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Subject: Arkansas Nuclear One - Unit 2
Docket No. 50-368
License Nos. NPF-6
Proposed Technical Specification Changes And Resolution of Unreviewed Safety Question Associated With Applicable Limits And Setpoints Supporting Steam Generator Replacement

Gentlemen:

Attached for your review and approval are proposed changes to the Arkansas Nuclear One – Unit 2 (ANO-2) Technical Specifications (TS). The proposed changes affect ANO-2 Limiting Conditions for Operation, Safety Limit Settings, and associated bases that are impacted by the design and installation of the replacement steam generators (RSG), and the subsequent proposed power uprate from 2815 MWt to 3026 MWt. The RSGs are currently scheduled for installation in the fall of 2000. The affected TS values will be changed to support this installation, ensuring continued safe operation of the unit within acceptable limits following RSG installation. In addition, small increases in offsite doses, conservatively concluded to involve an Unreviewed Safety Question (USQ), will be addressed in this submittal. Also, included in this submittal are associated figures, tables, and changes to the ANO-2 SAR that support the bases associated with the new TS values and radiological dose considerations.

The existing, original steam generators (OSGs) at ANO-2 have degraded due to various corrosion-related phenomena. Several of the tubes within the OSGs have consequently been removed from service in order to ensure a reliable primary-to-secondary boundary, thereby establishing prolonged protection of the health and safety of the public. Due to this degradation, several operating parameters have been adjusted to assure continued safe operation considering the reduced heat transfer area and Reactor Coolant System (RCS) volume due to tube plugging. The combined effect has been an overall degradation of the efficiency of the unit. To regain this efficiency and restore the primary-to-secondary boundary within the steam generators, Entergy Operations, Inc. has initiated efforts to purchase and install RSGs. ANO-2 is scheduled to operate for one cycle (Cycle 15) following installation of the RSGs at its current licensed power level (2815 MWt). During Cycle 15, license amendments will be submitted for NRC review to increase the rated thermal power 7.5%, to become effective for the following operational cycle (Cycle 16).

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The RSGs are a Westinghouse design, whereas the OSGs were designed by Combustion Engineering. The new design has provided several enhancements to operational efficiencies and has resulted in several changes compared to the OSGs. These differences have required reanalysis of related Design Basis Accidents and subsequently resulted in the need for the revision of several TS limits. Included in the assessments are the radiological dose changes at the Exclusion Area Boundary and Low Population Zone which have increased slightly, largely due to more conservative analysis assumptions that have been applied.

The proposed changes have been evaluated in accordance with 10 CFR 50.91(a)(1) using criteria in 10 CFR 50.92(c) and it has been determined that these changes involve no significant hazards considerations. The bases for these determinations are included in the attached submittal.

Copies of the proposed TS changes, the TS markup pages, proposed USQ-related SAR changes and markups, and the respective analyses supporting RSG installation and power uprate are included in this submittal.

Entergy Operations, Inc. requests approval of the proposed changes by September 1, 2000, to be implemented prior to startup from the next ANO-2 refueling outage, 2R14.

Very truly yours,

C. Randy Hutchinson

CRH/dbb
Attachment/Enclosures

To the best of my knowledge and belief, the statements contained in this submittal are true.

SUBSCRIBED AND SWORN TO before me, a Notary Public in and for Pope **County and the State of Arkansas, this** 29 **day of** November**, 1999.**

Andrea Pierce

Notary Public
My Commission Expires 12/15/2007

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ATTACHMENT 1

TO

2CAN119901

PROPOSED TECHNICAL SPECIFICATION

AND

RESPECTIVE SAFETY ANALYSES

IN THE MATTER OF AMENDING

LICENSE NO. NPF-6

ENTERGY OPERATIONS, INC.

ARKANSAS NUCLEAR ONE, UNIT TWO

DOCKET NO. 50-368

DESCRIPTION OF PROPOSED CHANGES

The proposed changes to the Arkansas Nuclear One, Unit 2 (ANO-2) Technical Specifications (TS) are required to maintain consistency with the transient and accident analyses which evaluated the impact of the replacement steam generators (RSGs) that are being installed for Cycle 15 operation. The following changes are proposed:

- Decrease the Pressurizer Pressure – Low setpoint of Table 2.2-1, "Reactor Protective Instrumentation Trip Setpoint Limits," on page 2-5 from ≥ 1717.4 psia to ≥ 1675 psia and its allowable value from ≥ 1686.3 psia to ≥ 1643.9 psia. In addition, the allowable value is removed from the bases on page B 2-4.

- Increase the Steam Generator Pressure – Low setpoint of Table 2.2-1, "Reactor Protective Instrumentation Trip Setpoint Limits," on page 2-5 from ≥ 712 psia to ≥ 751 psia and its allowable value from ≥ 699.6 psia to ≥ 738.6 psia.

- Decrease the Steam Generator Level – Low setpoint of Table 2.2-1, "Reactor Protective Instrumentation Trip Setpoint Limits," on page 2-5 from ≥ 23% to ≥ 22.2% and its allowable value from ≥ 22.111% to ≥ 21.5%.

- Items 2b, 2c, and 2d of Table 2.2-1, along with the footnote at the bottom of the page are being deleted as part of a page cleanup effort. No plans currently exist for ANO-2 to address startup and/or power operation with less than four reactor coolant pumps (RCPs) operating. Therefore, the aforementioned items have been deleted. No further discussion will be presented in this submittal regarding this change.

- Return the required reactor coolant system (RCS) flow rate of TS 3.2.5, "RCS Flow Rate," on page 3/4 2-7 from 108.4 x 10^6 lbm/hr to its original value of 120.4 x 10^6 lbm/hr and delete Note 1.

- Decrease the Pressurizer Pressure – Low setpoint of Item 1c of Table 3.3-4, "Engineered Safety Feature Actuation System Instrumentation Trip Values," on page 3/4 3-16 from ≥ 1717.4 psia to ≥ 1675 psia and its allowable value from ≥ 1686.3 psia to ≥ 1643.9 psia.

- Increase the Steam Generator Pressure – Low setpoint of Table 3.3-4, Item 4b, "Engineered Safety Feature Actuation System Instrumentation Trip Values," on page 3/4 3-17 from ≥ 712 psia to ≥ 751 psia and its allowable value from ≥ 699.6 psia to ≥ 738.6 psia.

- Decrease the Pressurizer Pressure – Low setpoint of Item 5c of Table 3.3-4, "Engineered Safety Feature Actuation System Instrumentation Trip Values," on page 3/4 3-17 from ≥ 1717.4 psia to ≥ 1675 psia and its allowable value from ≥ 1686.3 psia to ≥ 1643.9 psia.

- Decrease the Steam Generator (A&B) Level – Low setpoint of Item 8b of Table 3.3-4, "Engineered Safety Feature Actuation System Instrumentation Trip Values," on page 3/4 3-18 from ≥ 23% to ≥ 22.2% and its allowable value from ≥ 22.111% to ≥ 21.5%. Note (3), which is applicable to this setpoint, is clarified as a *narrow range* instrument.

- Increase the Steam Generator (A&B) Pressure – Low setpoint of Item 8e of Table 3.3-4, "Engineered Safety Feature Actuation System Instrumentation Trip Values," on page 3/4 3-18 from ≥ 712 psia to ≥ 751 psia and its allowable value from ≥ 699.6 psia to ≥ 738.6 psia.

- In the footer of page 3/4 3-18 (discussed above), the next page is referenced as being 3/4 3-21 and remove pages 3/4 3-19 and 3/4 3-20 from the TSs. The two pages are currently intentionally left blank. No further discussion will be presented in this submittal regarding this change.

- Action (a) of Specification 3.7.1.1 is revised to allow up to 12 hours to reduce the High Linear Power Level – High Trip setpoint in accordance with Table 3.7-1 when one or more main steam safety valves (MSSVs) are inoperable. In addition, this action has been revised to be applicable in Modes 1 and 2 only. The shutdown requirement of this action has also been revised to require a shutdown to Mode 4 within an additional 12 hours instead of to Mode 5 conditions within an additional 30 hours. This change provides consistency with the Revised Standard Technical Specifications (RSTS). A discussion is also added to the basis of this specification on page B 3/4 7-1.

- As referenced above during discussion of operation with less than four RCPs, Action (b) of TS 3.7.1.1, "Safety Valves" on page 3/4 7-1 has been changed to delete reference to operation in Modes 1 or 2. The requirements of Action Item (b) refer only to those modes of operation where less than four RCPs are in operation. As discussed previously, ANO-2 currently does not plan to evaluate operation in the startup or power operation modes with less than four RCPs in operation. Therefore, reference to this configuration has been deleted. The Action (b) requirement concerning the Linear Power Level – High Trip setpoints is deleted since its purpose was to provide added protection when operating in Modes 1 and 2. The requirement two operable MSSVs on the non-operating steam generator is maintained for Mode 3 conditions. In addition, the proposed change requires the operating steam genertor to also have to operable MSSVs in accordance with the ASME code, regardless of the number of operating loops. This change, therefore, is more restrictive. As in Action (a) above, the shutdown statement has been revised to refer to Mode 4 instead of Mode 5 conditions with the same transition period allowed as for Action (a).

- TS Table 3.7-1, "Maximum Allowable Linear Power Level-High Trip Setpoint With Inoperable Steam Line Safety Valves During Operation With Both Steam Generators," on page 3/4 7-2 has been changed to reflect new allowable values for the Linear Power Level – High Trip setpoint during operation with one or more MSSVs inoperable. For conditions where an individual MSSV or a maximum of one MSSV is inoperable per steam generator, the user is referred to a moderator temperature coefficient (MTC) versus rated thermal power curve to determine the appropriate High Linear Power Trip setpoint.

  The application of this new TS curve provides somewhat higher setpoint criteria than would be allowed in the absence of considering MTC effects. For other MSSV inoperability configurations, the following limits will apply:

  1. Where no more than two MSSVs are inoperable on each steam generator, the High Linear Power Trip setpoint is decreased from 67.7% to 43% rated thermal power.

  2. Where no more than three MSSVs are inoperable on each steam generator, the High Linear Power Trip setpoint is decreased from 36% to 25% rated thermal power. More than three inoperable MSSVs on any steam generator will require the unit to be placed in Hot Standby within 6 hours and Cold Shutdown within the following 30 hours.

- TS Table 3.7-2, "Maximum Allowable Linear Power Level-High Trip Setpoint With Inoperable Steam Line Safety Valves During Operation With One Steam Generator," on page 3/4 7-3 has been deleted since current plans at ANO-2 do not include evaluating operating in the startup or power operations mode with less than 4 RCPs in operation. No further discussion will be presented in this submittal regarding this change.

- New TS Figure 3.7-1, "MTC Versus High Linear Power Trip Setpoint," has replaced the deleted Table 3.7-2 on page 3/4 7-3 to provide a comparison of the percent of rated power versus the MTC as a method of determining the value for the Linear Power Level – High Trip setpoint during periods when a MSSV(s) is inoperable.

- Bases 3/4.7.1.1, Safety Cycles, for the MSSVs out of service on page B 3/4 7-1 has been updated to reflect the Loss of Condenser Vacuum (LOCV) event as the limiting event for defining the High Linear Power Trip setpoints. The title has also been changed to "Safety Valves" to be consistent with the title of TS 3.7.1.1 with which it is associated. The reference to "1100 psia" of the first paragraph is deleted to prevent misleading the reader (RSG is designed for 1100 psig, secondary system is designed for 1100 psia). The proposed change will also eliminate the linear power reduction relationship listed in the Bases and state that the acceptability with MSSVs inoperable will be determined by the initial power level assumed in the LOCV event. Additionally, a new methodology relating to the comparison of MTC versus power level has been included in the bases.

Evaluation of some accident modes that are impacted by the installation of the RSGs resulted in a small increase in offsite dose consequences. The slight increases in dose have been conservatively concluded to be an Unreviewed Safety Question (USQ) in accordance with 10 CFR 50.59(a)(2). Therefore, several revisions to the ANO-2 Safety Analysis Report (SAR) are required, specifically SAR Chapter 15, "Accident Analysis." The associated revisions are included in this submittal for the NRC staff's review.

Other parameters and components also require change as a result of RSG installations other than those proposed above. The Steam Generator High Level Trip setpoint is an example of another Reactor Protective System (RPS) change that will result from operation with the RSGs. However, because the purpose of this trip does not support protection of the reactor core and subsequently the health and safety of the public, ANO-2 intends a separate submittal (2CAN119905 scheduled November 29, 1999) to discuss changes associated with the Steam Generator High Level Trip setpoint. Another area of impact concerns the design rating of the containment building and other related components. The issues associated with the containment building are currently addressed in ANO-2 letter 2CAN119903, dated November 3, 1999. Therefore, the purpose of this submittal will remain limited to primarily RPS-related instrumentation setpoint changes, along with changes to RCS flow limits and operation with inoperable MSSVs. Additionally, Enclosures 3 and 4 will provide evaluational insights concerning pre-analyzed loss of coolant accident (LOCA) and non-LOCA events that may be impacted by operation with the RSGs.

