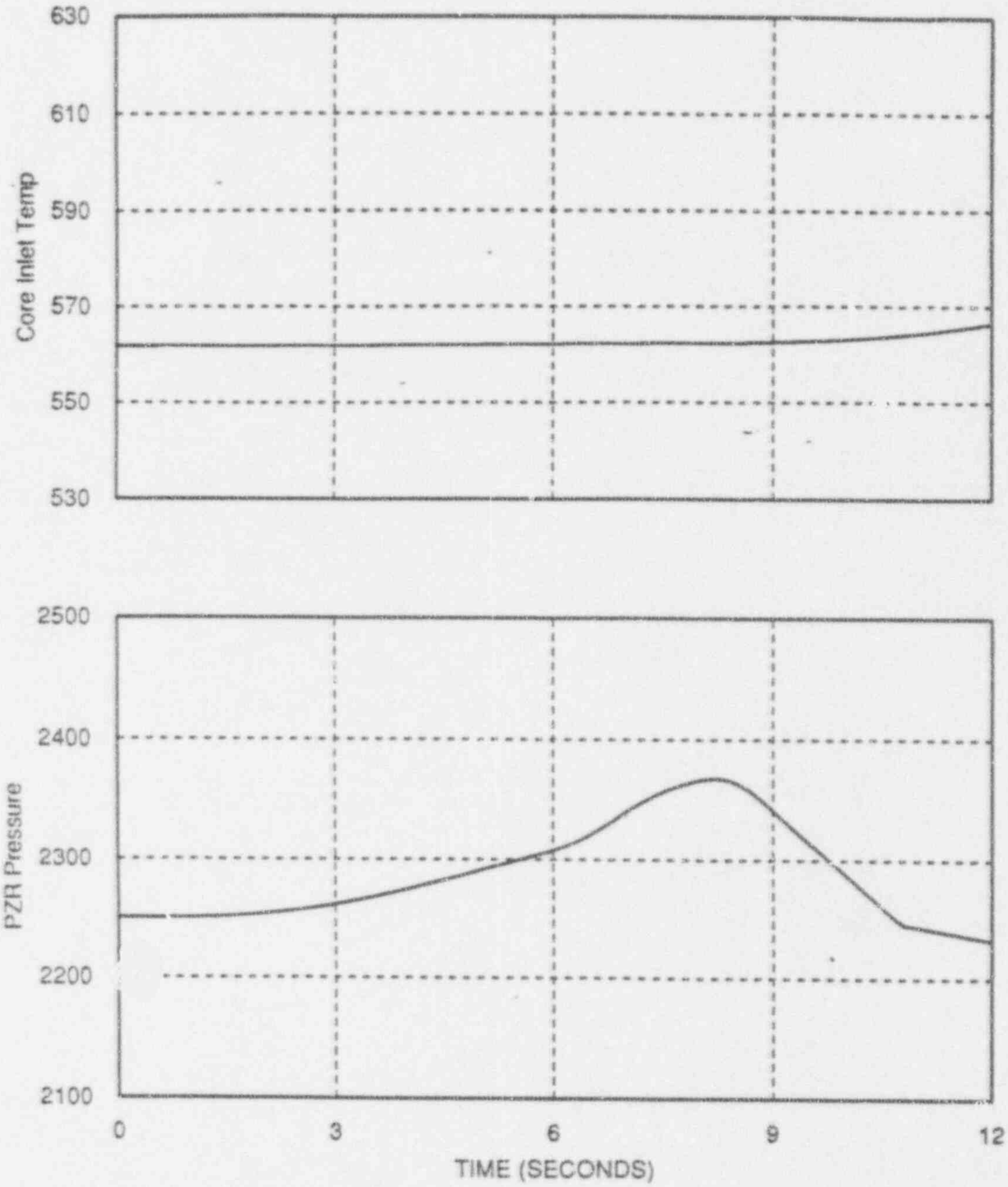
SEABROOK STATION	Fuel and Clad Temperature Transients for Uncontrolled Rod Withdrawal from a Subcritical Condition	
		FIGURE 5.4-3



Seabrook Station

Uncontrolied RCCA Bank Withdrawa! from
Full Power with Minimum Reactivity
Feedback (30 pcm/sec Insertion Rate)

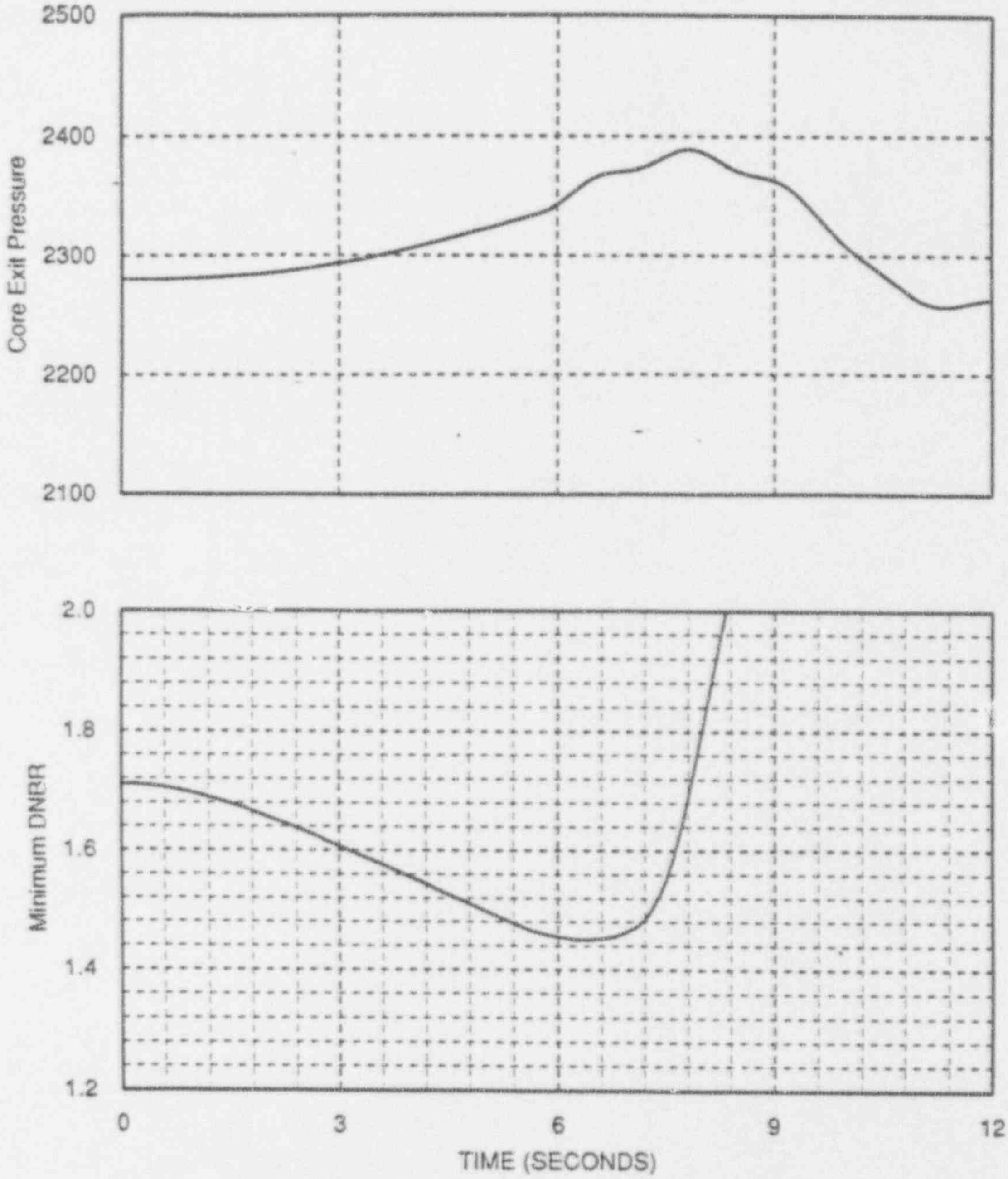
FIGURE 5.4-4 , Sh. 1



Seabrook Station

Uncontrolled RCCA Bank Withdrawal from Full Power with Minimum Reactivity Feedback (30 pcm/sec Insertion Rate)

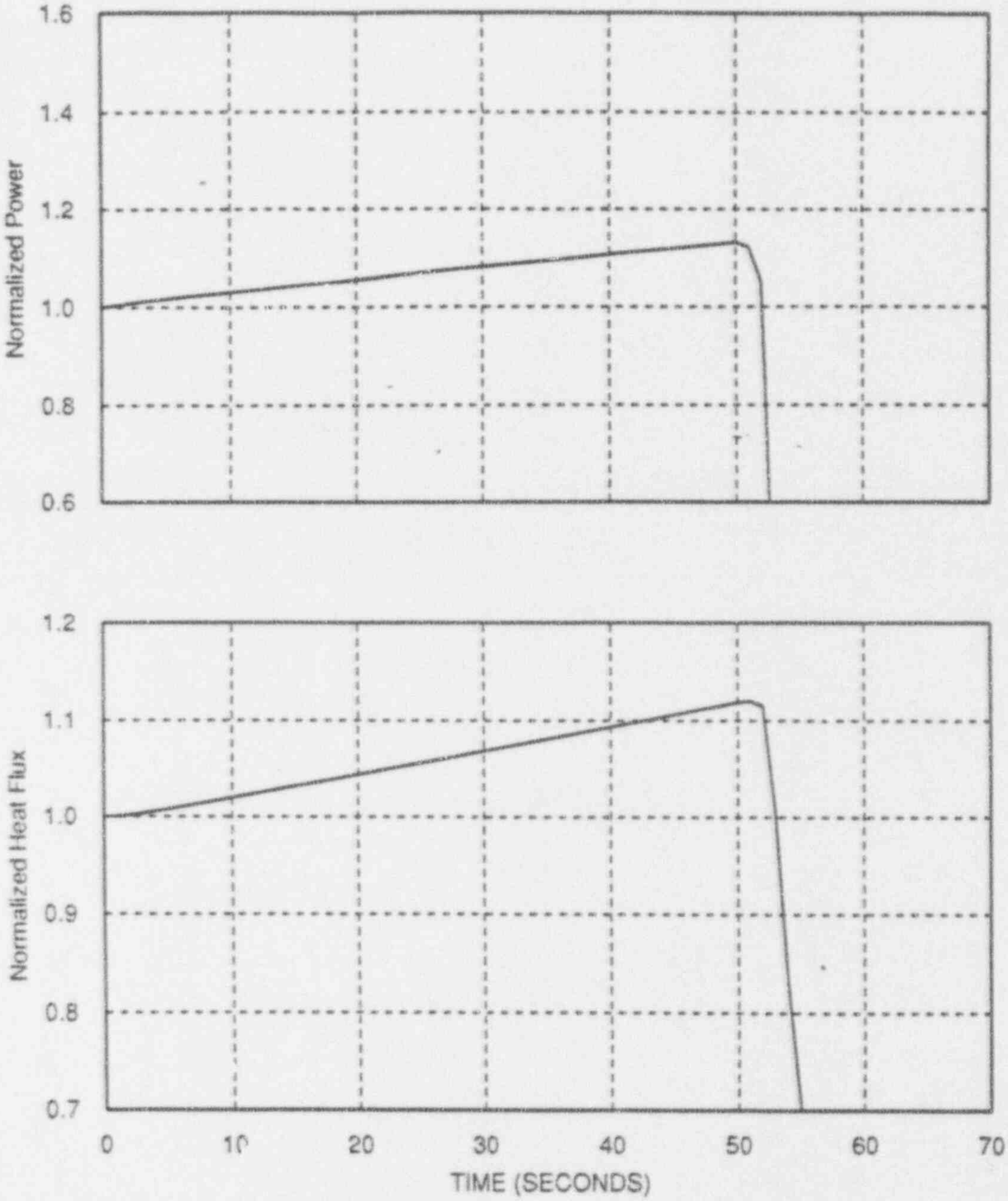
FIGURE 5.4-4 , Sh. 2



Seabrook Station

Uncontrolled RCCA Bank Withdrawal from Full Power with Minimum Reactivity Feedback (30 pcm/sec Insertion Rate)