The following sections will provide information and bases for the aforementioned changes. Four enclosures are included:

Enclosure 1: Technical Specifications

1. Proposed ANO-2 Technical Specifications Changes
2. Markups of Current ANO-2 Technical Specifications (for information only)

Enclosure 2: Safety Analysis Report

1. Markups of the Current ANO-2 Safety Analysis Report (for information only)

Enclosure 3: ECCS Performance Analysis

1. Impact of RSG Installation on ECCS Performance Criteria
2. Tables 1.1-1 through 1.2-4
3. Figures 1.1-1 through 1.2-24

Enclosure 4: Non-LOCA Transients

1. Impact of RSG Installation on Non-Loss of Coolant Accident Transients
2. Tables 1.0-1 through 1.7-2
3. Figures 1.0.2-1 through 1.7-5

BACKGROUND

Over years of operation the original steam generators (OSGs) at ANO-2 have degraded due to various corrosion-related phenomena. Several of the tubes within the OSGs have consequently been removed from service in order to ensure a reliable primary-to-secondary boundary, thereby establishing prolonged protection of the health and safety of the public. Due to this degradation, several operating parameters have been adjusted to assure continued safe operation considering the reduced heat transfer area and Reactor Coolant System (RCS) volume due to tube plugging. The combined effect has been an overall degradation of the efficiency of the unit. To regain this efficiency and restore the primary-to-secondary boundary within the steam generators, Entergy Operations, Inc. has initiated efforts to purchase and install replacement steam generators (RSGs) during the upcoming refueling outage 2R14, currently scheduled to begin September 15, 2000.

The RSGs are a Westinghouse design. The OSGs were designed by Combustion Engineering. The new design has provided several enhancements to operational efficiencies that will be discussed in detail throughout this submittal. Examples of the differences are:

1. Increased number of tubes above the original number (prior to repair) of the OSGs
2. Increased primary-side volume
3. Increased secondary-side volume

The heat transfer areas have increased, along with increased primary-side flowrates. This results in a higher secondary-side operating pressure. The RSGs will, in fact, provide for greater efficiencies than achievable with the OSGs. Therefore, ANO-2 has performed evaluations to support the realization of these efficiencies following the RSG installation and will request approval for a power uprate from the 2815 MWt current value to a value of 3026 MWt following refueling outage 2R15 (currently scheduled for the spring of 2002).

Because of the differences in design between the OSGs and the RSGs discussed above and those differences that are discussed in detail in the following sections, evaluations were performed to assess the impact of the RSGs on both LOCA and non-LOCA events. Analyses were performed as an aggregate effort by Westinghouse, Combustion Engineering, and ANO Engineering personnel. The resultant analyses have indicated that several changes to the ANO-2 Technical Specifications (TSs) and the ANO-2 Safety Analysis Report (SAR) are required. Many of the changes are associated with automatic setpoints. Therefore, a brief description of how these setpoints interrelate follows.

The Plant Protective System (PPS) at ANO-2 is divided into two major subsystems: the Reactor Protective System (RPS) and the Engineered Safety Features Actuation System (ESFAS). The RPS functions to trip the reactor at pre-determined parameter values in order to ensure the reactor is placed in a subcritical state prior to any TS Safety Limit being exceeded. The RPS accomplishes this task by removing power from Control Element Assembly (CEA) magnetic coils, allowing gravity insertion of control rods into the reactor

core. The ESFAS acts to mitigate events that may threaten any of several Safety Functions designed to protect the core during and following shutdown, including the mitigation of any resultant offsite radiological exposure. The ESFAS accomplishes this task by isolating key radioactive boundaries and by initiating backup systems such as safety injection systems in order to maintain the reactor core in a subcooled state. As will be discussed in the following section, the installation and subsequent operation of the RSGs will impact several transient analyses and, therefore, result in several changes to both RPS and ESFAS setpoints. The PPS changes, along with proposed changes of other RSG-related submittals, will help ensure continued protection of the reactor core and the health and safety of the public during future RSG operation.

The aforementioned analyses and evaluations have additionally indicated a change in offsite radiological dose consequences to members of the public at both the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ). Although the total exposure at both locations remains well below regulatory limits, the projected exposures have increased slightly. This is conservatively considered an increase in dose consequences and, therefore, is an Unreviewed Safety Question (USQ) in accordance with 10 CFR 50.59(a)(2). Additionally, a change has been made to the methodology used to determine the resultant dose rates and exposures at the EAB and LPZ. The impact of the RSGs and the impact of the new methodology will be discussed in detail in the following section. These impacts have resulted in a change to Chapter 15, "Accident Analysis" of the ANO-2 SAR. Enclosure 2 contains the affected SAR pages that have been revised as a result of these impacts.

DISCUSSION OF CHANGE

In order to protect the health and safety of plant personnel and the public following installation of the replacement steam generators (RSGs), a review of the various accident analyses was necessary. Chapter 15 of the ANO-2 SAR considers the various accident scenarios that must be addressed when performing plant modifications. A listing of these scenarios may be found in Table 1.0-1 of Enclosure 4 of this submittal. The table illustrates how each accident event was evaluated in relation to installation and operation of the RSGs. Enclosure 4 contains information discussing the methods used in deciding whether or not the SAR events were reanalyzed, not reanalyzed, evaluated, or found to be not applicable.

As discussed previously, analyses were performed assuming operation with the RSGs in service. The following analyses are divided into two major subcategories: LOCA events and non-LOCA events. In the non-LOCA events that were reanalyzed, a power uprate of 7.5% was conservatively assumed, except for the Feedwater Line Break (FWLB) analysis. The FWLB analysis and the LOCA analyses were performed at the current power rating of 2815MWt. Along with the differences discussed previously when comparing the OSGs and the RSGs, the analyses also include planned improvements to the Main Turbine that provide greater excess steam flow than currently achievable. In addition, credit was taken for the internal flow-limiting outlet nozzle of the RSGs that acts to reduce the effective steam piping area to less than 2 ft^2 and the secondary mass differences that result from different level tap locations when compared to the OSGs. The two major analyses performed are discussed

below, followed by detailed discussion of each proposed TS change. In each analysis, approved codes and programs were used to determine the impact of operation with the RSGs. A listing of the computer programs, codes, and other basis documents may be found in the attached reference listings (Enclosures 3 and 4).

LOCA Analysis

An Emergency Core Cooling System (ECCS) performance analysis was completed for LOCA events in accordance with 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors." A detailed review of this analysis may be found in Enclosure 3 of this submittal. Results of the analysis ensure the peak clad temperature remains ≤2200° F, maximum clad oxidation remains ≤17%, maximum core-wide oxidation remains ≤1.0%, and that a coolable geometry is maintained during both large and small break LOCA events.

The most limiting large break LOCA identified in the SAR is the 0.6 Double-Ended Guillotine break at the reactor coolant pump (RCP) discharge, which is addressed in the Enclosure 3 analysis. A limited spectrum of the small break LOCA classes was evaluated. The most limiting was determined to be the 0.04 ft^2 break at the RCP discharge. Analyses also addressed the worst-case single failures and the availability, or unavailability, of offsite power sources. The ECCS performance analysis assumed an initial core power of 2900 MWt (2815 MWt + 3% uncertainty) and utilized RPS and ESFAS setpoints and analytical values that were at, or conservative to, the proposed TS settings mentioned previously in this submittal. Power uprate considerations were not included in the analysis.

The most limiting single failure of the ECCS in the large break LOCA analysis is *no* failure to the ECCS. No failure is the worst case condition because the amount of safety injection that spills into the containment is maximized. This acts to minimize containment pressure, in turn, minimizing the rate at which the core is reflooded. The *no* failure to the ECCS finding is consistent with the current large break LOCA analysis documented in the ANO-2 SAR.

Both the large break and small break LOCA analysis have been performed considering a low pressurizer pressure setpoint of 1400 psia. During a postulated large break LOCA, the rate of depressurization and voiding in the core is such that credit for a low pressurizer pressure trip setpoint has minimal impact on the analysis results. Conservative modeling assumptions with respect to ECCS spillage and safety injection tank (SIT) flow to the core prior to high pressure safety injection (HPSI) and low pressure safety injection (LPSI) flow minimize the impact of a low pressurizer pressure SIAS setpoint of 1400 psia. The 1400 psia value is conservative to that of the aforementioned proposed TS setpoints for the Low Pressurizer Pressure Trip, the Safety Injection Actuation Signal, and the Containment Cooling Actuation Signal.

The result of the ECCS performance analysis indicated that the necessary core parameters remained within the acceptance criteria discussed above. Therefore, based on the analysis results, installation and operation of the RSGs is acceptable.

Non-LOCA Analysis

The analyses performed concerning non-LOCA events (Enclosure 4) included those necessary to ensure that acceptance criteria would be met while operating the RSGs and, in most cases, with a 7.5% power uprate to 3026 MWt. Examples of non-LOCA events examined include overcooling events, loss-of-load events, CEA events, component misoperation or failure, etc.

Where RPS/ESFAS setpoint changes were required, those setpoints and analytical values proposed in this submittal were utilized, or more conservative values were assumed. The Variable Overpower Trip (VOPT) and the Asymmetric Steam Generator Trip (ASGT) of the Core Protection Calculators (CPCs) were also credited as effective protection against some accident events. Assumptions not previously mentioned, but that were employed in this analysis, include a more rapid flow coastdown period, modified response times including those of RPS/ESFAS functions, up to 10% tube plugging in each RSG when plugging made the results less favorable, and a more negative MTC. In addition, instrument uncertainties on PPS setpoints were inserted for harsh, abnormal, and normal environments, where applicable (Enclosure 4, Section 1.0.1). Bounding core physics data for MTC, Fuel Temperature Coefficient (FTC), the delayed neutron fraction, the effective neutron lifetime, and CEA worth were also utilized in the analyses.

As in the ECCS performance analysis, acceptance criteria were established for which the non-LOCA analyses would be bounding. Many of the criteria revolve around limits that ensure that the Specified Acceptable Fuel Design Limits (SAFDLs) would be maintained. For example, the minimum departure-from-nucleate-boiling ratio (DNBR) value obtained had to be greater than the DNB SAFDL. Additionally, peak linear heat rates (LHR), fuel centerline (C_L) melt temperatures, and clad damage/molten enthalpies were required to be maintained within specified limits. Criteria not directly related to fuel integrity include a reactor coolant system (RCS) pressure $\leq$2750 psia, a secondary system pressure $\leq$1210 psia, and no loss of the secondary heat sink. Projected doses at the exclusion area boundary (EAB) and low population zone (LPZ) must also remain within 10 CFR 100 limits.

The results of the non-LOCA analyses indicate that operation with the RSGs in service is within the current acceptance criteria. Additionally, the present High Pressurizer Pressure RPS setpoint was found to be acceptable, as were the proposed changes to the Low Pressurizer Pressure RPS/ESFAS setpoints, the Low Steam Generator Level RPS/ESFAS setpoints, the Low Steam Generator Pressure RPS/ESFAS setpoints, the High Linear Power RPS setpoints during inoperable MSSV operation, and the increase in the RCS flow limit. Some analytical values were also conservatively changed and found acceptable as a result of this analysis. Therefore, Cycle 15 operation with the RSGs in service is acceptable for all non-LOCA event analyses.

SGTR

The analysis for steam generator tube ruptures (SGTR) was not reanalyzed. Several inherent design differences of the RSGs, when compared with the OSGs, result in projected leak rates during SGTR events having decreased. The smaller diameter U-tubes of the RSGs result in less flow per tube (directly proportional to the square of the diameter). This alone provides a 13% reduction in U-tube leak rates. The higher secondary pressures resulting from the increased heat transfer area of the RSGs result in a reduction in the pressure differential between the primary and secondary systems during power operations. This likewise results in a reduction in U-tube leak rates (leak flow is proportional to the square root of the differential pressure). Additionally, increased U-tube flow resistance results in a 5% further reduction in U-tube leak rates. In summary, events involving U-tube failures are less significant for the RSGs than that of the OSGs and, therefore, the current analysis regarding SGTR events is bounding.

Loss of Primary Flow Events

The analysis associated with the loss of RCS flow resulted in a slight increase in the required thermal margin. However, in order to aid in offsetting the increased required thermal margin, the minimum thermal margin reserved by the Core Operating Limits Supervisory System (COLSS) and the DNBR Limit Plot (used when COLSS is out-of-service and maintained in the Core Operating Limits Report (COLR)) will be updated, if necessary, for Cycle 15.

Future Core Reload

For Major Secondary System Pipe Breaks, with or without a concurrent loss of AC power (Enclosure 4, Section 1.5.3), a sensitivity study was performed in addition to the analysis. The purpose of this study was to support future core reload efforts in regard to overcooling events with RSGs in service and an elevated rated thermal power of 3026 MWt with respect to required CEA worth at the time of trip. The acceptance criteria required a CEA worth at trip, given the aforementioned assumptions, that would maintain the minimum MacBeth DNBR $\geq$ 1.30 and a maximum LHR $\leq$21 KW/ft. The result of this study indicated that, for future core reloads, an incremental CEA worth at trip of 0.09% $\Delta\rho$ can be credited in future reload efforts. This information is provided as a convenience and is not required to support the proposed TS changes of this submittal.

Changes to Technical Specifications

Low Pressurizer Pressure Setpoint

The Low Pressurizer Pressure RPS and ESFAS setpoints were reduced from $\geq$ 1717.4 psia to $\geq$ 1675 psia, with the allowable values reduced from $\geq$ 1686.3 psia to $\geq$ 1643.9 psia. This setpoint change was supported by the use of a 1400 psia value in the aforementioned LOCA analysis. As mentioned previously, the SGTR event was not reanalyzed. This is significant in

that the current analysis utilizes a value of 1600 psia for the low RCS pressure Safety Injection Actuation Signal (SIAS). However, the proposed TS values above remain acceptable given either analysis value. The reduction in setpoint is necessary due to the larger RCS mass of the RSGs, resulting in increased shrink phenomena and reduced RCS pressures following a reactor trip. This setpoint is projected to be sufficiently reduced to prevent unnecessary ESFAS actuations following normal plant transients, and sufficiently above those values used in both the current analysis and the analysis performed in support of the RSGs and power uprate.

Low Steam Generator Pressure Setpoint

The Low Steam Generator Pressure RPS and ESFAS setpoints have been restored from ≥ 712 psia to ≥ 751 psia, with the allowable values increased from ≥ 699.6 psia to ≥ 738.6 psia. This setpoint change was supported by the use of conservative analysis values. The 751 psia value is the same as the original TS value prior to significant degradation of the OSGs. The increase in setpoint is a result of increased secondary operating pressures caused by the increased heat transfer areas of the RSGs. This setpoint is projected to be sufficiently below normal operating pressure to prevent unnecessary ESFAS actuations following normal plant transients, and sufficiently above those values used in both the current analysis and the analysis performed in support of the RSGs and power uprate.

Low Steam Generator Level Setpoint

The Low Steam Generator Level RPS and ESFAS setpoints were reduced from ≥ 23% to ≥ 22.2%, with the allowable values reduced from ≥ 22.111% to ≥ 21.5%. This setpoint change was supported by the use of conservative analytical values in the aforementioned analysis. Although the analytical values increased in some cases, the resulting RPS/ESFAS setpoint was reduced due to considerations of instrument uncertainty under harsh, abnormal, and normal conditions. In the RSGs, the normal water level is shifted to the region above the lower deck plate of the moisture removal area where the pool has a larger area to accommodate shrink and swell. The locations of the narrow range level instrument taps have also changed to elevations that provide a larger narrow range span for level control. The RSG narrow level span is approximately 40 inches greater than that of the OSGs. In addition, the normal operating level of 70% narrow range level is 436 inches above the top of the tubesheet. Given the OSGs and the current low level setpoint of ≥ 23%, actuation of the Emergency Feedwater (EFW) System commonly occurs upon reactor trips from full power. The reduced setpoint, along with the physical characteristics described above, is projected to be sufficient to help prevent these unnecessary ESFAS actuations following normal plant transients, and sufficiently above those values used in the analysis performed in support of the RSGs and power uprate. Therefore, an added benefit of reduced unnecessary starts of EFW components is gained by the installation of the RSGs and subsequent reduction in the Low Steam Generator Level ESFAS setpoint.

In addition, Note (3) of Table 3.3-4 is revised to clarify that the instrument associated with the Low Steam Generator Level setpoint requirements is the narrow range instrument. This clarification is necessary since the RSGs possess both wide range and narrow range instrumentation taps.

RCS Flow Limit

The RCS Flow Rate Limit has been restored from 108.4 x 10^6 lbm/hr to the original TS value of 120.4 x 10^6 lbm/hr. This change was supported by the use of conservative values, generally 98% of the flow limit, in the LOCA and non-LOCA analyses presented in Enclosures 3 and 4. The proposed value is the same as the original TS value that was analyzed as acceptable prior to significant degradation of the OSGs. The RCS Flow Rate Limit was reduced in ANO-2 TS Amendment 190. The increase is a result of the increased flow allowed by the RSGs compared to the increased flow resistance in the OSGs as a result of tube plugging.

High Linear Power Trip Setpoint With MSSVs Inoperable and Associated Bases

Changes not directly related to the RSGs are proposed for Specification 3.7.1.1 (MSSVs). Action (a) is revised to be applicable only for Modes 1 and 2 operations and to require a power reduction to less than the applicable Linear Power Level – High power percentage in accordance with Table 3.7-1 within 4 hours and then allow an additional 8 hours to reduce the Linear Power Level – High setpoint as required by Table 3.7-1. The 4-hour limit provides a reasonable period to reduce power level and is based on the low probability of an event that would require the use of MSSVs during this period. An additional 8 hours is allowed to reduce the Linear Power Level – High setpoints in recognition of the difficulty, based on operating experience, of resetting all channels of this trip function within a period of 4 hours. In addition, the probability of an event occurring within this time period that would be mitigated by this setpoint is low. The shutdown to Cold Shutdown statement of Action (a) is also changed to require shutdown to at least a Hot Shutdown condition. This change is justified due to the applicability of this specification being limited to Modes 1, 2, and 3 only. Therefore, upon entering Mode 4 (Hot Shutdown), the requirements and actions of this specification no longer apply. A 12-hour period is provided to reach Mode 4 from Mode 3 conditions. The above revisions are consistent with the current revision of the Revised Standard Technical Specifications (RSTS).

Action (b) of Specification 3.7.1.1 is changed to eliminate the applicability to Modes 1 and 2 and address appropriate actions for Mode 3 only since operation with less than two reactor coolant loops in Modes 1 and 2 is not allowed. In Mode 3, the reduction of Linear Power Level – High Trip setpoints would not add protection to a steam generator overpressurization event. Therefore, the requirements for reducing these setpoints have been deleted from Action (b). The ASME code, which requires two MSSVs to be operable on each steam generator during Mode 3 conditions regardless of the number of operating RCS loops, is incorporated. This is more restrictive than the current requirement of maintaining two MSSVs operable on the non-operating steam generator only. As in Action (a), the unit must be placed in at least a Hot Shutdown condition within 12 hours if at least two MSSVs are not operable on each steam generator.

The loss of condenser vacuum (LOCV) analysis provided in Enclosure 4 determined that a reduction in the High Linear Power Trip setpoint, above that of the current TS requirement, is appropriate when MSSVs are inoperable. As a result, the setpoint has been reduced from 67.7% to 43% of rated thermal power in cases where up to two MSSVs are inoperable on at least one steam header. For cases where up to three MSSVs are inoperable on an individual steam generator, the setpoint has been reduced from the current value of 36% to a value of 25% of rated thermal power. Because the reductions would not readily support performing testing of MSSVs during power operation without resulting in a significant decrease in rated thermal power below the proposed setpoints, a second methodology has been employed that may be used in cases where no greater than one MSSV per steam header is inoperable. Therefore, TS Table 3.7-1 refers the user to a new TS Figure 3.7-1 (replaces existing TS Table 3.7-2) during conditions where not more than one MSSV is inoperable on each steam header.

The addition of Figure 3.7-1 provides a graph of MTC versus the setpoint for the Linear Power Level – High Trip. The figure provides guidance for configurations with one MSSV inoperable up to a total of one MSSV per steam header being inoperable. In addition, a MTC versus EFPD correlation (Figure 1.0.2-1 of Enclosure 4) will be developed. This correlation will be incorporated into operating procedures. The user may obtain the current MTC value based on EFPD (core life) from the appropriate procedure, apply the MTC value to the proposed TS Figure 3.7-1, and acquire a High Linear Power Trip setpoint. The application of this new figure provides for a High Linear Power Trip setpoint for conditions where not more than one MSSV is inoperable on each steam header to support testing of the MSSVs without a significant decrease in plant power.

The setpoint reductions during conditions of two or more MSSVs being inoperable on each steam header are conservative with respect to the analysis performed in support of this submittal. Likewise, the application of MTC versus rated thermal power Figure 3.7-1 has been found acceptable for conditions where not more than one MSSV is inoperable per steam header. Therefore, the proposed changes associated with the High Linear Power Trip setpoints relating to cases where MSSVs are inoperable are acceptable.

Bases 3/4.7.1.1 defines the High Linear Power Trip setpoint based on the more conservative of two methods. The first method is a simplified calculation provided in the bases dependant upon the reduction in relieving capacity. In the second method the Loss of Condenser Vacuum (LOCV) event is used. The first method does not consider the transient and dynamic effects that are present during anticipated operational occurrences. The proposed change will eliminate the linear power reduction relationship listed in the Bases (the first method) and state that the acceptability with MSSVs inoperable will be determined by the initial power level assumed in the LOCV event. This change in bases is consistent with a similar change approved for Waterford 3 Steam Electric Station in License Amendment 142, June 26, 1997. The inadequacy of this first method is discussed in NRC Information Notice 94-60, Potential Overpressurization of Main Steam System. In Attachment I to the information notice, Westinghouse states that the linear relationship utilized in the Bases (similar to ABB-CE

plants) is a non-conservative assumption. Recommendation 2 of the attachment states that the issue may be appropriately addressed by analyzing the limiting accident at the power level that is stated in the proposed ANO-2 TS Table 3.7-1 with the corresponding number of MSSVs inoperable.

Additionally, the reference to 1100 psia in the 1st paragraph is deleted and the 3rd sentence of the 2nd paragraph is revised for clarity. The reference to 1100 psia could have caused confusion since the RSG is rated for 1100 psig, while the remainder of the secondary main steam components is rated for 1100 psia. The last paragraph is added, providing the bases for the aforementioned 12-hour completion time for resetting Linear Power Level – High Trip setpoints in accordance with Table 3.7-1.

Safety Analysis Report Revisions

As discussed previously, analyses performed in support of the RSGs and power uprate result in a slight increase in radiological doses at the EAB and LPZ for members of the public. The increases are primarily due to a new methodology employed in calculating offsite doses. Since the new methodology is inconsistent with that used in the current analysis, revisions to Chapter 15 of the ANO-2 SAR are warranted. The new methodology uses more conservative values when assessing offsite releases. The revised SAR pages and associated markup copies are included in Enclosure 2 of this submittal.

The MSLB and FWLB analyses were found to be bounding for offsite dose considerations. The new methodology utilized, in many cases, more conservative values than those of the current analysis. For example, 0.1 μCi/g dose equivalent (DEQ) I-131 of secondary activity and 1.0 μCi/g DEQ I-131 of primary activity was assumed with a steam generator tube leakage of 0.5 gpm per steam generator. For the intact steam generator, an iodine partitioning factor of 100 was assumed versus a factor of 400 utilized in the current analysis. The analysis considered power uprate to 3087 MWt (102% of 3026 MWt) and assumed no operator action to commence a cooldown using the intact steam generator for 30 minutes.

The results indicated both whole body and thyroid doses at the EAB and LPZ to be within 10 CFR 100 limits. Anticipated Operational Occurrences (AOOs) were not reanalyzed since the MSLB and FWLB analysis adequately bound the assumptions utilized in AOO analysis. Seized Rotor resultant doses were derived for up to 14% failed fuel conditions and found to be within 10 CFR 100 limits. The methodology employed and the analytical results have been incorporated in the revisions to the ANO-2 SAR. Based on the above analyses and methodology, the revisions to the ANO-2 SAR are considered acceptable. In addition, operation with the RSGs in service beyond 2R14 is acceptable based on the projected doses at the EAB and LPZ remaining within 10 CFR 100 limits, as analyzed in support of this submittal.

Summary

The analyses performed in support of this submittal have indicated that operation with RSGs in service and, for selected analyses, the subsequent power uprate are acceptable. Limits surrounding the core SAFDLs, TS Safety Limits, and mitigating Safety Functions have been maintained throughout the various analyses designed to justify RSG installation and, in specific cases, power uprate. Additionally, the increase in offsite dose has been found acceptable since dose results remain within the 10 CFR 100 limits. Therefore, the resultant USQ has been adequately addressed. In addition, installation of the RSGs will restore the integrity of the primary-to-secondary boundary to a superior state. Based on the above discussions and attached analyses, installation and operation of the RSGs is acceptable.