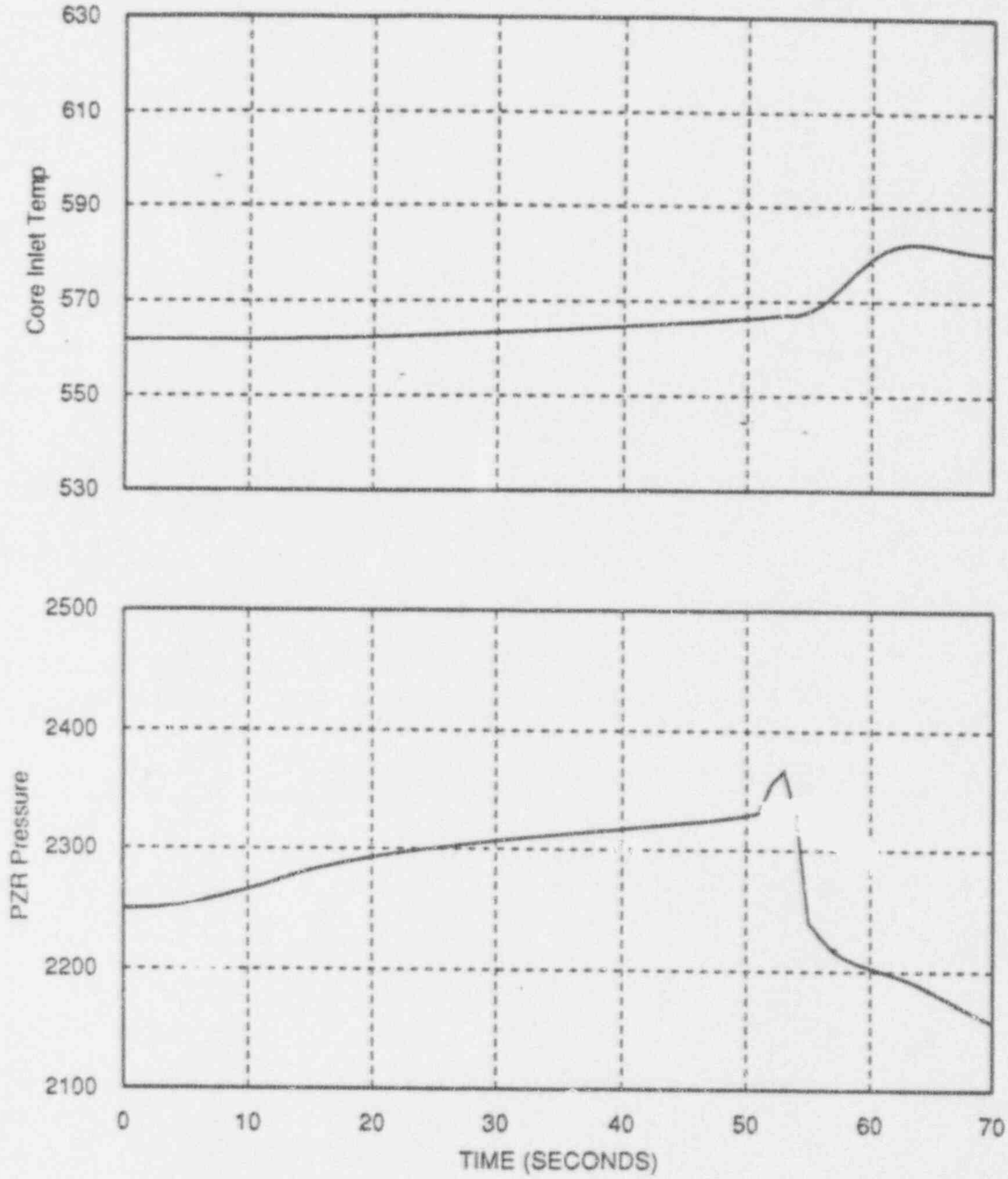
FIGURE 5.4-4 , Sh. 3



Seabrook Station

Uncontrolled RCCA Bank Withdrawal from Full Power with Minimum Reactivity Feedback (03 pcm/sec Insertion Rate)

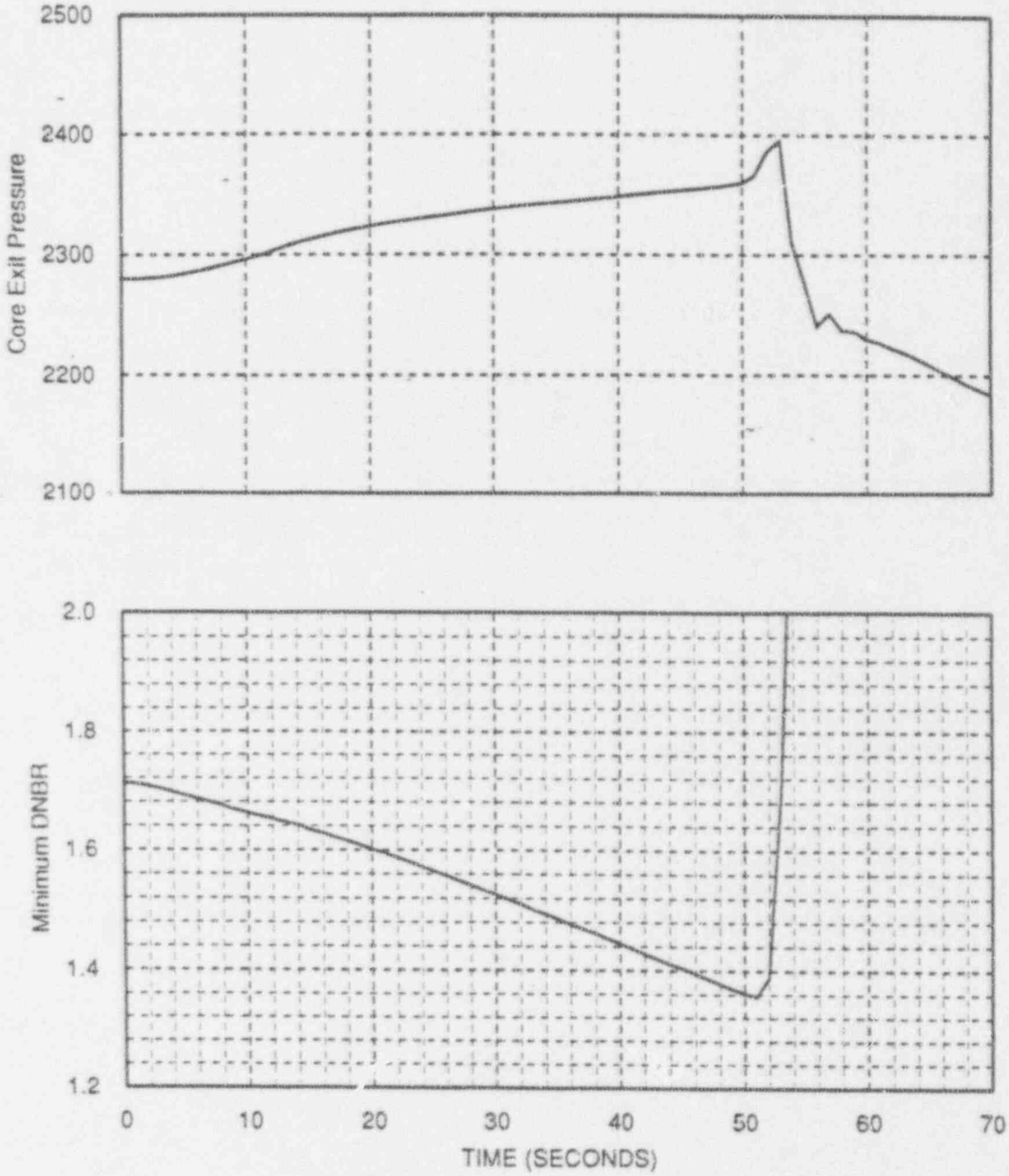
FIGURE 5.4-5 , Sh. 1



Seabrook Station

Uncontrolled RCCA Bank Withdrawal from Full Power with Minimum Reactivity Feedback (03 pcm/sec Insertion Rate)

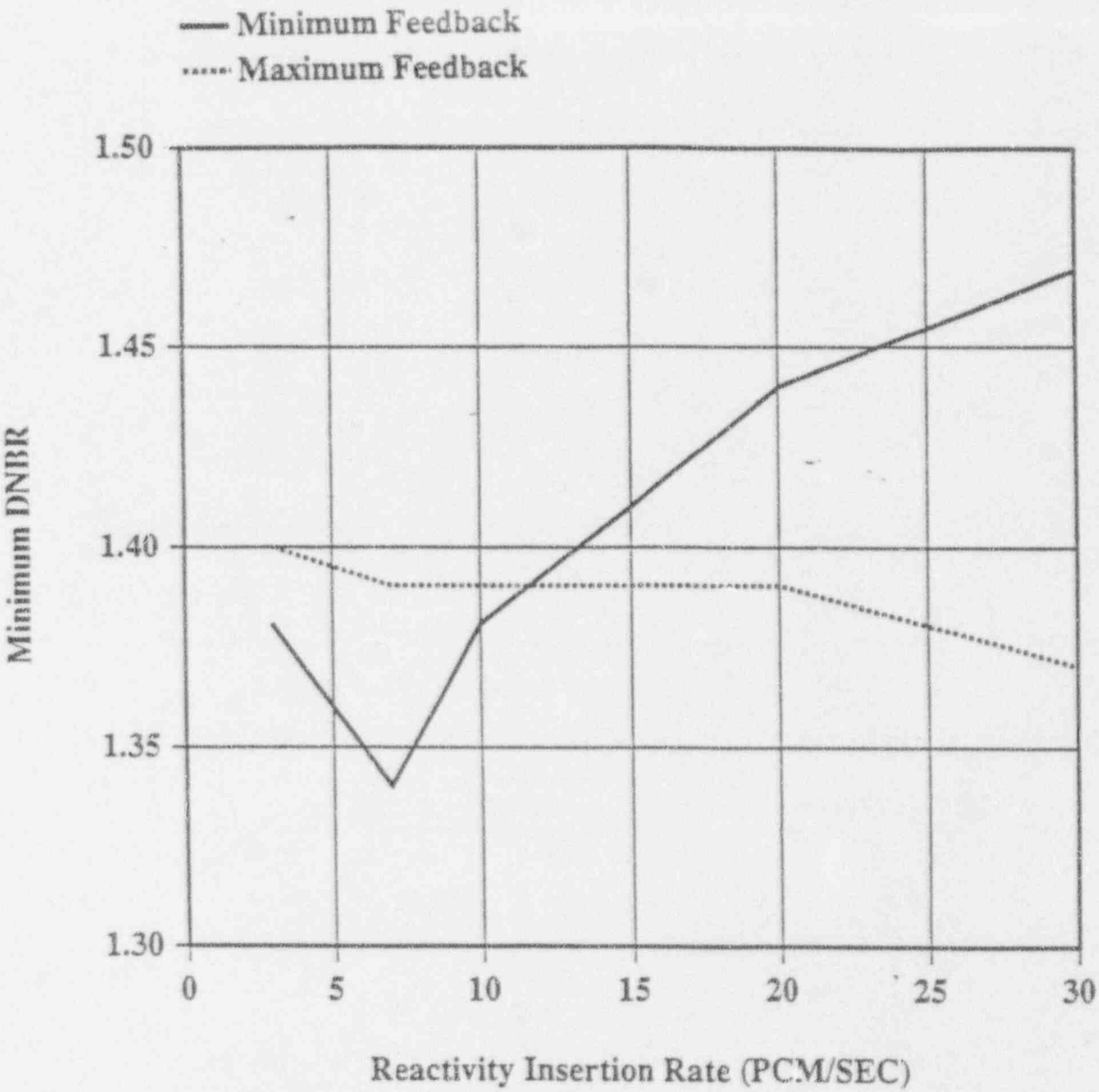
FIGURE 5.4-5 , Sh. 2



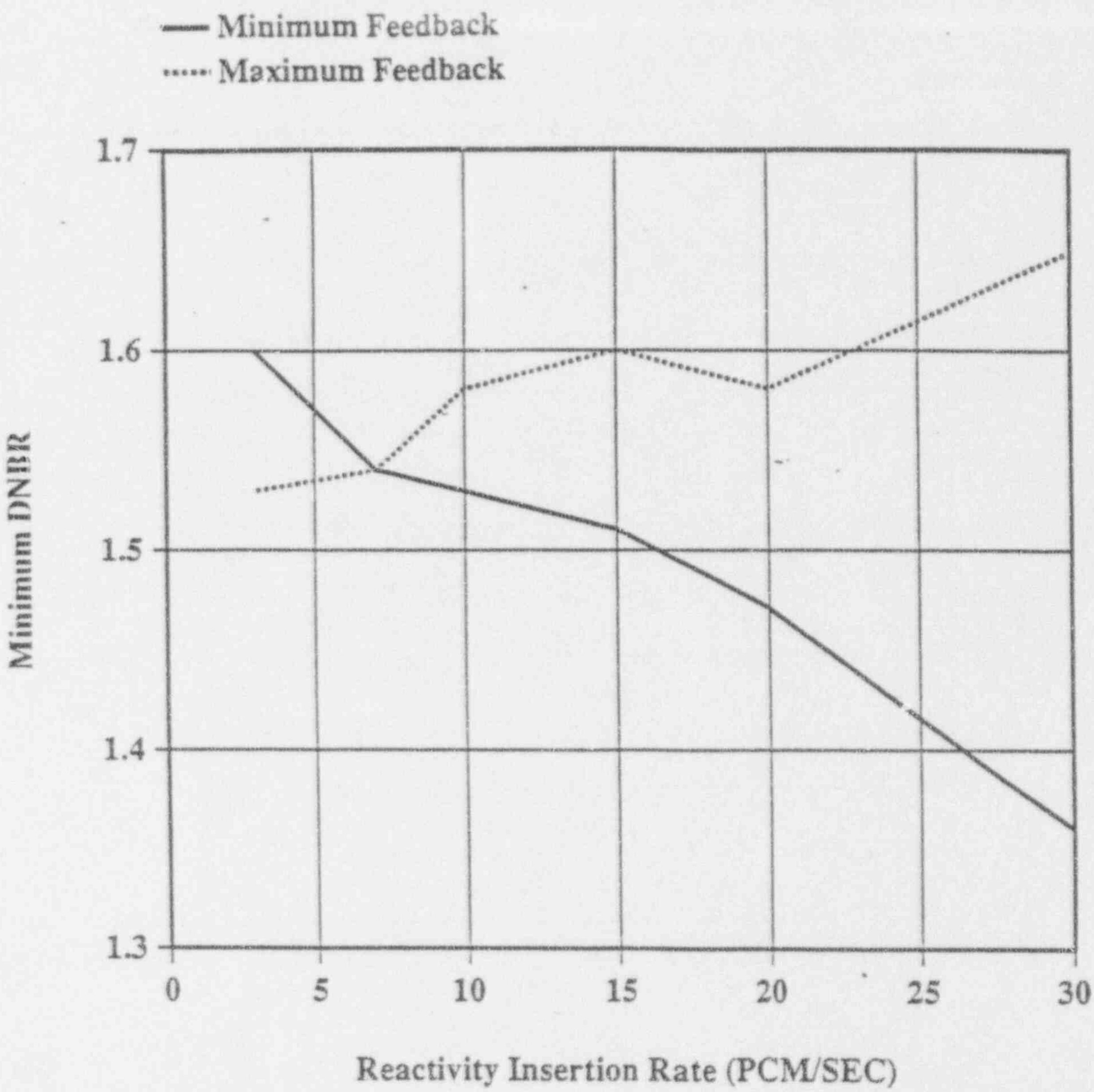
Seabrook Station

Uncontrolled RCCA Bank Withdrawal from Full Power with Minimum Reactivity Feedback (03 pcm/sec Insertion Rate)

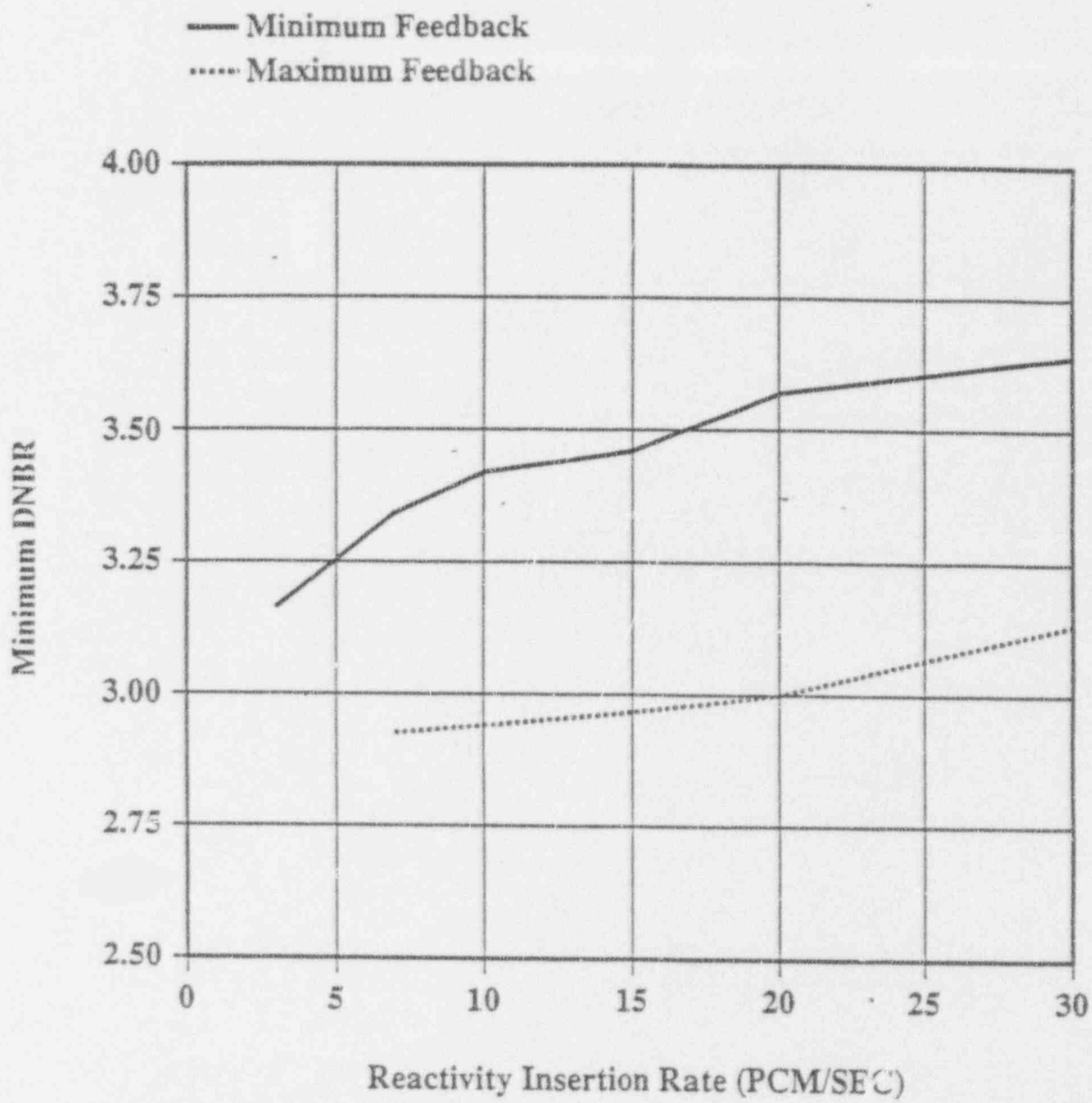
FIGURE 5.4-5 , Sh. 3



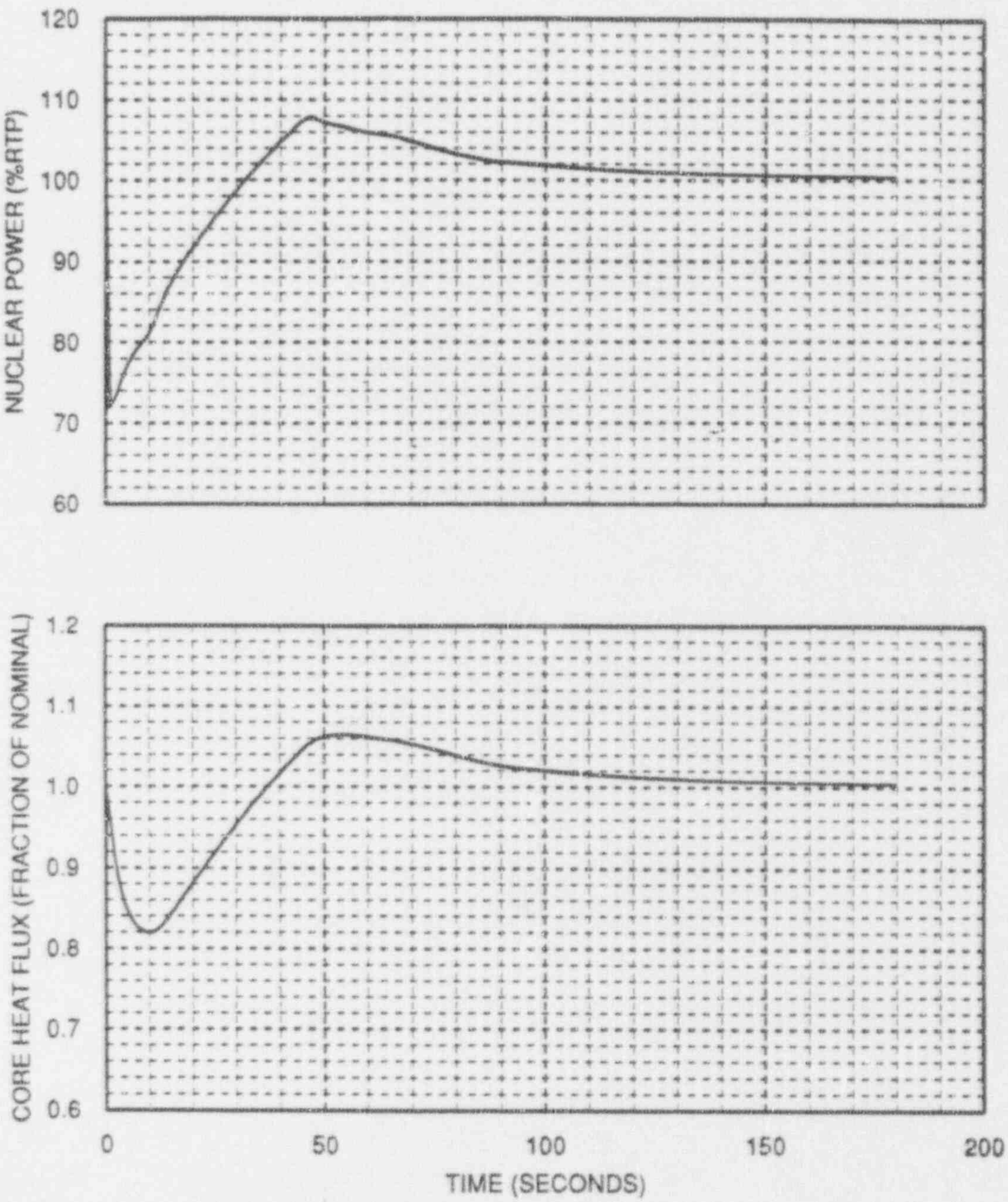
SEABROOK STATION	Minimum DNBR vs. Reactivity Insertion Rates for Rod Withdrawal from 100% Power	
		FIGURE 5.4-6