DETERMINATION OF NO SIGNIFICANT HAZARDS CONSIDERATION

Entergy Operations, Inc. is proposing that the Arkansas Nuclear One, Unit 2 (ANO-2) Operating License be amended to revise affected Technical Specification (TS) limits associated with the steam generator replacement project. The new limits act to capture the design efficiencies gained by the installation of replacement steam generators (RSGs) and ensure safety margins remain acceptable during subsequent operations with the RSGs in service. Several differences are inherent between the RSGs and the original steam generators (OSGs) that have impacted several Reactor Protective System (RPS) and Emergency Safety Features Actuation System (ESFAS) setpoints. The RSGs have an increased primary and secondary volume and lower resistance to RCS flow. The increase in the primary volume increases the RCS shrink phenomena that results from a reactor trip. Additionally, the increased heat transfer areas of the RSGs have raised the secondary operating pressure. The aforementioned differences have resulted in the proposed revision of the following TSs.

- The Low Steam Generator Pressure RPS and ESFAS setpoints have increased from ≥ 712 psia to ≥ 751 psia, with the allowable values increased from ≥ 699.6 psia to ≥ 738.6 psia.

- The Low Steam Generator Level RPS and ESFAS setpoints have decreased from ≥ 23% to ≥ 22.2%, with the allowable values reduced from ≥ 22.111% to ≥ 21.5%. Note (3), which is associated with these level setpoints, is clarified to refer to the narrow range instrumentation.

- The Low Pressurizer Pressure RPS and ESFAS setpoints have decreased from ≥ 1717.4 psia to ≥ 1675 psia, with the allowable values reduced from ≥ 1686.3 psia to ≥ 1643.9 psia.

- The RCS Flow Rate Limit has been restored from 108.4 x 10^6 lbm/hr to its original 120.4 x 10^6 lbm/hr.

- Action (a) of Specification 3.7.1.1 is revised to allow up to 12 hours to reduce the High Linear Power Level – High Trip setpoint in accordance with Table 3.7-1 when one or more MSSVs are inoperable.

- The High Linear Power Trip setpoint has been reduced from 67.7% to 43% of rated thermal power in cases where up to two Main Steam Safety Valves (MSSVs) are inoperable on a steam header. For cases where up to three MSSVs are inoperable on a steam header, the setpoint has been reduced from the current value of 36% to a value of 25% of rated thermal power. New TS Figure 3.7-1 (replaces existing TS Table 3.7-2) has been added to determine the High Linear Power Trip setpoint during conditions where not more than one MSSV is inoperable per steam header.

- The Bases to the High Linear Power Trip setpoint reductions during periods when MSSV(s) are inoperable is changed to eliminate the linear power reduction relationship (the first method) and state that the acceptability with MSSVs inoperable will be determined by the initial power level assumed in the Loss of Condenser Vacuum event.

In addition, the reanalysis of several Design Basis Events (DBEs) and a change in the methodology employed in determining offsite release values have resulted in a slight increase in the radiological dose consequences at the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ). However, the resultant dose increases are very small and remain within acceptance criteria. The results of the radiological analysis, along with the methodology employed in determining the offsite dose consequences, have required a revision to the current ANO-2 Safety Analysis Report (SAR).

An evaluation of the proposed change has been performed in accordance with 10CFR50.91(a)(1) regarding no significant hazards considerations using the standards in 10CFR50.92(c). A discussion of these standards as they relate to this amendment request follows:

Criterion 1 - Does Not Involve a Significant Increase in the Probability or Consequences of an Accident Previously Evaluated.

The proposed changes to the ANO-2 TSs are analytically based which change setpoints and procedural limits. No physical modifications are required as a result of the proposed changes. The RPS/ESFAS setpoint changes provide functionally equivalent protection with the RSGs as the previous setpoint values provided with the OSGs. Proposed changes in regard to RCS flow rate and High Linear Power Trip setpoints associated with conditions where MSSVs are inoperable represent appropriate restrictions that have resulted from the various analyses performed in support of RSG installation. An Emergency Core Cooling System (ECCS) performance analysis was performed to demonstrate conformance to 10 CFR 50.46 for operation with RSGs. For the large break Loss of Coolant Accident (LOCA), the most limiting single failure of the ECCS. The small break LOCA analysis was

reanalyzed using the existing Supplement 2 Model (S2M) of the ABB CENP small break LOCA evaluation model. The analysis was performed for 0.03 ft^2, 0.04 ft^2, and 0.05 ft^2 sizes in the reactor coolant pump (RCP) discharge leg. The results of both analyses demonstrate continued conformance to the ECCS acceptance criteria of 10 CFR 50.46. Non-LOCA analyses intended to confirm the Chapter 15 events in the ANO-2 SAR were also performed. The analyses were performed considering the proposed Safety Limits and the Limiting Safety Settings of the TSs and were confirmed to be bounding for the affected safety analyses. The results of the non-LOCA analyses indicate that operation with the RSGs in service is acceptable. As a result of the analyses and evaluations performed in support of the RSGs, the ANO specific safety parameters and regulatory limits are protected. Therefore, the proposed TS changes will not significantly increase the probability of an accident previously analyzed.

Loss of Coolant Accidents (LOCAs) and non-LOCA safety analyses supporting the proposed changes have been performed and have demonstrated conformance with all applicable Licensing Basis acceptance criteria. Although calculated radiological doses using newer, more conservative methods increase for some non-LOCA events (requiring a revision to Chapter 15 of the SAR), the results are within the acceptance criteria of 10 CFR 100. Therefore, the proposed changes do not involve a significant increase in the consequences of an accident previously evaluated.

Therefore, the proposed changes do <u>not</u> involve a significant increase in the probability or consequences of any accident previously evaluated.

Criterion 2 - Does Not Create the Possibility of a New or Different Kind of Accident from any Previously Evaluated.

The proposed changes to the ANO-2 TSs are analytically based and require changing plant setpoints and procedural limits. No physical modifications are required as a result of the proposed changes. The RPS/ESFAS setpoint changes provide functionally equivalent protection with the RSGs as the previous setpoint values provided with the OSGs. Proposed changes in regard to RCS flow rate and High Linear Power Trip setpoints associated with conditions where MSSVs are inoperable represent appropriate restrictions that have resulted from the various analyses performed in support of RSG installation. The additional 8 hours provided for reducing the High Linear Power Level trip setpoints is acceptable due to the low probability of an event occurring within this period, based on operating experience which indicates such a time period is reasonable to complete the changes, and to provide consistency with the RSTS. Therefore, the proposed TS changes will not create the possibility of a new or different kind of accident than previously analyzed.

A review of both LOCA and non-LOCA events was performed which confirms that existing licensing basis methodologies have been considered and that a new accident event has not been created.

Therefore, this change does not create the possibility of a new or different kind of accident from any previously evaluated.

Criterion 3 - Does Not Involve a Significant Reduction in the Margin of Safety.

LOCA and non-LOCA safety analyses supporting the proposed changes have been performed and have demonstrated conformance within applicable acceptance criteria. With the increased size of the RSGs and the change in design characteristics, the bases for the setpoints in the ANO-2 TSs are affected. However, based on the new analyses and evaluations conducted in support of this license amendment, the new TS setpoints provide adequate margin to protect established safety and regulatory limits. Although calculated offsite radiological doses increase slightly for some non-LOCA events documented in Chapter 15 of the ANO-2 SAR, the increases are not considered to be significant in that the results remain within the 10 CFR 100 acceptance criteria.

Therefore, this change does not involve a significant reduction in the margin of safety.

Therefore, based on the reasoning presented above and the previous discussion of the amendment request, Entergy Operations, Inc. has determined that the requested changes do not involve a significant hazards consideration.

ENVIRONMENTAL IMPACT EVALUATION

10 CFR 51.22(c) provides criteria for and identification of licensing and regulatory actions eligible for categorical exclusion from performing an environmental assessment. A proposed amendment to an operating license for a facility requires no environmental assessment if operation of the facility in accordance with the proposed amendment would not: (1) involve a significant hazards consideration, (2) result in a significant change in the types or significant increase in the amounts of any effluents that may be released off-site, or (3) result in a significant increase in individual or cumulative occupational radiation exposure. Entergy Operations, Inc. has reviewed this license amendment and has determined that it meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the proposed license amendment. The bases for this determination is as follows:

1. The proposed license amendment does not involve a significant hazards consideration as described previously in the evaluation.

2. As discussed in the significant hazards evaluation, this change does not result in a significant change or significant increase in the radiological doses for any Design Based Accident. The proposed license amendment does not result in a significant change in the types or a significant increase in the amounts of any effluents that may be released off-site.

3. The proposed license amendment does not result in a significant increase to the individual or cumulative occupational radiation exposure because this does not modify the method of operation of systems and components necessary to prevent a radioactive release.

ENCLOSURE 1

TO

2CAN119901

PROPOSED ANO-2 TECHNICAL SPECIFICATION CHANGES

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Linear Power Level - High		
a. Four Reactor Coolant Pumps Operating	≤110% of RATED THERMAL POWER	≤110.712% of RATED THERMAL POWER
3. Logarithmic Power Level - High (1)	≤0.75%	≤0.819%
4. Pressurizer Pressure - High	≤2362 psia	≤2370.887 psia
5. Pressurizer Pressure - Low	≥ 1675 psia (2)	≥ 1643.9 psia (2)
6. Containment Pressure - High	≤18.3 psia	≤18.490 psia
7. Steam Generator Pressure - Low	≥ 751 psia (3)	≥ 738.6 psia (3)
8. Steam Generator Level - Low	≥ 22.2% (4)	≥ 21.5% (4)

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~~Revised by NRC Letter dated May 17, 1999~~

Pressurizer Pressure-High

The Pressurizer Pressure-High trip, in conjunction with the pressurizer safety valves and main steam safety valves, provides reactor coolant system protection against overpressurization in the event of loss of load without reactor trip. This trip's setpoint is at ≤2370.887 psia which is below the nominal lift setting (2500 psia) of the pressurizer safety valves and its operation avoids the undesirable operation of the pressurizer safety valves.

Pressurizer Pressure-Low

The Pressurizer Pressure-Low trip is provided to trip the reactor and to assist the Engineered Safety Features System in the event of a Loss of Coolant Accident. This trip's setpoint may be manually decreased, to a minimum value of 100 psia, as pressurizer pressure is reduced during plant shutdowns, provided the margin between the pressurizer pressure and this trip's setpoint is maintained at ≤200 psi; this setpoint increases automatically as pressurizer pressure increases until the trip setpoint is reached.

Containment Pressure-High

The Containment Pressure-High trip provides assurance that a reactor trip is initiated concurrently with a safety injection. The setpoint for this trip is identical to the safety injection setpoint.

Steam Generator Pressure-Low

The Steam Generator Pressure-Low trip provides protection against an excessive rate of heat extraction from the steam generators and subsequent cooldown of the reactor coolant. The setpoint is sufficiently below the full load operating point so as not to interfere with normal operation, but still high enough to provide the required protection in the event of excessively high steam flow. This trip's setpoint may be manually decreased as steam generator pressure is reduced during plant shutdowns, provided the margin between the steam generator pressure and this trip's setpoint is maintained at ≤200 psi; this setpoint increases automatically as steam generator pressure increases until the trip setpoint is reached.

RCS FLOW RATE

LIMITING CONDITION FOR OPERATION

3.2.5 The actual Reactor Coolant System total flow rate shall be greater than or equal to 120.4×10^6 lbm/hr.

APPLICABILITY: MODE 1

ACTION:

With the actual Reactor Coolant System total flow rate determined to be less than the above limit, reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5 The actual Reactor Coolant System total flow rate shall be determined to be within its limit at least once per 12 hours.

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤18.3 psia	≤18.490 psia
c. Pressurizer Pressure - Low	≥ 1675 psia	≥ 1643.9 psia
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Containment Pressure - High-High	≤23.3 psia	≤23.490 psia
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Containment Pressure - High	≤18.3 psia	≤18.490 psia

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
4. MAIN STEAM AND FEEDWATER ISOLATION (MSIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	≥ 751 psia (2)	≥ 738.6 psia (2)
5. CONTAINMENT COOLING (CCAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Containment Pressure - High	≤18.3 psia	≤18.490 psia
c. Pressurizer Pressure - Low	≥ 1675 psia	≥ 1643.9 psia
6. RECIRCULATION (RAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Tank - Low	54,400 ± 2,370 gallons (equivalent to 6.0 ± 0.5% indicated level)	between 51,050 and 58,600 gallons (equivalent to between 5.111% and 6.889% indicated level)
7. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage	(4)	2300 ± 699 volts with a 0.64 ± 0.34 second time delay
b. 460 volt Emergency Bus Undervoltage	423 ± 2.0 volts with an 8.0 ± 0.5 second time delay	423 ± 4.0 volts with an 8.0 ± 0.8 second time delay

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (A&B) Level - Low	≥ 22.2% (3)	≥ 21.5% (3)
c. Steam Generator ΔP-High (SG-A > SG-B)	≤90 psi	≤99.344
d. Steam Generator ΔP-High (SG-B > SG-A)	≤90 psi	≤99.344
e Steam Generator (A&B) Pressure - Low	≥ 751 psia (2)	≥ 738.6 psia (2)

(1) Value may be decreased manually, to a minimum of ≥ 100 psia, during a planned reduction in pressurizer pressure, provided the margin between the pressurizer pressure and this value is maintained at ≤200 psi; the setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed before pressurizer pressure exceeds 500 psia.