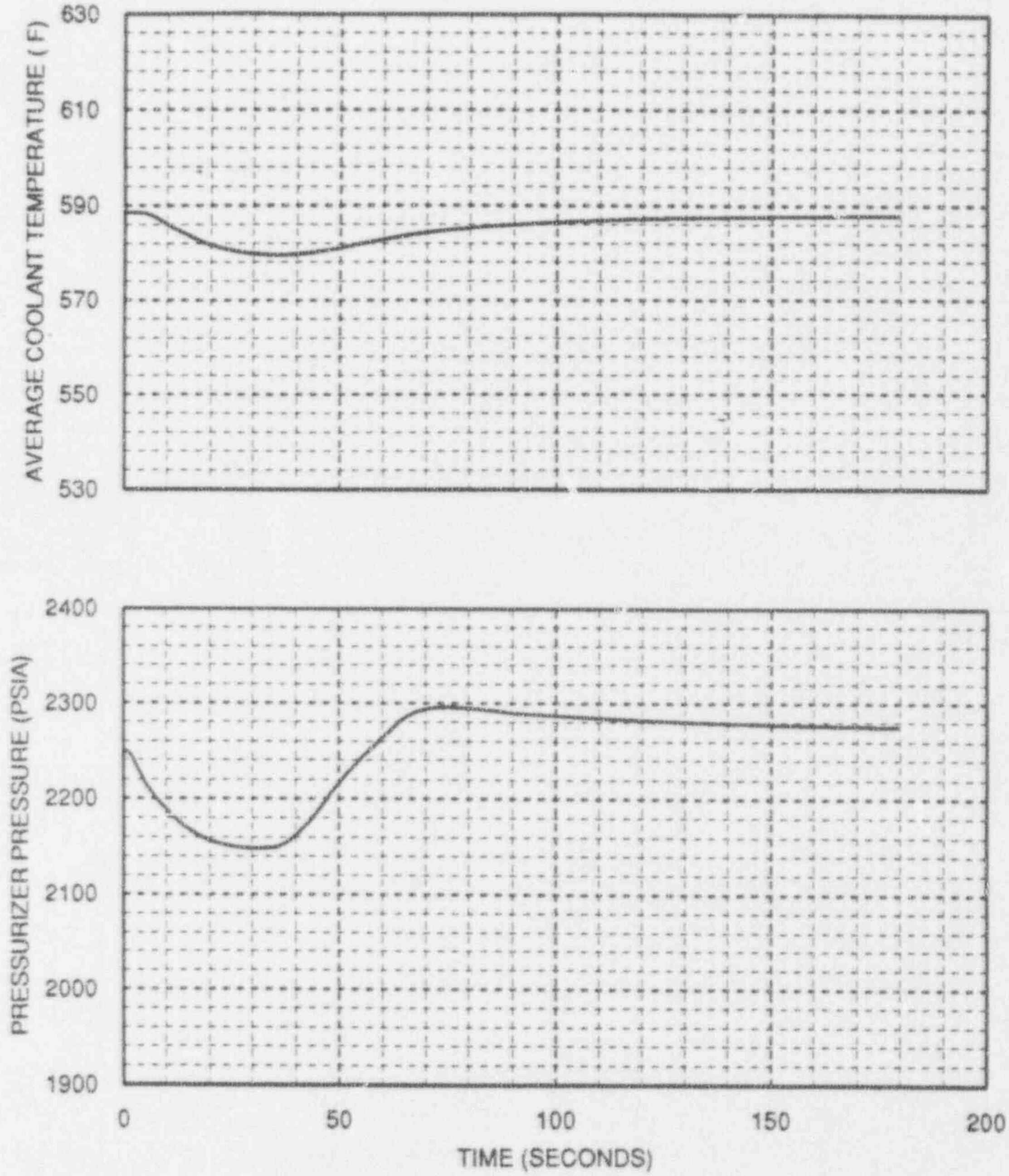
SEABROOK STATION	Minimum DNBR vs. Reactivity Insertion Rate for Rod Withdrawal from 70% Power
	FIGURE 5.4-7



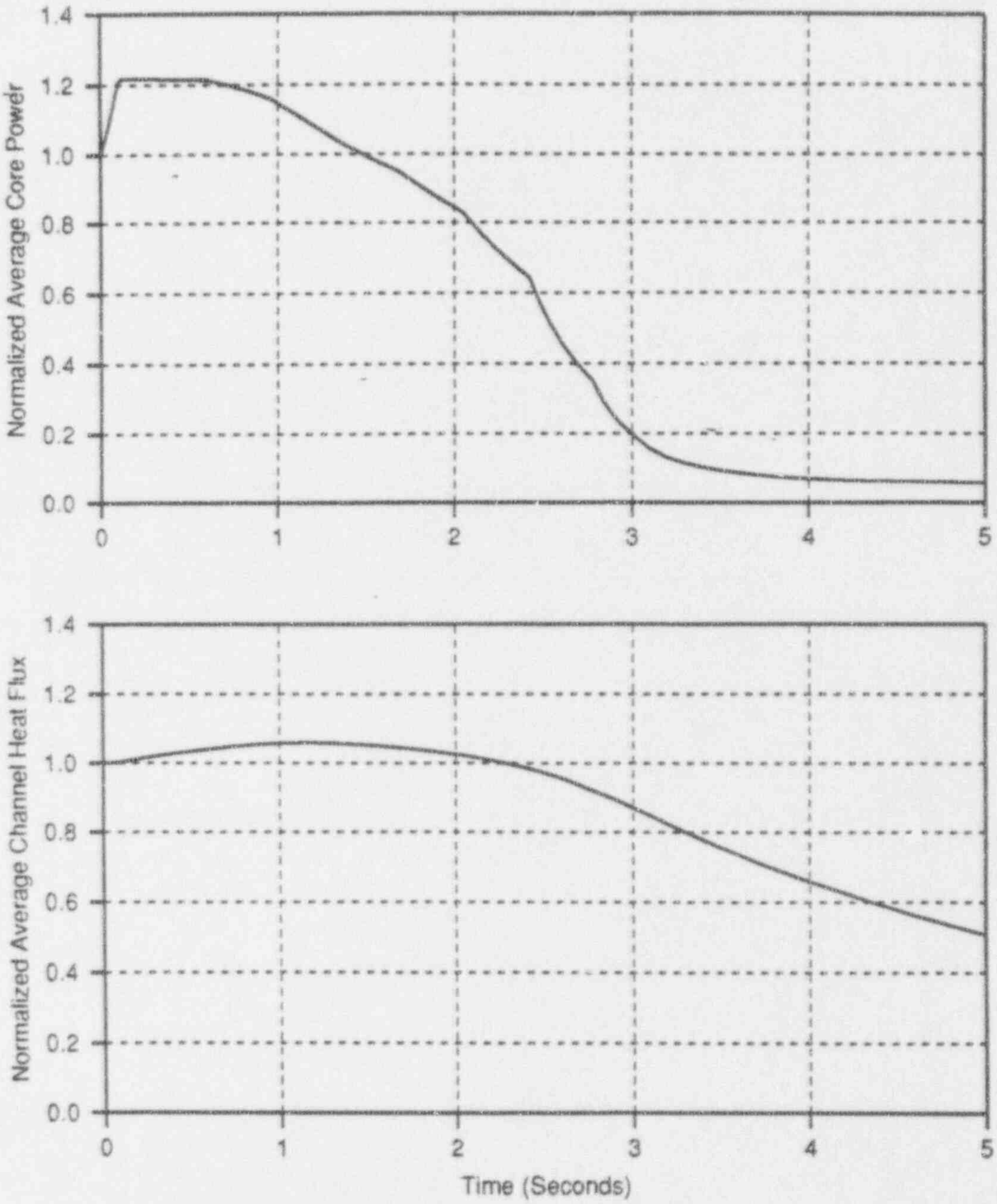
SEABROOK STATION	Minimum DNBR vs. Reactivity Insertion Rate for Rod Withdrawal from 10% Power
	FIGURE 5.4-8



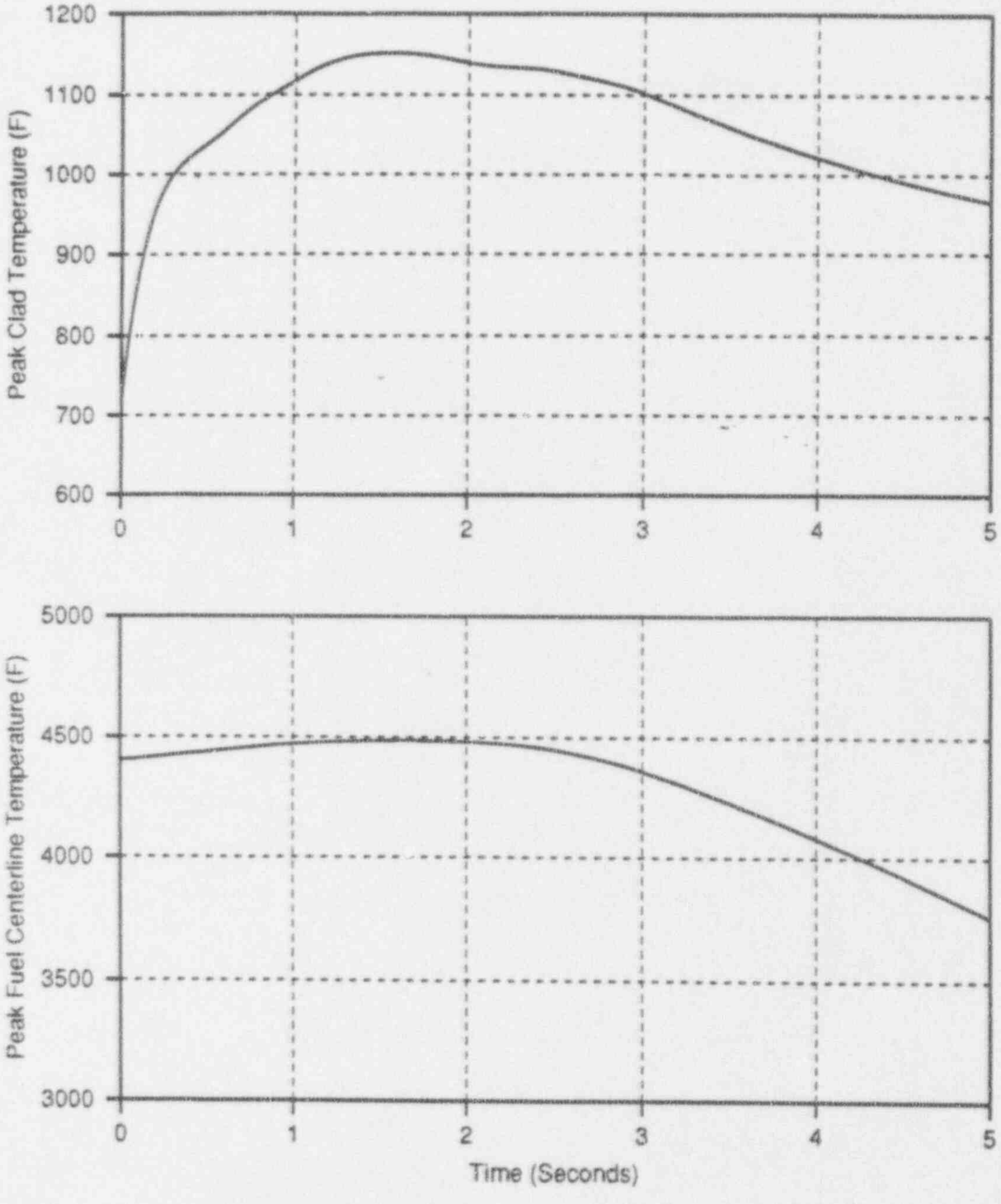
SEABROOK STATION	Dropped Rod Cluster Control Assembly FIGURE 5.4-9 , Sh. 1



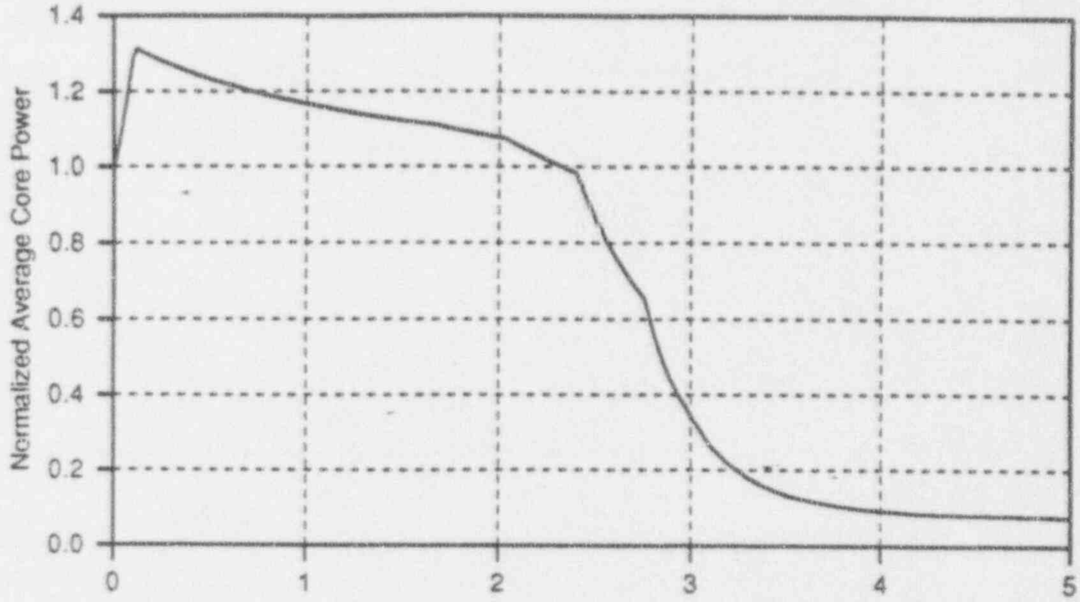
SEABROOK STATION	Dropped Rod Cluster Control Assembly FIGURE 5.4-9 , Sh. 2

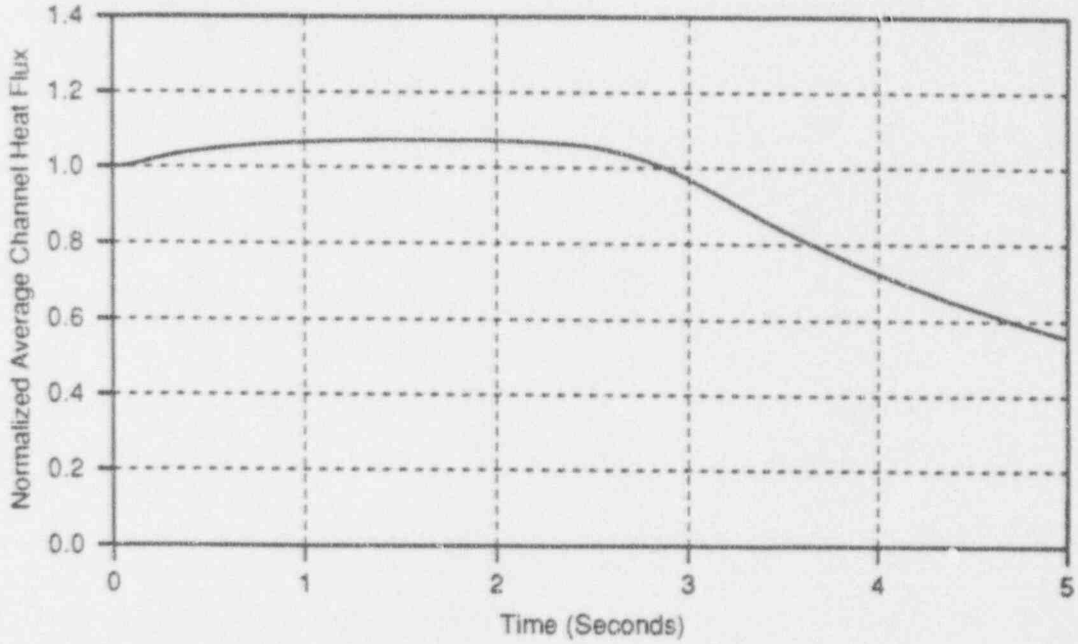


SEABROOK STATION	Control Rod Ejection Full Power, Beginning of Life FIGURE 5.4-10 , Sh. 1

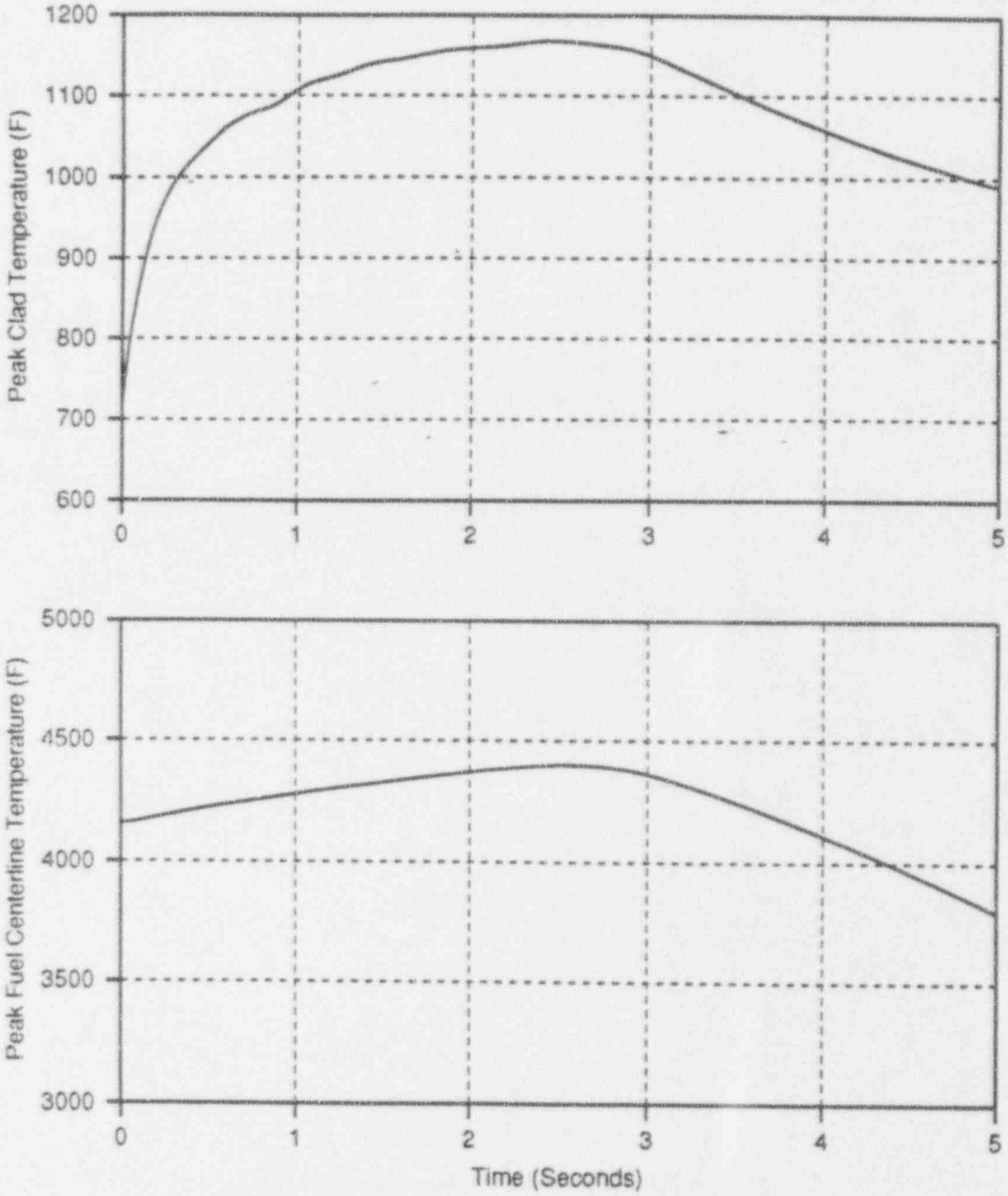


SEABROOK STATION	Control Rod Ejection Full Power, Beginning of Life FIGURE 5.4-10 , Sh. 2





SEABROOK STATION	Control Rod Ejection Full Power, End of Life FIGURE 5.4-11 , Sh. 1



SEABROOK STATION	Control Rod Ejection Full Power, End of Life FIGURE 5.4-11 , Sh. 2

5.5 INCREASE IN REACTOR COOLANT INVENTORY

Discussion of the following events is presented in this section:

a. Inadvertent operation of Emergency Core Cooling System during power operation.

b. Chemical and volume control system malfunction that increases reactor coolant inventory.

These events, considered to be ANS Condition II, cause an increase in reactor coolant inventory. These events are not affected by the changes discussed in Section 3.

5.5.1 Inadvertent Operation of Emergency Core Cooling System during Power Operation

Results of the previous UFSAR analysis show that spurious safety injection without immediate reactor trip presents no hazard to the integrity of the Reactor Coolant System. DNB 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. If the reactor does not trip immediately, the low pressure reactor trip will be actuated. This trips the turbine and prevents excess cooldown thereby expediting recovery from the incident.

The previous UFSAR analysis is not impacted by the changes to input parameters and assumptions discussed in Section 3 of this report. Therefore this event has not been reanalyzed.

5.5.2 Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

Transients due to CVCS malfunctions that increase the reactor coolant inventory can be divided into three categories:

Category 1 CVCS malfunctions that result in the injection of water with a boron concentration greater than the RCS boron concentration.

Category 2 CVCS malfunctions that result in the injection of water with a boron concentration less than the RCS boron concentration.

Category 3 CVCS malfunctions that result in the injection of water with a boron concentration equal to the RCS 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 Subsection 5.5.1. Transients of the type listed in Category 2 are bounded by the "CVCS malfunction that results in a decrease in boron concentration in the reactor coolant" presented in Subsection 5.4.5.