(2) Value may be decreased manually during a planned reduction in steam generator pressure, provided the margin between the steam generator pressure and this value is maintained at ≤200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

(3) % of the distance between steam generator upper and lower narrow range level instrument nozzles.

(4) The trip value for this function is listed in the surveillance test procedures. The trip value will ensure that adequate protection is provided when all the applicable calibration tolerances, channel uncertainties, and time delays are taken into account.

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings as specified in Table 3.7-5.

APPLICABILITY: MODES 1, 2 and 3*

ACTION:

MODES 1 and 2

With one or more main steam line code safety valves inoperable, operation in MODES 1 and 2 may proceed provided that within 4 hours, power is reduced to less than or equal to the applicable percent of RATED THERMAL POWER as listed in Table 3.7-1 and within 12 hours, the Linear Power Level-High trip setpoint is reduced per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 12 hours.

MODE 3

With one or more main steam line code safety valves inoperable, operation in MODE 3 may proceed provided that at least 2 main steam line code safety valves are OPERABLE on each steam generator; otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.1 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*Except that during hydrostatic testing in Mode 3, eight of the main steam line code safety valves may be gagged and two (one on each header) may be reset for the duration of the test to allow the required pressure for the test to be attained. The Reactor Trip Breakers shall be open for the duration of the test.

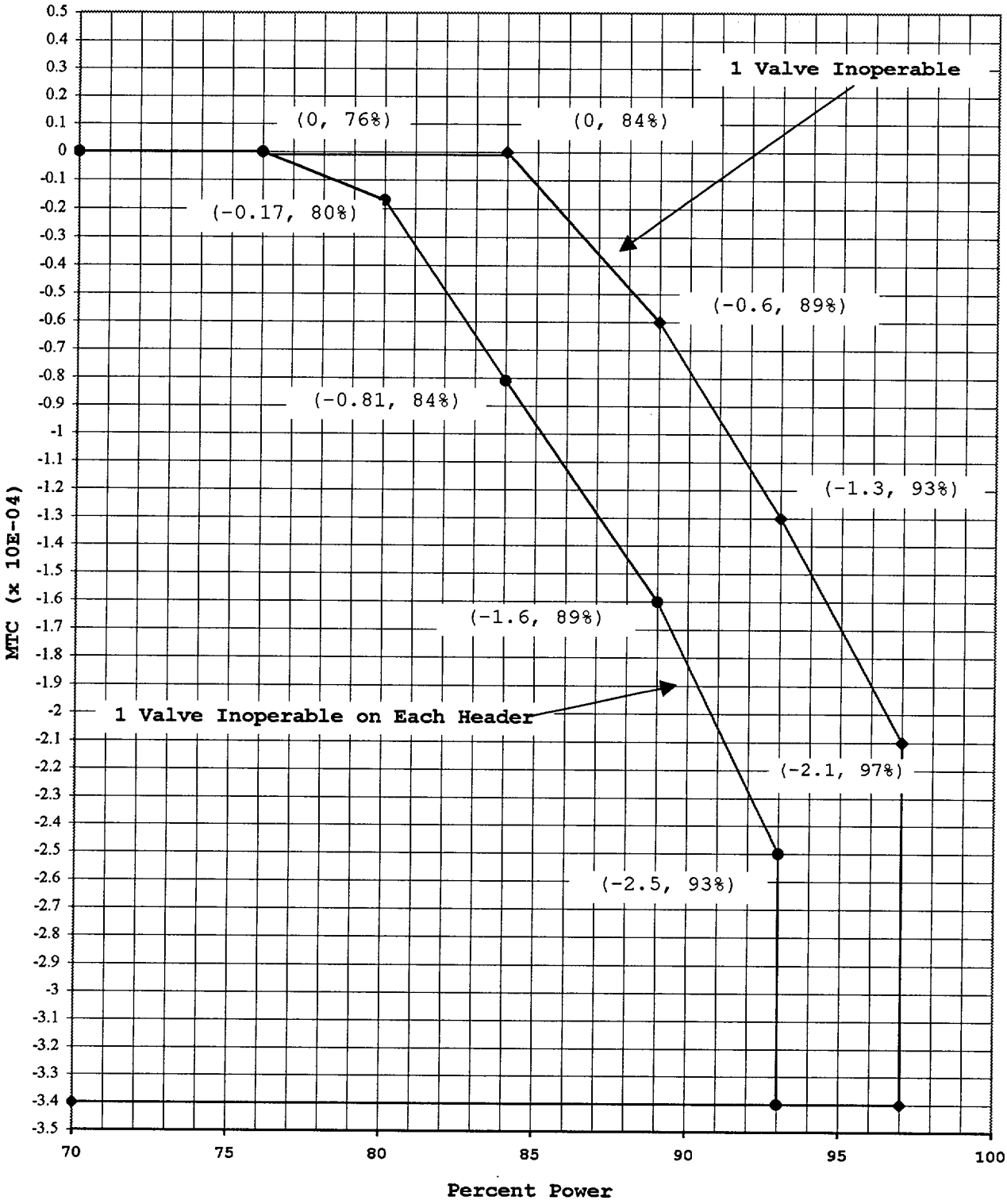
TABLE 3.7-1

MAXIMUM ALLOWABLE LINEAR POWER LEVEL AND HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

Number of Inoperable Safety Valves	Maximum Allowable Linear Power Level And High Trip Setpoint (Percent of RATED THERMAL POWER)
1 Valve Inoperable	84% (except as allowed by Figure 3.7-1)
1 Valve Inoperable on Each Header	76% (except as allowed by Figure 3.7-1)
Maximum of 2 Valves Inoperable on Each Header	43.0
Maximum of 3 Valves Inoperable on Each Header	25.0

FIGURE 3.7-1

MTC Versus Maximum High Linear Power Level And Trip Setpoint



3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% of its design pressure during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The "as-found" requirements are consistent with Section XI of the ASME Boiler and Pressure Vessel Code, 1986 Edition, and Addenda through 1987. The MSSV capacity exceeds the 102% RATED THERMAL POWER (100% + 2% for instrument error) steam flow with steam pressure at 110% of the secondary system design pressure. A minimum of 2 OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for removing decay heat.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in secondary system steam flow and THERMAL POWER required by the reduced reactor trip settings of the Power Level-High channels. The reactor trip setpoint reductions are derived by an analysis of a loss of condenser vacuum event initiated at the reduced power levels listed in Table 3.7-1 that shows peak steam generator pressures are maintained below 110% of design pressure.

To provide power level limits more amenable to MSSV testing, the LOCV analysis also determines the combination of allowable initial power levels and moderator temperature coefficients (MTC) that yield acceptable results for the single most limiting valve and one bank of valves inoperable. These power level/MTC combinations are the basis of Figure 3.7-1.

The 4-hour completion time for required Action (a) is a reasonable time period to reduce power level and is based on the low probability of an event occurring during this period that would require activation of the MSSVs. An additional 8 hours is allowed in Action (a) to reduce the setpoints in recognition of the difficulty of resetting all channels of this trip function within a period of 4 hours. The completion time of 12 hours for Action (a) is based on operating experience in resetting all channels of a protective function and on the low probability of the occurrence of a transient that would result in steam generator overpressure during this period.

MARKUP OF CURRENT ANO-2 TECHNICAL SPECIFICATIONS

(FOR INFO ONLY)

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Linear Power Level - High		
a. Four Reactor Coolant Pumps Operating	≤110% of RATED THERMAL POWER	≤110.712% of RATED THERMAL POWER
~~b. Three Reactor Coolant Pumps Operating~~	~~*~~	~~*~~
~~c. Two Reactor Coolant Pumps Operating - Same Loop~~	~~*~~	~~*~~
~~d. Two Reactor Coolant Pumps Operating - Opposite Loops~~	~~*~~	~~*~~
3. Logarithmic Power Level - High (1)	≤0.75%	≤0.819%
4. Pressurizer Pressure - High	≤2362 psia	≤2370.887 psia
5. Pressurizer Pressure - Low	≥ ~~1717.4~~1675 psia (2)	≥ ~~1686.3~~1643.9 psia (2)
6. Containment Pressure - High	≤18.3 psia	≤18.490 psia
7. Steam Generator Pressure - Low	≥ ~~712~~ 751 psia (3)	≥ ~~699.6~~738.6 psia (3)
8. Steam Generator Level - Low	≥ ~~23~~22.2% (4)	≥ ~~22.111~~21.5% (4)

~~* These values left blank pending NRC approval of safety analyses for operation with less than four reactor coolant pumps operating.~~

Pressurizer Pressure-High

The Pressurizer Pressure-High trip, in conjunction with the pressurizer safety valves and main steam safety valves, provides reactor coolant system protection against overpressurization in the event of loss of load without reactor trip. This trip's setpoint is at ≤2370.887 psia which is below the nominal lift setting (2500 psia) of the pressurizer safety valves and its operation avoids the undesirable operation of the pressurizer safety valves.

Pressurizer Pressure-Low

The Pressurizer Pressure-Low trip is provided to trip the reactor and to assist the Engineered Safety Features System in the event of a Loss of Coolant Accident. ~~During normal operation, this trip's setpoint is set at ≥1686.3 psia.~~ This trip's setpoint may be manually decreased, to a minimum value of 100 psia, as pressurizer pressure is reduced during plant shutdowns, provided the margin between the pressurizer pressure and this trip's setpoint is maintained at ≤200 psi; this setpoint increases automatically as pressurizer pressure increases until the trip setpoint is reached.

Containment Pressure-High

The Containment Pressure-High trip provides assurance that a reactor trip is initiated concurrently with a safety injection. The setpoint for this trip is identical to the safety injection setpoint.

Steam Generator Pressure-Low

The Steam Generator Pressure-Low trip provides protection against an excessive rate of heat extraction from the steam generators and subsequent cooldown of the reactor coolant. The setpoint is sufficiently below the full load operating point so as not to interfere with normal operation, but still high enough to provide the required protection in the event of excessively high steam flow. This trip's setpoint may be manually decreased as steam generator pressure is reduced during plant shutdowns, provided the margin between the steam generator pressure and this trip's setpoint is maintained at ≤200 psi; this setpoint increases automatically as steam generator pressure increases until the trip setpoint is reached.

RCS FLOW RATE

LIMITING CONDITION FOR OPERATION

3.2.5 The actual Reactor Coolant System total flow rate shall be greater than or equal to ~~108.4~~120.4 x 10^6 lbm/hr~~ (Note 1)~~.

APPLICABILITY: MODE 1

ACTION:

With the actual Reactor Coolant System total flow rate determined to be less than the above limit, reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5 The actual Reactor Coolant System total flow rate shall be determined to be within its limit at least once per 12 hours.

~~Note 1: The value of 120.4 x 10^6 lbm/hr has been reduced to 108.4 x 10^6 lbm/hr until the steam generators are replaced. After the steam generators are replaced, this value returns to 120.4 x 10^6 lbm/hr.~~

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤18.3 psia	≤18.490 psia
c. Pressurizer Pressure - Low	≥ ~~1717.4~~1675 psia	≥ ~~1686.3~~1643.9 psia
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Containment Pressure - High-High	≤23.3 psia	≤23.490 psia
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Containment Pressure - High	≤18.3 psia	≤18.490 psia

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
4. MAIN STEAM AND FEEDWATER ISOLATION (MSIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	≥ ~~712~~ 751 psia (2)	≥ ~~699.6~~738.6 psia (2)
5. CONTAINMENT COOLING (CCAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Containment Pressure - High	≤18.3 psia	≤18.490 psia
c. Pressurizer Pressure - Low	≥ ~~1717.4~~1675 psia	≥ ~~1686.3~~1643.9 psia
6. RECIRCULATION (RAS)		
a. Manual (Trip Buttons	Not Applicable	Not Applicable
b. Refueling Water Tank - Low	54,400 ± 2,370 gallons (equivalent to 6.0 ± 0.5% indicated level)	between 51,050 and 58,600 gallons (equivalent to between 5.111% and 6.889% indicated level)
7. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage	(4)	2300 ± 699 volts with a 0.64 ± 0.34 second time delay
b. 460 volt Emergency Bus Undervoltage	423 ± 2.0 volts with an 8.0 ± 0.5 second time delay	423 ± 4.0 volts with an 8.0 ± 0.8 second time delay

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (A&B) Level - Low	≥ ~~23~~22.2% (3)	≥ ~~22.111~~21.5% (3)
c. Steam Generator ΔP-High (SG-A > SG-B)	≤90 psi	≤99.344
d. Steam Generator ΔP-High (SG-B > SG-A)	≤90 psi	≤99.344
e Steam Generator (A&B) Pressure - Low	≥ ~~712~~ 751 psia (2)	≥ ~~699.6~~738.6 psia (2)

(1) Value may be decreased manually, to a minimum of ≥ 100 psia, during a planned reduction in pressurizer pressure, provided the margin between the pressurizer pressure and this value is maintained at ≤200 psi; the setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed before pressurizer pressure exceeds 500 psia.