CVCS malfunctions of the type described under Category 3 will not result in any significant nuclear power or RCS temperature transient. A series of bounding cases were previously analyzed in the UFSAR. In all the cases analyzed, core power and RCS average temperature remained relatively unchanged. The results show that none of the operating conditions during the transient approach core limits. The previous UFSAR analyses are not impacted by the changes to input parameters and assumptions discussed in Section 3 of this report. Therefore these events have not been reanalyzed.

5.6 DECREASE IN REACTOR COOLANT INVENTORY

Events which result in a decrease in reactor coolant inventory, as discussed in this section, are as follows:

a. Inadvertent opening of a pressurizer safety or relief valve

b. Break in an instrument line or other nes from the reactor coolant pressure boundary that penetrate Containme.t

c. Steam generator tube failure

d. Loss-of-coolant accident resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary.

Event a has been reanalyzed and results are presented it this section. Events b and c are not affected by the changes discussed in Section 3; they were not reanalyzed. Event d has been reanalyzed by Westinghouse and results are presented in a separate report.

5.6.1 Inadvertent Opening of a Pressurizer Safety or Relief Valve

5.6.1.1 Identification of Causes and Accident Description

An accidental depressurization of the Reactor Coolant System (RCS) could occur as a result of an inadvertent opening of a pressurizer relief 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 RCS are associated with an inadvertent opening of a pressurizer safety valve. Initially the event results in a rapidly decreasing RCS 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 increase power via the moderator density feedback (positive MTC), 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 increases slowly and the pressurizer level increases until reactor trip.

The reactor may be tripped by the following reactor protection system signals:

a. Overtemperature ΔT.

b. Pressurizer low pressure.

An inadvertent opening of a pressurizer safety or relief valve is classified as an ANS Condition II event, a fault of moderate frequency.

5.6.1.2 Analysis of Effects and Consequences

a. Method of Analysis

The accidental depressurization transient is analyzed by employing the detailed digital computer code RETRAN[9]. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

In order to give conservative results in calculating the DNBR during the transient, the following assumptions are made:

1. Initial conditions of maximum core power and reactor coolant temperatures and minimum reactor coolant pressure resulting in the minimum initial margin to DNB.

2. The most positive MTC is assumed.

3. The least negative Doppler coefficient of reactivity is assumed to maximize the power increase prior to the reactor trip.

Normal Reactor Control Systems are not required to function. The Rod Control System is assumed to be in the manual mode to allow the maximum increase in core power prior to the trip. This is a worst case assumption; if the reactor were in automatic control, the rods would insert to offset the increased power and temperature. 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.

Recovery from an inadvertent opening of a PORV would be identical to any other small LOCA accident. This type of LOCA was analyzed in detail in WCAP-9600 "Small Break Analysis in W NSSS Systems." This document provides pressurizer level and system void fraction transient information. The safety systems will prevent any core uncovery, and no operator action is required initially to accomplish this. The operator must eventually switch from RWST injection to cold leg recirculation, similar to any other small LOCA accident.

b. Results

The system response to an inadvertent opening of a pressurizer safety valve is shown on Figure 5.6-1. Nuclear power increases slightly due to the positive MTC until reactor trip occurs on low pressurizer pressure. The steady drop in pressure slows once saturation conditions are reached in the hot leg. The DNBR decreases initially, but increases rapidly following the trip. The DNBR remains above the safety analysis limit value throughout the transient.

The calculated sequence of events for the inadvertent opening of a pressurizer safety valve incident is shown on Table 5.6-1.

5.6.1.3 Radiological Consequences

No radiological consequences have been calculated for this postulated accident since no fuel or clad damage is predicted.

5.6.1.4 Conclusions

The results of the analysis show that the pressurizer low pressure and the Overtemperature ΔT reactor protection system signals provide adequate protection against the RCS depressurization event.

5.6.2 Failure of Small Lines Carrying Primary Coolant Outside Containment

Input parameters and assumptions used in the radiological consequence analysis of this event have not changed from those used in the previous analysis shown in the UFSAR. Previous UFSAR results remain applicable. The doses which have been calculated for the accident of a small line break outside the Containment are within a small fraction of the 10 CFR Part 100 guideline values.

5.6.3 Steam Generator Tube Rupture

An updated analysis of a postulated steam generator tube rupture was previously performed and documented in Reference 28. That analysis remains valid and is incorporated in this report by reference. The offsite doses from a postulated steam generator tube rupture at Seabrook Station are well within the exposure guideline values. Thus, the occurrence of this postulated accident will not result in an undue hazard to the general public.

5.6.4 Loss of Coolant Accidents Resulting From a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

The large and small break Loss-of-Coolant Accident analyses were performed by Westinghouse using current evaluation models, and results are discussed in a separate report. The analyses of both large break and small break accidents have demonstrated margin to all acceptance criteria limits of 10 CFR 50.46 Appendix A, Criterion 19. Input parameters and assumptions used in the radiological consequence analysis of this event have not changed from those used in the previous analysis shown in the UFSAR. Previous UFSAR results remain applicable.

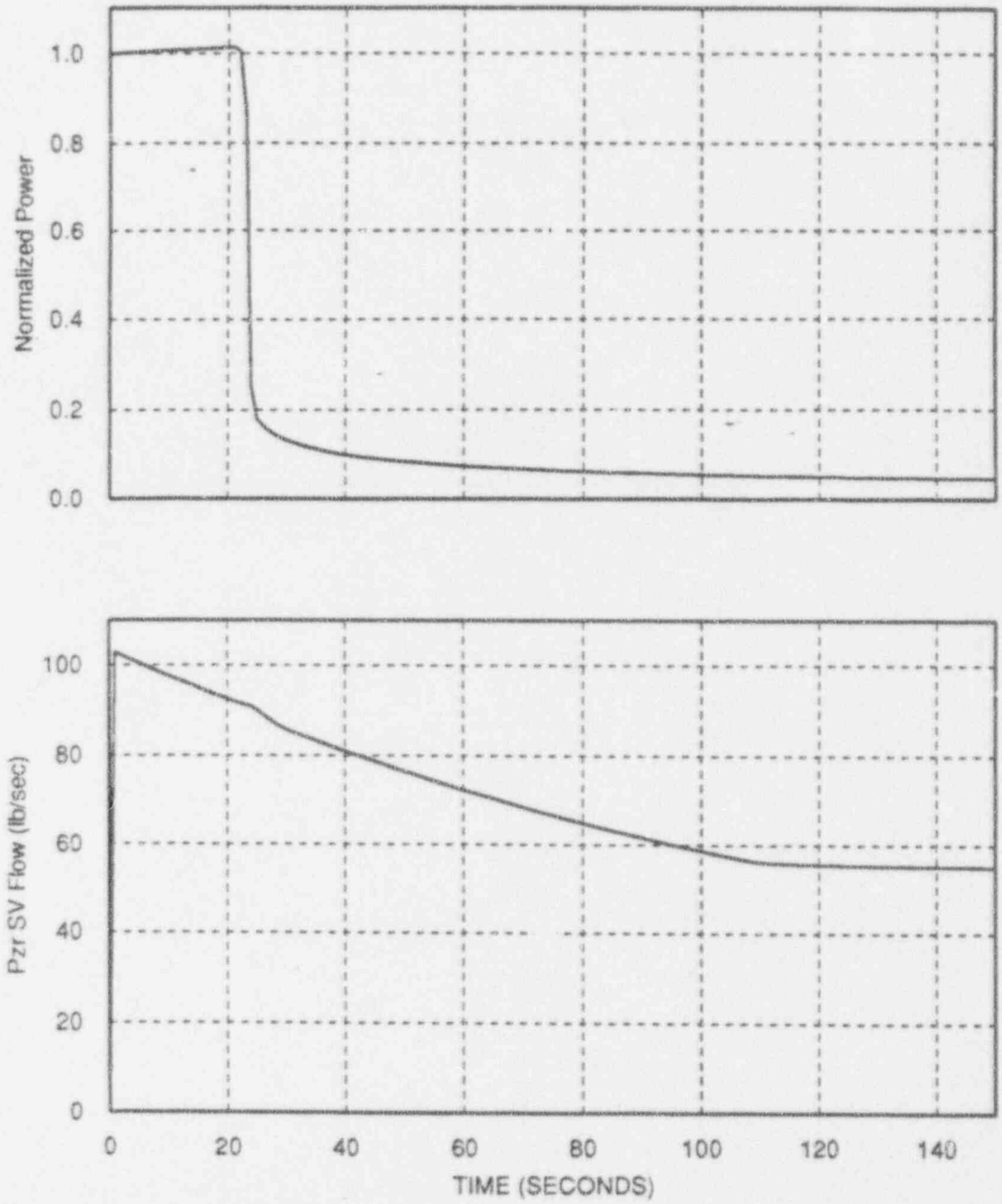
Cycle specific power distributions were generated by Yankee for use in evaluating LOCA sensitivity to axial power distributions consistent with the methodology described in Reference 33. The LOCA analysis results are expressed as an allowable F_Q as a function of core height, as illustrated in Figure 5.6-2. Cycle specific axially dependent limits on peak linear heat generation rates are placed in the Seabrook Station Core Operating Limits Report (COLR).

These limits can be monitored continuously. During periods when the fixed detector system is unavailable, a second set of LCO limits are used. These limits are calculated from the local peaking factors determined from the limiting axial power shape analysis and the most bounding F_Q limits. Predicted values of F_Q's for all possible axial power shapes are ratioed to the F_Q limit and are studied as a function of the axial offset. New limiting LCO bands are determined where predicted F_Q's exceeds the F_Q limit. Surveillance of F_Q must still be performed on a periodic basis, and when the fixed detectors are unavailable, measured F_Q is then increased by a xenon shape weighting factor, W(z). This weighting factor is constructed to insure that F_Q measured during steady state normal operation is corrected by the largest possible increase of F_Q from normal steady state operation to the predicted F_Q of the most adverse xenon conditions.

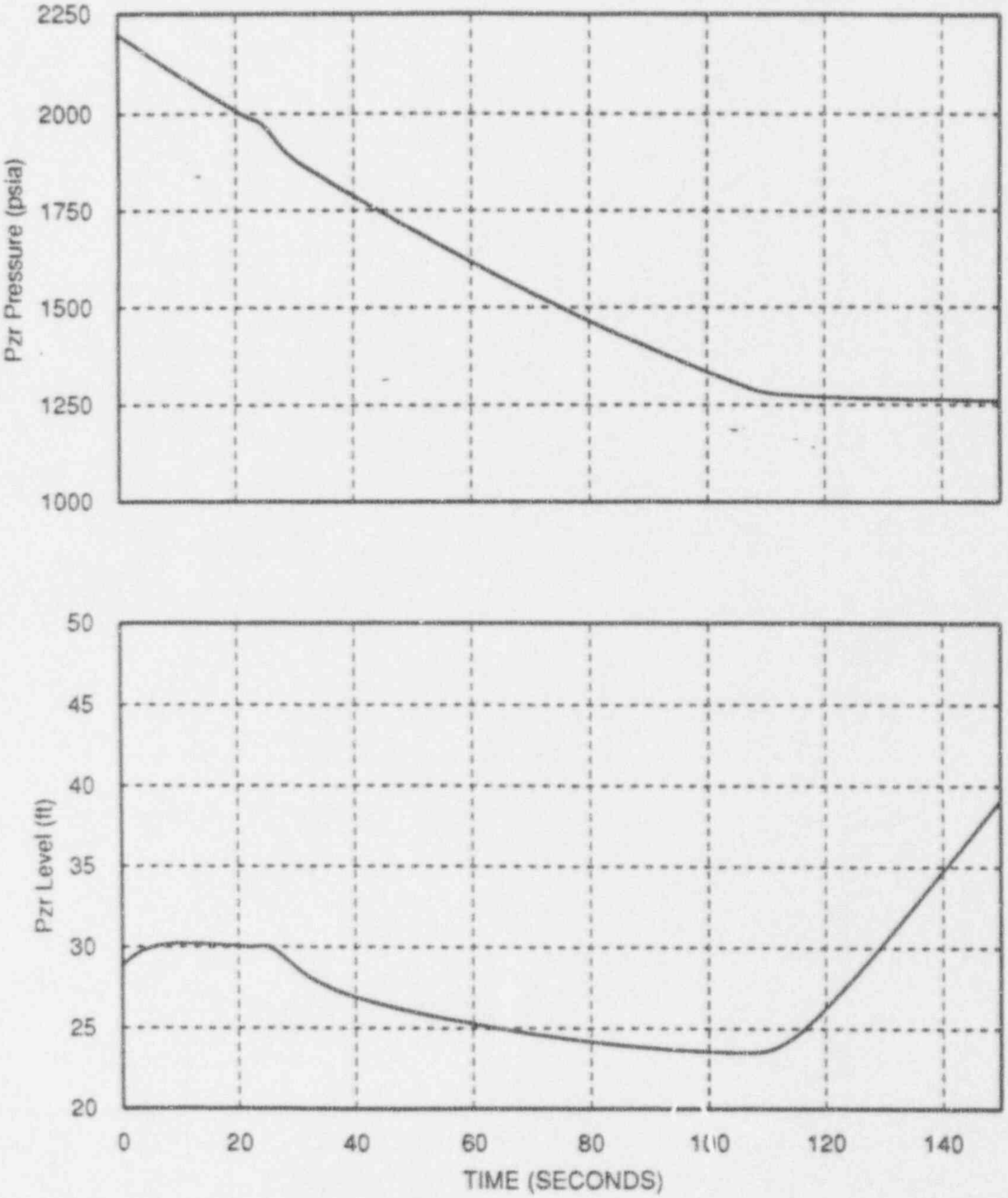
TABLE 5.6-1

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN A DECREASE IN REACTOR COOLANT INVENTORY

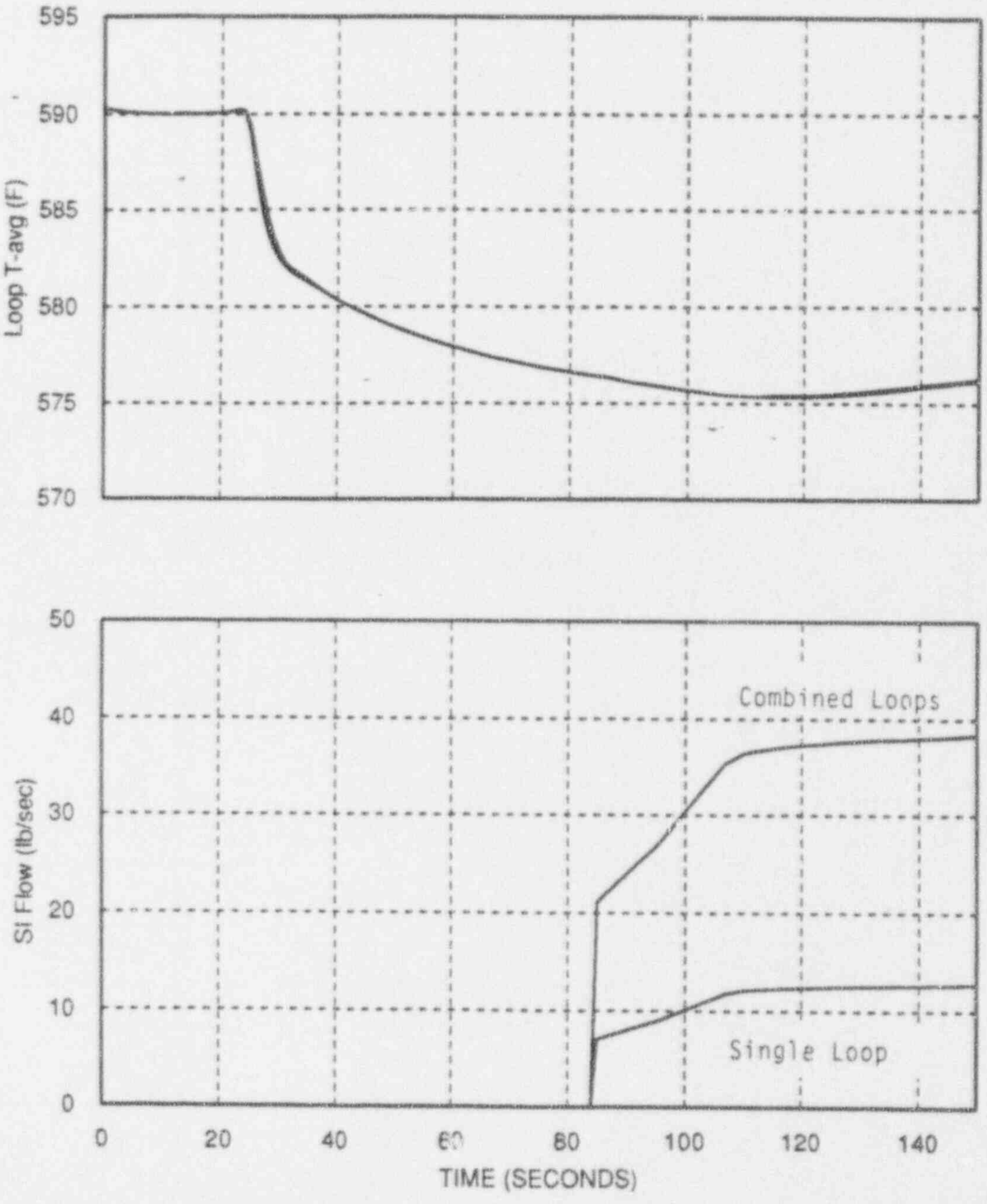
Accident	Event	Time (Seconds)
a. Inadvertent Opening of a Pressurizer Safety Valve	Safety valve opens fully	0
	Low pressurizer pressure reactor trip setpoint reached	19.1
	Rods begin to drop	21.1
	Minimum DNBR occurs	22.0



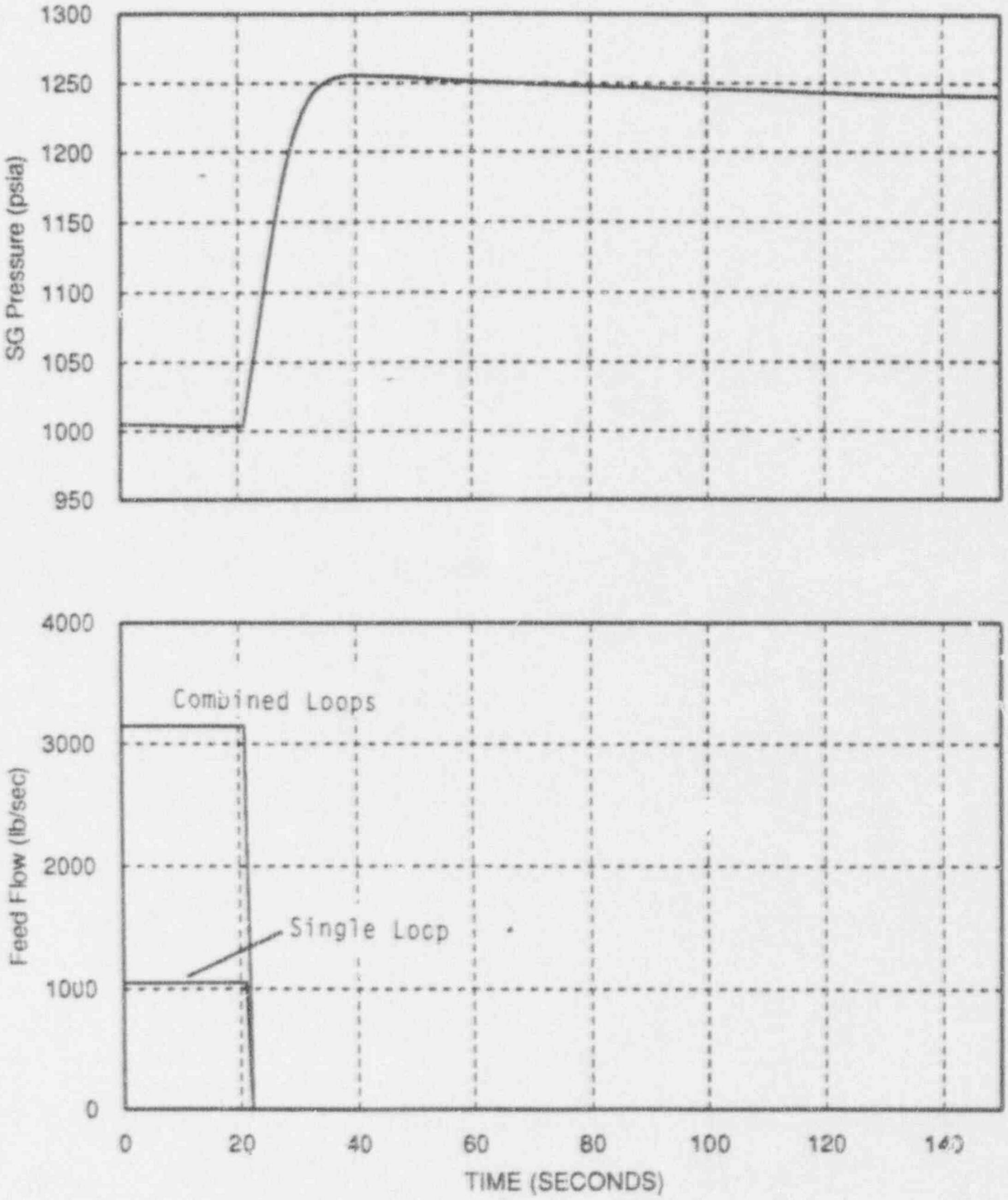
SEABROOK STATION	Inadvertent Opening of a Pressurizer Safety Valve FIGURE 5.6-1 , Sh. 1



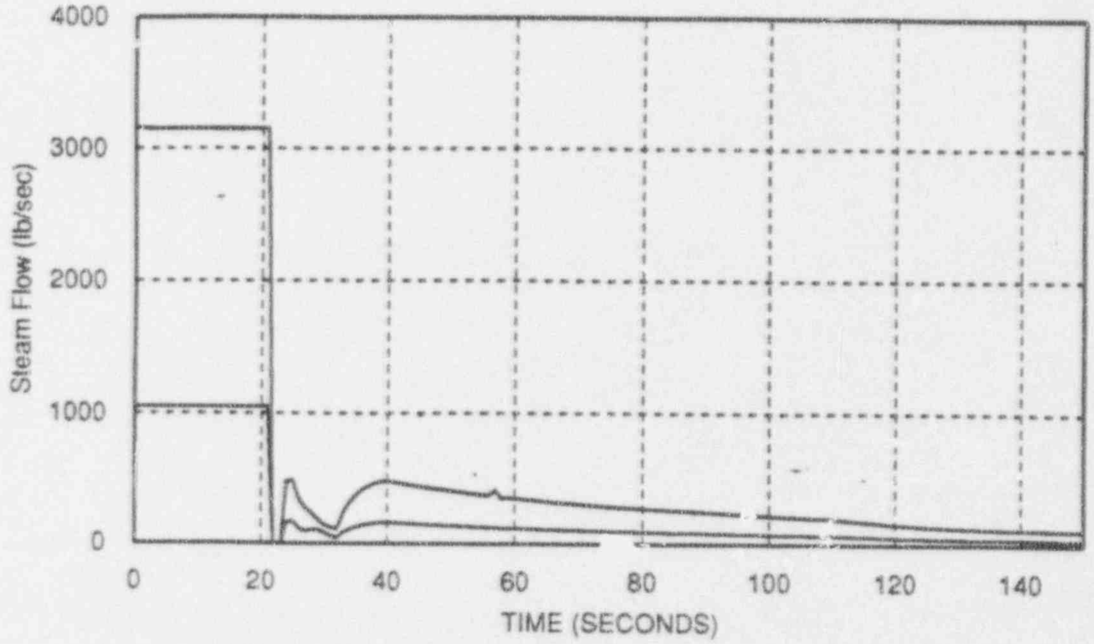
SEABROOK STATION	Inadvertent Opening of a Pressurizer Safety Valve FIGURE 5.6-1 , Sh. 2