(2) Value may be decreased manually during a planned reduction in steam generator pressure, provided the margin between the steam generator pressure and this value is maintained at ≤200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

(3) % of the distance between steam generator upper and lower narrow range level instrument nozzles.

(4) The trip value for this function is listed in the surveillance test procedures. The trip value will ensure that adequate protection is provided when all the applicable calibration tolerances, channel uncertainties, and time delays are taken into account.

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3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings as specified in Table 3.7-5.

APPLICABILITY: MODES 1, 2 and 3*

ACTION:

a. With ~~both reactor coolant loops and associated steam generators in operation and with~~ one or more main steam line code safety valves inoperable, operation in MODES 1~~,~~ and 2~~, and 3~~ may proceed provided that~~,~~ within 4 hours, power is reduced to less than or equal to the applicable percent of RATED THERMAL POWER as listed in Table 3.7-1 and within 12 hours~~, either the inoperable valve is restored to OPERABLE status or~~ the Linear Power Level - High trip setpoint is reduced per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in ~~COLD~~ HOT SHUTDOWN within the following ~~30~~ 12 hours.

b. With ~~one reactor coolant loop and associated steam generator in operation and with~~ one or more main steam line code safety valves ~~associated with the operating steam generator~~ inoperable, operation in MODE~~S~~ ~~1, 2 and~~ 3 may proceed provided that at least 2 main steam line code safety valves are OPERABLE on each steam generator; otherwise, be in at least HOT SHUTDOWN witin the next 12 hours.~~:~~

~~1. That at least 2 main steam line code safety valves on the non-operating steam generator are OPERABLE, and~~

~~2. That within 4 hours, either the inoperable valve is restored to OPERABLE status or the Linear Power Level-High trip setpoint is reduced per Table 3.7-2; otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.~~

SURVEILLANCE REQUIREMENTS

4.7.1.1 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*Except that during hydrostatic testing in Mode 3, eight of the main steam line code safety valves may be gagged and two (one on each header) may be reset for the duration of the test to allow the required pressure for the test to be attained. The Reactor Trip Breakers shall be open for the duration of the test.

TABLE 3.7-1

MAXIMUM ALLOWABLE LINEAR POWER LEVEL POWER AND -HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

~~Maximum~~ Number of Inoperable Safety Valves ~~on Any Operating Steam Generator~~	Maximum Allowable Linear Power Level- And High Trip Setpoint (Percent of RATED THERMAL POWER)
1 Valve Inoperable	~~91.0~~84% (except as allowed by Figure 3.7-1)
1 Valve Inoperable on Each Header	76% (except as allowed by Figure 3.7-1)
Maximum of 2 Valves Inoperable on Each Header~~2~~	~~67.7~~43.0
Maximum of 3 Valves Inoperable on Each Header~~3~~	~~36.0~~25.0

~~TABLE 3.7-2~~

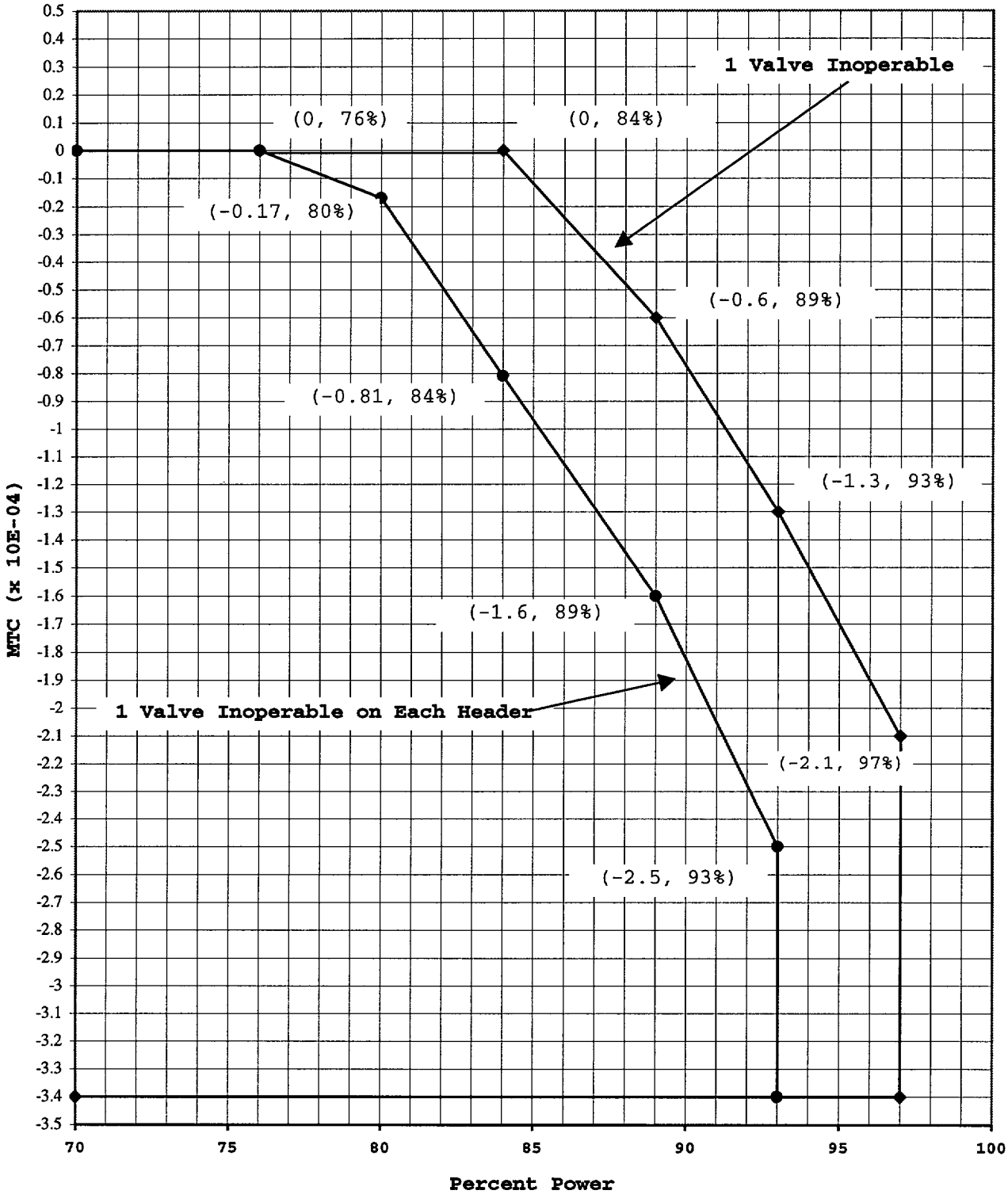
~~MAXIMUM ALLOWABLE LINEAR POWER LEVEL HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH ONE STEAM GENERATOR~~

~~Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator~~	~~Maximum Allowable Linear Power Level High Trip Setpoint (Percent of RATED THERMAL POWER)~~
~~1~~	~~*~~
~~2~~	~~*~~
~~3~~	~~*~~

~~*These values left blank pending NRC approval of safety analyses for operation with less than four reactor coolant pumps operating.~~

FIGURE 3.7-1

MTC Versus Maximum High Linear Power Level And Trip Setpoint



3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY ~~CYCLES~~VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% of its design pressure ~~of 1100 psia~~ during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The "as-found" requirements are consistent with Section XI of the ASME Boiler and Pressure Vessel Code, 1986 Edition, and Addenda through 1987. The MSSV ~~rated~~ capacity ~~passes~~ exceeds the ~~full steam flow at~~ 102% RATED THERMAL POWER (100% + 2% for instrument error) steam flow with ~~the valves fully open~~steam generator pressure at 110% of secondary system design presssure. A minimum of 2 OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for removing decay heat.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in secondary system steam flow and THERMAL POWER required by the reduced reactor trip settings of the Power Level-High channels. The reactor trip setpoint~~s are determined from the most conservative value obtained from two methods. The first method calculates setpoints based on the reduction in relieving capacity with the number of MSSVs inoperable and are derived as follows:~~reductions are derived by an analysis of a loss of condenser vacuum event initiated at the reduced power levels listed in Table 3.7-1 that shows peak steam generator pressures are maintained below 110% of design pressure.

~~$$SP = \frac{(X) - (Y)}{X} \times (Z\%)$$~~

~~where:~~

~~SP = Reduced reactor trip setpoint in percent of RATED THERMAL POWER~~

~~Z% = Total maximum safety valve relieving capacity of 102% power steam flow~~

~~X = Total relieving capacity of all safety valves per steam line in lbs/hour~~

~~Y = Total maximum relieving capacity of the inoperable safety valve(s) in lbs/hour. In each case, the valves with the greatest relieving capacity were assumed inoperable.~~

~~In the second method, the setpoint is determined from the Loss of Condenser Vacuum (LOCV) event. With + 3% MSSV tolerance, the LOCV event is analyzed with 1, 2, or 3 inoperable MSSVs on any steam generator, to determine the allowable initial power levels (and the trip setpoints) that yield acceptable results. For each of the inoperable MSSV conditions (1, 2, or 3 inoperable) in Table 3.7-1, the more conservative trip setpoint from the two analytical methods is selected.~~

To provide power level limits more amenable to MSSV testing, the LOCV analysis also determines the combination of allowable initial power levels and moderator temperature coefficients (MTC) that yield acceptable results for the single most limiting valve and one bank of valves inoperable. These power level/MTC combinations are the basis of Figure 3.7-1.

The 4-hour completion time for required Action (a) is a reasonable time period to reduce power level and is based on the low probability of an event occurring during this period that would require activation of the MSSVs. An additional 8 hours is allowed in Action (a) to reduce the setpoints in recognition of the difficulty of resetting all channels of this trip function within a period of 4 hours. The completion time of 12 hours for Action (a) is based on operating experience in resetting all channels of a protective function and on the low probability of the occurrence of a transient that would result in steam generator overpressure during this period.

ENCLOSURE 2

TO

2CAN119901

MARKUP OF THE CURRENT ANO-2 SAFETY ANALYSIS REPORT

(FOR INFO ONLY)

The main steam system radiological concentrations under full power operating conditions are given in Table 15.1.0-2.

15.1.0.5.2 Dose Model Assumptions

In order to determine the doses resulting from plant accidents, a five percentile criterion is used to determine atmospheric dispersion characteristics. The criterion is selected as being conservative on the basis that it represents unusually severe conditions. The actual conditions may be more severe only five percent of the time and less severe the remaining 95 percent of the time.

The following assumptions are basic to both the model for the whole body dose due to immersion in a cloud of radioactive materials and the model for the thyroid dose due to inhalation of radioactive material.

A. Direct radiation from the source point is negligible compared to whole body radiation due to submersion in the radioactive materials cloud.

B. All radioactivity releases are treated as ground level releases regardless of the point of discharge.

C. The dose receptor is a standard man, as defined by the International Commission on Radiological Protection (ICRP).

D. Radioactive decay from the point of release to the dose receptor is neglected.

E. Isotopic data, such as decay rates and decay energy emissions, are taken from Table of Isotopes.

The isotopic data and standard man data are given in Tables 15.1.0-3 and 15.1.0-4. The atmospheric dilution factors used in the analysis of the environmental consequences of accidents are given in Table 15.1.0-5 for offsite doses and in Table 15.1.13-2 for control room doses.

15.1.0.5.3 Thyroid Inhalation Dose

The thyroid dose for a given time period is defined by the expression:

$$D = (X/Q)\,(B)\,[\Sigma_i\,(\underline{A}\cancel{Q}_i)\,(DCF_i)]$$

where

D = thyroid inhalation dose, rem

X/Q = site dispersion factor during time period, sec/m³

B = breathing rate during time period, m³/sec

$\underline{A}\cancel{Q}_i$ = total activity of iodine isotope i released in time period, curies

DCF_i = dose conversion factor for iodine isotope i, rem/curie inhaled.

15.1.0.5.4 Whole Body Dose

The whole body dose delivered to a dose receptor is obtained by considering the dose receptor to be immersed in a cloud containing radioactive material that is infinite in all directions above the ground plant, i.e., semi-infinite cloud. The concentration of radioactive material within this cloud is uniform and equal to the maximum centerline ground level concentration that would exist in the cloud at the approximate distance from the point of release.

The whole body dose due to gamma radiation and the whole body dose due to beta radiation for a given time period are defined by:

$$D_{wb} = (0.250)\ (X/Q)\ [\Sigma_i\ (\underline{A}\cancel{Q}_i)\ (E_i)]\ \text{(gamma)}$$

$$D_{wb} = (0.230)\ (X/Q)\ [\Sigma_i\ (\underline{A}\cancel{Q}_i)\ (E_i)]\ \text{(beta)}$$

where

D_{wb} = whole body dose of beta or gamma, rem

X/Q = site dispersion factor during time period, sec/m^3

$\underline{A}\cancel{Q}_i$ = total activity of isotope i released during time period, curies

E_i = average decay energy of isotope i, MeV/dis.

15.1.0.5.5 Subsequent Analysis to Support Replacement Steam Generator and Power Uprate

A radiological analysis was performed to support replacement steam generators and power uprate. The following inputs and assumptions used in this analysis differ from those listed in Sections 15.1.0.5.1 – 4. These differences are merely more conservative analysis assumptions than those identified above as the original analysis requirements.

A. A constant secondary side activity equal to 0.1 μCi/g DEQ I-131;

B. A constant primary side activity equal to 1.0 μCi/g DEQ I-131;

C. A constant primary side noble gas activity of $100/E_{bar}$ μCi/g for non-fuel failure analyses, where E_{bar} is defined as the average of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes other than iodines;

D. RCS activity for fuel failure analyses is based on the pin activities in Table 15.1.0-3C;

E. A continuous primary to secondary leak rate of 150 gallons per day per steam generator, except for events which result in a significant primary to secondary pressure differential (main steam line breaks and main feedwater line breaks) which use 0.5 gallons per minute;

F. An activity discharged through steaming determined by a time dependent mathematical model;

G. Isotopic data given by Tables 15.1.0-3A and B;

H. Whole Body dose consequences defined by:

$$D_{wb} = (X/Q) \times \sum_j A_j \times DCF_j$$

where:

D_{wb} = Whole body dose (rem)
A_j = Activity release of isotope j (Ci), for all isotopes
DCF_j = Whole Body Dose Conversion Factor isotope j $(rem - m^3/s - Ci)$
(X/Q) = Atmospheric dilution (s/m^3) from Table 15.1.0-5

ICRP-2 values for the DCF were used for events without fuel failure. These values are given in Table 15.1.0-3B. For these events, the DCF_j were calculated by:

$$DCF_j = DCF_{\gamma j} + DCF_{\beta j}$$

ICRP-30 values for the DCF_j were used for events with fuel failure. These values are given in Table 15.1.0-3A.

I. Thyroid dose consequences defined by:

$$D_{Thyroid} = (X/Q) \times B \times \sum_i A_{I,i} \times DCF_{I,i}$$

where:

$D_{Thyroid}$ = Thyroid dose (rem)
$A_{I,i}$ = Activity release of Iodine isotope i(Ci)
$DCF_{I,i}$ = Thyroid Dose Conversion Factor for Iodine Isotope i $(rem - m^3/s - Ci)$
B = Breathing Rate (m^3/s) from Table 15.1.0-4
(X/Q) = Atmospheric dilution (s/m^3) from Table 15.1.0-5

ICRP-2 values for the $DCF_{I,i}$ were used for events without fuel failure. These values are given in Table 15.1.0-3B.

ICRP-30 values for the DCF_{Ii} were used for events with fuel failure. These values are given in Table 15.1.0-3A.

J. Iodine Release from the Steam Generators was determined by:

For events that result in steam generator dryout, all of the iodine activity of the dry steam generator is released.

For all other events, an iodine partition factor of 100 is assumed.

K. For iodine spiking considerations in non-fuel failure postulated accident events, a pre-existing spike of 60 times the normal, and an event generated spike with a spiking factor of 500 assuming normal operation with one charging pump running;

L. A core power of 3087 MWt;

M. The Exclusion Area Boundary (EAB) doses are based on a 2 hour release (approximately 670,000 lbm). The Low Population Zone (LPZ) doses are based on an 8 hour cooldown to shutdown cooling entry conditions (approximately 1,770,000 lbm). Offsite releases are assumed to cease upon initiation of shutdown cooling.

15.1.0.6 Computer Programs

The computer programs for the analyses in this chapter are described below. The input data used in the execution of these programs is consistent with the plant design and the plant operating limits described previously.

15.1.0.6.1 CESEC

The CESEC computer program is used to simulate the NSSS. This program is described in References 7 and 13.

CESEC computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. Symmetric and asymmetric plant responses over a wide range of operating conditions can be determined by CESEC. The following is a partial list of the dynamic functions included in this NSSS simulation:

- point kinetics
- doppler and moderator reactivity feedback
- boron and CEA reactivity effects
- multi-node average and hot channel reactor core thermal hydraulics

For the loss of flow event, the CPC trip on pump low speed in conjunction with the initial margin reserved in COLSS is sufficient to prevent the violation of the DNBR SAFDL from any set of initial conditions.

15.1.5.2.3.3 Seized Rotor Event Analysis for RCS Flow Reduction and 30% Tube Plugging

When analyzing the seized rotor event, the event is initiated from a power operating limit with the minimal acceptable thermal margin to the DNBR limit. Based on this consideration, the initial RCS flow does not have a significant impact on the analysis results. Rather, the change in flow rate from the initial value to the final flow rate is a critical parameter. Due to the potential that increased tube plugging may affect the change in flow rate, an evaluation was performed to determine the effective change in flow rate due to 30% steam generator tube plugging.

This analysis concluded that the final "steady state" flow fraction for the 30% steam generator tube plugging case is essentially equal to the "steady state" flow fraction used in the analysis of record. The coastdown data for the seized rotor event was generated using the CENTS code. The use of the CENTS code is a change from the original coastdown analysis which used the COAST code.

The analysis of record seized rotor event assumes an instantaneous drop from the initial flow rate to the reduced "steady state" flow fraction. Based on the above, this assumption remains valid; therefore, a reanalysis of the seized rotor event was not required.

15.1.5.2.3.4 Cycle 15 Loss of Coolant Flow Resulting From a Pump Shaft Seizure

A subsequent radiological analysis was performed to support steam generator replacement and power uprate. Radiological consequences were calculated for a loss of AC power. These results will bound an AC power available case due to the unavailability of the condenser for steam release.

The analysis input and assumptions used in the calculation of the radiological dose releases for the seized shaft event are discussed in Section 15.1.0.5.5 and have been incorporated in this analysis with the following clarifications:

1. The condenser is assumed unavailable for cooldown (this is a conservative assumption with respect to the method defined in Section 15.1.5.2.2.2). Thus, the entire cooldown was performed by dumping steam to the atmosphere from the steam generators.

2. The radiological doses were conservatively calculated at a higher rated power of 3026 MWt (3087 MWt including uncertainties) and parametric in 0.5% fuel failure intervals.

3. An RCS primary to secondary leakage rate of 150 gpd per steam generator was assumed.

The effect of the increase in RCS and steam generator inventories, due to steam generator replacement, was combined with the 3026 MWt (3087 MWt including uncertainties) rated power physics radiological dose data to calculate the doses in fuel failure increments of 0.5%. The results of the analysis demonstrate that the EAB and LPZ radiological doses remain a small fraction (10%) of 10CFR100 limits up to 14% fuel failure. The calculated results for 14% fuel failure are presented in Table 15.1.5-10.

15.1.5.3 Conclusion

15.1.5.3.1 Loss of Coolant Flow Resulting From an Electrical Failure

For the cases of the loss of coolant flow arising from the simultaneous loss of power to four reactor coolant pumps or from loss of power to two reactor coolant pumps, the low DNBR trip assures that the minimum DNBR is maintained above its limits. Also, the study conducted to establish the maximum probable frequency decay rates has shown that the rates established are acceptable in their effect on DNBR due to reactor coolant pump speed effects.

15.1.5.3.2 Loss of Coolant Flow Resulting From a Shaft Seizure

For the loss of reactor coolant flow resulting from a seized shaft, the low DNBR trip assures that the radiological releases are less than 10CFR100 limits.

15.1.6 IDLE LOOP STARTUP

15.1.6.1 Identification of Causes

Idle loop startup is defined as the startup of a reactor coolant pump, without observance of prescribed operating procedures, assuming that both reactor coolant pumps in that loop were idle. The RCS consists of two loops connected parallel to the reactor vessel. Each loop includes two single suction, centrifugal pumps located between the steam generator outlet and the reactor vessel inlet nozzles. The pump motors have non-reversing mechanisms to prevent reverse rotation and also to limit backflow through the pump while the pump is out of service.

The Unit 2 plant was originally designed to permit continued operation with one or two reactor coolant pumps idle. The final Technical Specifications for Unit 2, however, precluded critical operation with any inoperative pumps. An analysis of the idle loop startup was completed prior to the initial issuance of the ANO-2 Technical Specifications, and is presented here for completeness.

15.1.6.2 Analysis of Effects and Consequences

15.1.6.2.1 Method of Analysis

Analysis of the idle loop startup incident was performed with the CESEC computer program, described in Section 15.1.0, for Cycle 1 operation.

The most adverse case involving startup of an idle reactor coolant pump results from EOC initial conditions with two reactor coolant pumps operating in one loop (both reactor coolant pumps idle in the other loop), and with reactor power at nominal conditions for 2-pump operation. At time zero, one of the pumps is started.

In addition to the parameters described in Section 15.1.0, the conservative assumptions given in Table 15.1.6-1 are used for this analysis.

The results of these subsequent analyses shows that the peak RCS and secondary side pressures are maintained less than 110% of design values.

15.1.7.4.2 Cycle 15 Loss of External Load and/or Turbine Analysis

A subsequent radiological analysis was performed to support steam generator replacement and power uprate. No radiological doses were explicitly calculated for this event due to the bounding nature of the MSLB and FWLB doses.

15.1.8 LOSS OF NORMAL FEEDWATER FLOW

15.1.8.1 Identification of Cause

The loss of normal feedwater flow is defined as a reduction in feedwater flow to the steam generators when operating at power, without a corresponding reduction in steam flow from the steam generators. The result of this mismatch is a reduction in the water inventory in the steam generators.

The condensate and feedwater system is described in Section 10.4.7 and the emergency feedwater system in Section 10.4.9. The emergency feedwater system is available to automatically provide sufficient feedwater flow to remove residual heat generation from the RCS following RT from rated power. This system consists of one motor-driven and one turbine-driven emergency feedwater pump, and a non-safety Auxiliary Feedwater pump.

A complete loss of both main feedwater pumps or a complete loss of all four condensate pumps results in the loss of all normal feedwater. Closure of the Main Feedwater Block valves or all feedwater regulating and regulating bypass valves also results in loss of normal feed flow.

The PPS provides protection against loss of the secondary heat sink by the steam generator low water level trip and automatic initiation of the emergency feedwater system. The high pressurizer pressure trip provides protection in the event that the RCS pressure limit is approached.

15.1.8.2 Analysis of Effects and Consequences

15.1.8.2.1 Methods of Analysis

For the loss of feedwater flow analysis, a complete loss of feedwater flow is assumed, since this condition requires the most rapid response from the PPS.

The analysis of a complete loss of feedwater was performed with the CESEC computer program, described in Section 15.1.0.6. Table 15.1.8-1 lists the conservative assumptions made for this analysis.

15.1.8.2.2 Results

The loss of normal feedwater flow is analyzed by assuming an instantaneous complete stoppage of feedwater flow to both steam generators. The emergency feedwater system is automatically

equivalent curies per second and the I^{131} release rate is less than 5.0 x 10^{-6} dose equivalent curies per second. If this situation were to continue for two hours, the total releases would be less than 0.036 dose equivalent curies of I^{131} and less than 12.2 dose equivalent curies of Xe^{133}. For this situation, the inhalation dose at the site boundary is conservatively evaluated to be 1.87 x 10^{-2} rem and the whole body dose is 5.06 x 10^{-2}rem.

15.1.9.3 Conclusion

Analysis shows that for the loss of normal and preferred AC power the minimum hot channel DNBR during the transient is not less than 1.3. The radiological consequences are significantly less than 10CFR100 limits.