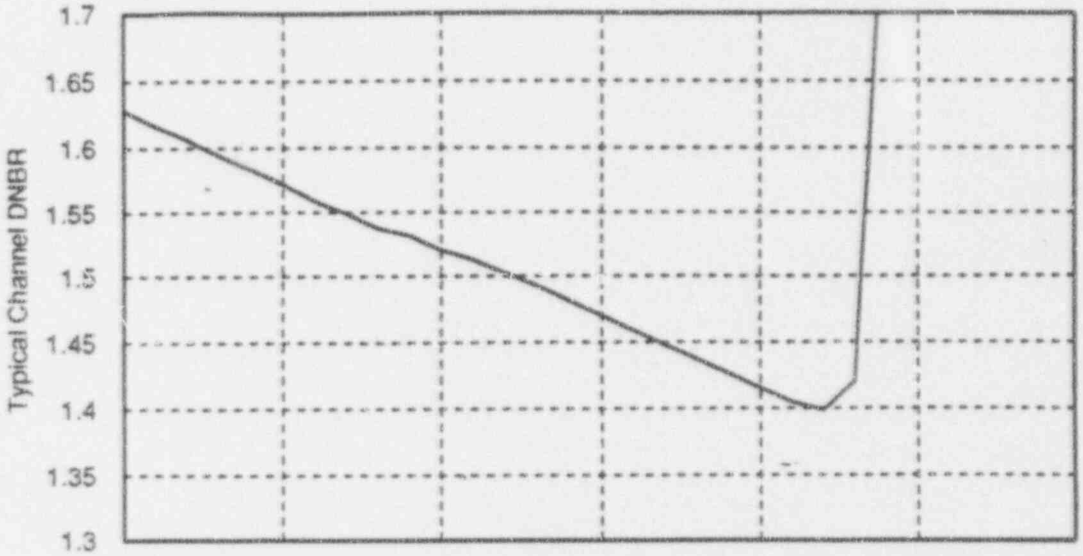
SEABROOK STATION	Inadvertent Opening of a Pressurizer Safety Valve FIGURE 5.6-1 , Sh. 3

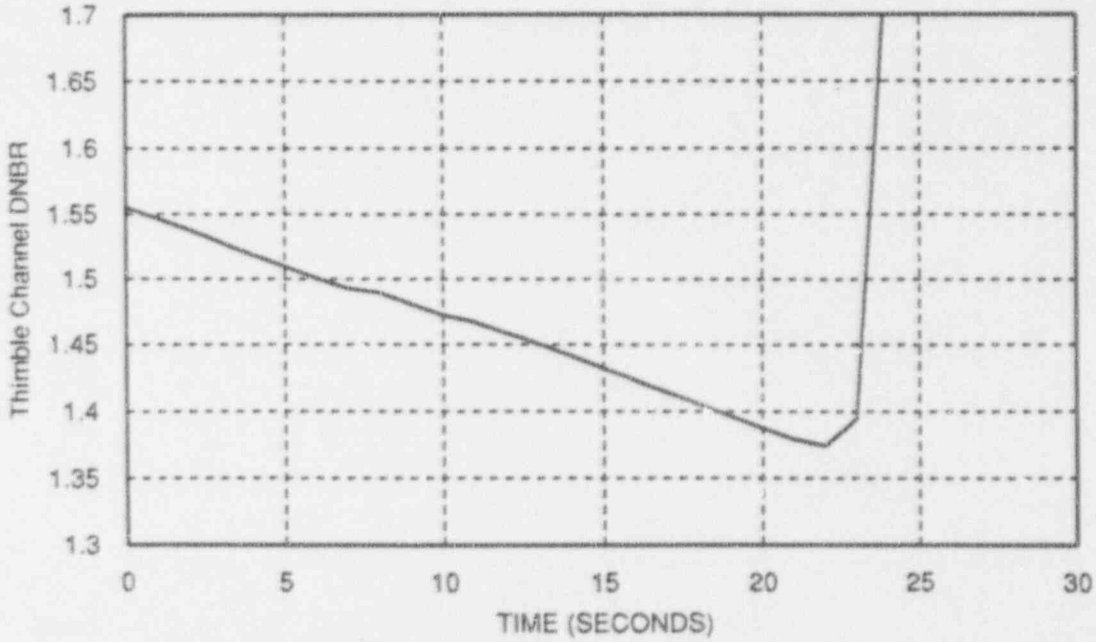


SEABROOK STATION	Inadvertent Opening of a Pressurizer Safety Valve
	FIGURE 5.6-1 , Sh. 4

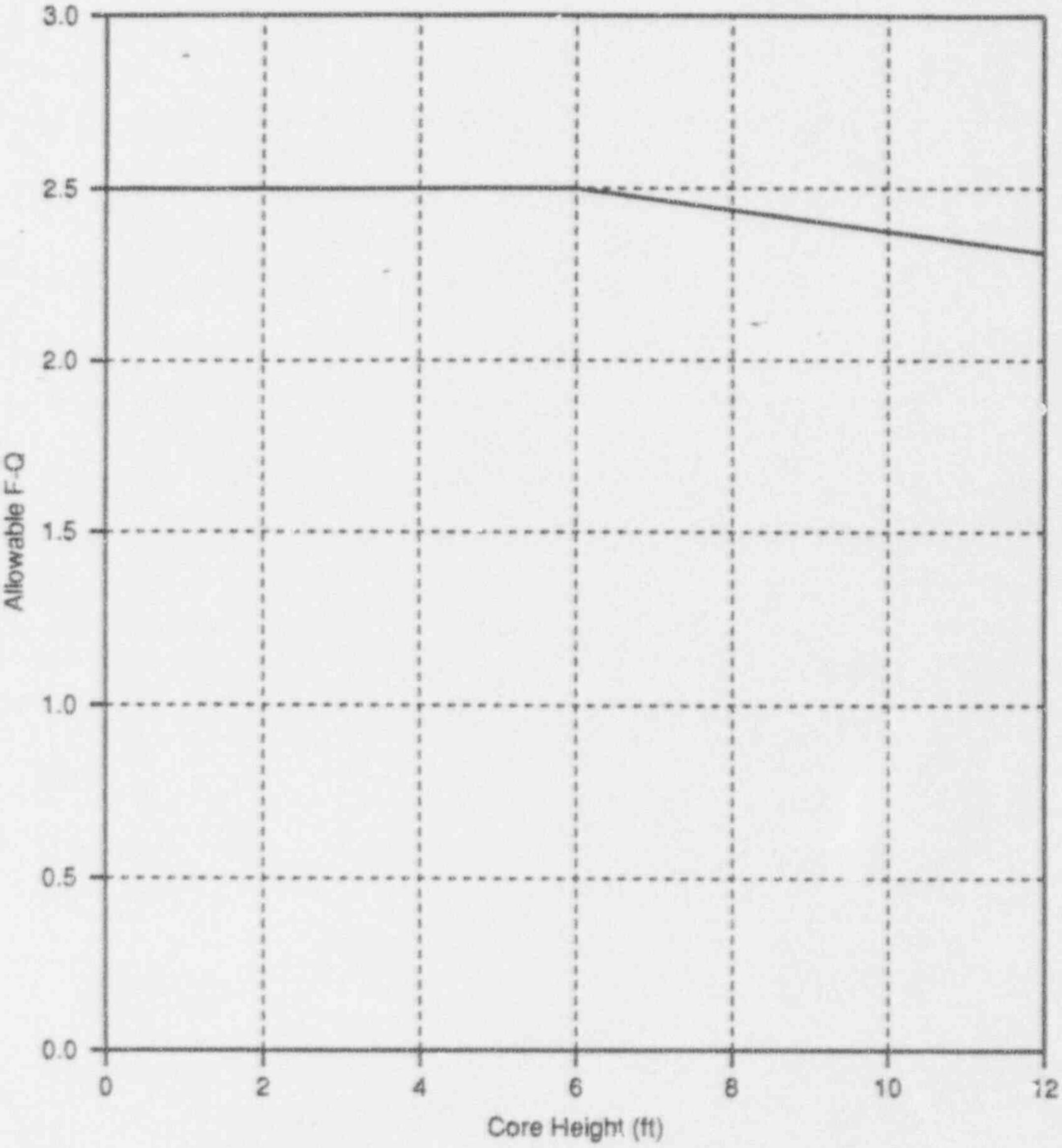


SEABROOK STATION	Inadvertent Opening of a Pressurizer Safety Valve
	FIGURE 5.6-1 , Sh. 5





SEABROOK STATION	Inadvertent Opening of a Pressurizer Safety Valve FIGURE 5.6-1, Sh. 6



SEABROOK STATION	Allowable F-Q vs. Axial Core Height FIGURE 5.6-2

5.7 RADIOACTIVE RELEASE FROM A SYSTEM OR COMPONENT

Input parameters and assumptions used in the radiological consequence analysis of these events have not changed from those used in the previous analyses shown in the UFSAR. Previous UFSAR results remain applicable. No reanalysis is presented in this report.

5.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

A series of generic studies[17,18] on Anticipated Transients Without Scram (ATWS) showed acceptable consequences would result provided that the turbine trips and emergency feedwater flow is initiated. The information presented in References 17 and 18 is applicable to Seabrook. The effects of ATWS events are not considered as part of the design basis for transients analyzed in UFSAR Chapter 15. The final NRC ATWS rule[19] requires that Westinghouse designed plants install ATWS mitigation systems to initiate a turbine trip and actuate emergency feed water flow independent of the Reactor Protection System. The Seabrook ATWS mitigation system is described in UFSAR Subsection 7.6.12.

The Seabrook Station licensee and Yankee have performed a reassessment of ATWS risk in support of the SSPSS-93 update[22] which demonstrates continuing compliance with the NRC ATWS rule[19] and the basis for the rule by exhibiting ATWS core damage frequency below the target of 1.0×10^{-5} per reactor year established in Reference 20. The impact of the changes discussed in Section 3 of this report on ATWS core damage frequency were reassessed using the information and guidance provided in Reference 21.

6.0 CONCLUSIONS

This report provides a revised Seabrook Station safety analysis for supporting 1) operation with an expanded axial flux difference Limiting Condition for Operation band, and 2) revised cycle design parameters. These benefits are obtained for Seabrook Station through 1) use of the information available from the Fixed Incore Detector System to continuously monitor core performance, 2) implementation of improved fuel design features, and 3) application of Yankee safety analysis methodologies which were previously reviewed and approved by the Nuclear Regulatory Commission. Results of the safety analysis documented in Sections 4 and 5 demonstrate that Seabrook Station can be safely operated within Technical Specifications including the proposed changes discussed in Section 3. Margins to safety as defined in the bases to the Seabrook Station Technical Specifications are not reduced by these changes.

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