15.1.9.4 Loss of All Normal and Preferred AC Power Subsequent Analyses

15.1.9.4.1 Cycle 15 Loss of All Normal and Preferred AC Power Analysis

A subsequent radiological analysis was performed to support steam generator replacement and power uprate. No radiological doses were explicitly calculated for this event due to the bounding nature of the MSLB and FWLB doses.

15.1.10 EXCESS HEAT REMOVAL DUE TO SECONDARY SYSTEM MALFUNCTION

15.1.10.1 Identification of Causes

Excess heat removal due to secondary system malfunction can occur as a result of feedwater system or main system valve malfunction.

Excess heat removal causes a decrease in the temperature of the reactor coolant, an increase in reactor power due to the negative moderator temperature coefficient and a decrease in the RCS and steam generator pressures. Detection of these conditions is accomplished by the RCS and steam generator pressure alarms and the high reactor power alarm.

Protection against the violation of specified acceptable fuel design limits as a consequence of an excessive heat removal accident is provided by the low DNBR and high local power density trips.

15.1.10.1.1 Excess Heat Removal Due to Feedwater System Malfunction

Excess heat removal due to feedwater system malfunction may be caused by:

A. Loss of one of several feedwater heaters. The loss could be due to interruption of steam extraction flow. The high pressure heaters are conservatively assumed to increase the feedwater enthalpy by 54 Btu/lb at full load. In order to lose this heating, four valves (one per extraction line) would need to be operated. The loss of any of the low pressure heaters before the feedwater pumps will produce a lesser effect due to the compensating effect of the high pressure heater in that cycle.

A conservative decontamination factor of 100 was assumed for the iodine concentration released in the steam from the intact steam generator liquid. The secondary side initial steady state radiological concentration was assumed to be 0.10 μCi/gm dose equivalent I-131. The primary side specific activity was assumed to be 60.0 μCi/gm dose equivalent I-131 for the pre-accident case. An initial primary system release rate that results in an initial concentration of 1.0 μCi/gm dose equivalent I-131 was based on make-up flow of 44 gpm, for the accident induced iodine spike. A primary side specific activity equal to 100/E μCi/gm was assumed for the non-iodine concentration in both of the calculations. The iodine physical data presented in Table 15.1.14-37 was assumed in this analysis.

To determine the radioactive release for the main steam line break accident, HZP mass releases were used with decay heat considerations based on full power. The Cycle 12 HZP case presented above was used in this assessment. The blowdown data is based on a MSLB inside containment upstream of the flow limiting venturi. This blowdown information was used assuming the break was located outside containment but upstream of the main steam isolation valves. This approach is considered conservative as no credit is taken for the flow limiting venturi. A break in the main steam line outside containment and upstream of the main steam line isolation valves is assumed to result in the maximum radioactive release for this accident.

Cooldown of the plant following the accident is conservatively assumed to take place using the atmospheric dump valves. This results in additional release due to the venting of steam directly to the atmosphere. Also, it is assumed that the iodine transported through the assumed primary-to-secondary leak in the ruptured steam generator is discharged directly to atmosphere. A 0.5 gpm primary-to-secondary leak is assumed in the ruptured steam generator and a 0.5 gpm primary-to-secondary leak is assumed in the intact steam generator.

Since it is assumed that all the iodine contained in the damaged steam generator exits through the rupture, the iodine release calculated for this accident is conservative. No credit is taken for decontamination in the damaged unit.

The resulting 2-hour and 8-hour thyroid dose for both cases is less than 10.0 rem and 5.0 rem, respectively. This resulting 2-hour and 8-hour whole body dose for both cases is less than 0.03 rem and 0.01 rem respectively. These results are well within 10CFR100 limits and are considered acceptable.

15.1.14.1.4.6 Cycle 15 Main Steam Line Break Analysis

A subsequent radiological analysis was performed to support steam generator replacement and power uprate.

The analysis input and assumptions used in the calculation of the radiological dose releases for the HFP and HZP MSLB events are discussed in Section 15.1.0.5.5 and have been incorporated in this analysis with the following clarifications:

1. A main steam line break location outside containment but upstream of the MSIVs was assumed.

2. The condenser is assumed unavailable for cooldown due to a loss of offsite power. Thus, the entire cooldown was performed by dumping steam to the atmosphere from the steam generators.

3. The affected steam generator was assumed to boil dry and is a direct source to the atmosphere for all isotopes carried by the tube leakage. The analysis conservatively assumed a decontamination factor of 1.0 for the affected steam generator.

The radiological doses for the Exclusion Area Boundary and Low Population Zone for an event generated iodine spike and no iodine spike are less than a small fraction of the 10CFR100 limits of 30 Rem for the thyroid and 2.5 Rem for whole body, and for a pre-existing iodine spike are within the 10CFR100 limits of 300 Rem for thyroid and 25 Rem for whole body. The calculated results for all doses are presented in Tables 15.1.14-38 and 15.1.14-39.

15.1.14.2 Feedwater Line Break Accident

15.1.14.2.1 Identification of Causes

A feedwater line rupture accident is defined as the failure of a main feedwater system pipe during plant operation. The main feedwater and condensate system on which these analyses are based, are described in Section 10.4.7. A rupture in the main feedwater system rapidly reduces the steam generator inventory causing a partial loss of the main steam heat sink, thereby allowing heatup of the RCS. Depending on initial conditions, break size, break location and steam generator inventory, any of several plant protective system actions may occur. A decrease in the steam generator water level will initiate a reactor trip signal on low steam generator water level. In addition, the decrease in the steam generator pressure may result in a low steam generator pressure trip signal and cause the main steam isolation valves and the main feedwater isolation valves to close. Additional protection against loss of the main steam heat sink is provided by automatic initiation of emergency feedwater to the intact steam generator. The RCS is protected from overpressurization by the high RCS pressurizer pressure trip and the pressurizer safety valves.

If the feedwater line breaks outside of containment or inside containment but upstream of the feedwater line check valves, steam generator blowdown is prevented by the closure of the check valves. The consequences of these feedwater line breaks are the same as the consequences of the loss of normal feedwater flow incidents (Section 15.1.8).

If the feedwater line rupture occurs between the steam generator and the feedwater line check valves, blowdown of the affected steam generator continues until the steam generator pressure equals the containment back pressure. However, termination of the feedwater flow from the intact steam generator as well as the intact lines on the damaged steam generator occurs with closure of the check valves. In addition, the main feedwater isolation valves close on a main steam isolation signal.

The steam generators are designed to withstand RCS operating pressure on the tube side with atmospheric pressure on the shell side; therefore, the integrity of the RCPB is assured.

15.1.14.2.4.3 Cycle 15 Feedwater Line Break Analysis

A subsequent radiological analysis was performed to support steam generator replacement and power uprate.

The analysis input and assumptions used in the calculation of the radiological dose releases for the FWLB event are discussed in Section 15.1.0.5.5 and have been incorporated in this analysis with the following clarifications:

1. The condenser is assumed unavailable for cooldown due to the loss of offsite power. Thus, the entire cooldown was performed by dumping steam to the atmosphere from the steam generators.

2. Because of the location of the feedwater check valves, only inside containment FWLB are considered. This prevents direct release of the inventory from the ruptured steam generator. However, no credit was taken for hold-up in containment.

3. Due to the tremendous loss of feedwater associated with the event, there is a possibility that both steam generators could reach dry-out. Thus, the analysis conservatively assumed a decontamination factor of 1.0 for both steam generators when steaming the plant.

The radiological doses for the Exclusion Area Boundary and Low Population Zone are less than a small fraction of the 10CFR100 limits of 30 Rem for the thyroid and 2.5 Rem for whole body. The calculated results for all doses are presented in Table 15.1.14-40.

15.1.14.3 Additional Main Steam Line/Feedwater Line Break Information and Analyses

Additional analyses and information are contained in correspondence to the NRC. These are included in the reference section at the end of this chapter.

15.1.15 INADVERTENT LOADING OF A FUEL ASSEMBLY INTO THE IMPROPER POSITION

15.1.15.1 Identification of Causes

Two accidents are considered in this section: 1) the erroneous loading of fuel pellets or fuel rods of different enrichment in a fuel assembly; and, 2) the erroneous placement or orientation of fuel assemblies.

The likelihood of an error in assembly, fabrication, or core loading is considered to be extremely remote because of the extensive quality control and quality surveillance programs employed during the fabrication process as well as the strict procedural control used during core loading. However, even if the core were to have incorrectly placed fuel rods or assemblies, these would either be detectable from the results of the startup or would lead to a minimal number of rods with excessive power during full power operation.

Table 15.1.0-3A

ICRP-30 DATA FOR ISOTOPES

Isotope	Thyroid DCF (Rem/Ci)	Whole Body γ DCF (rem-m^3/Ci-s)
I-131	1.1E+06	
I-132	6.3E+03	
I-133	1.8E+05	
I-134	1.1E+03	
I-135	3.1E+04	
Kr-85		3.31E-04
Kr-85m		2.31E-02
Kr-87		1.33E-01
Kr-88		3.38E-01
Xe-131m		1.25E-03
Xe-133		4.96E-03
Xe-133m		4.29E-03
Xe-135		3.59E-02
Xe-135m		6.37E-02
Xe-138		1.87E-01

TABLE 15.1.0-3B

ICRP-2 DATA FOR ISOTOPES

Isotope	Thyroid DCF (Rem/Ci)	Whole Body γ DCF (rem-m^3/Ci-s)	Whole Body β DCF (rem-m^3/Ci-s)
I-131	1.48E+06	9.30E-02	4.49E-02
I-132	5.35E+04	5.98E-01	9.71E-02
I-133	4.00E+05	1.60E-01	9.38E-02
I-134	2.50E+04	4.58E-01	1.26E-01
I-135	1.24E+05	4.43E-01	7.08E-02
Kr-85		5.28E-04	5.11E-02
Kr-85m		3.80E-02	5.59E-02
Kr-87		3.55E-01	2.42E-01
Kr-88		4.35E-01	7.82E-02
Xe-131m		6.78E-03	3.15E-02
Xe-133		1.24E-02	3.36E-02
Xe-133m		1.42E-02	4.07E-02
Xe-135		6.20E-02	7.27E-02
Xe-135m		1.07E-01	2.25E-02
Xe-138		2.74E-01	2.76E-01

TABLE 15.1.0-3C

FUEL PIN ACTIVITIES

Isotope	Maximum Activity (Ci/pin)
I-131	2.002E+03
I-132	2.882E+03
I-133	4.072E+03
I-134	4.517E+03
I-135	3.788E+03
Kr-85	2.281E+01
Kr-85m	6.473E+02
Kr-87	1.279E+03
Kr-88	1.805E+03
Xe-131m	2.249E+01
Xe-133	4.055E+03
Xe-133m	1.263E+02
Xe-135	1.055E+03
Xe-135m	7.993E+02
Xe-138	3.540E+03

TABLE 15.1.5-10

RADIOLOGICAL DOSE RESULTS FOR CYCLE 15 REACTOR COOLANT PUMP SHAFT SEIZURE ASSUMING 14% FUEL FAILURE

Radiological Dose	Rem
Thyroid	
EAB	5
LPZ	3
Whole Body	
EAB	1
LPZ	0.1

Table 15.1.14-37

PHYSICAL DATA FOR ISOTOPES

Isotope Symbol	Half Life	Average Energy per disintegration (MeV/Dis)		Thyroid Dose Conversion Factor	
		Gamma	Beta	(Rem/μCi)	(DEQ_{131})
I-131	8.1 d	0.372	0.195	1.480	1.000
I-132	2.3 h	2.390	0.422	0.0535	0.0362
I-133	20 h	0.639	0.408	0.400	0.2703
I-134	52 m	1.830	0.548	0.025	0.0169
I-135	6.7 h	1.770	0.308	0.124	0.0838

Table 15.1.14-38

NO IODINE SPIKE AND EVENT GENERATED IODINE SPIKE RADIOLOGICAL DOSE RESULTS FOR CYCLE 15 MAIN STEAM LINE BREAK EVENT

Radiological Dose	No Iodine Spike, Rem	Event Generated Iodine Spike, Rem
Thyroid		
EAB	5	9
LPZ	0.3	3
Whole Body		
EAB	<0.1	<0.1
LPZ	<0.1	<0.1

TABLE 15.1.14-39

PRE-EXISTING IODINE SPIKE RADIOLOGICAL DOSE RESULTS FOR CYCLE 15 MAIN STEAM LINE BREAK EVENT

Radiological Dose	Pre-existing Iodine Spike, Rem
Thyroid	
EAB	10
LPZ	2
Whole Body	
EAB	<0.1
LPZ	<0.1

TABLE 15.1.14-40

RADIOLOGICAL DOSE RESULTS FOR THE CYCLE 15 FEEDWATER LINE BREAK EVENT

Radiological Dose	No Iodine Spiking, Rem
Thyroid	
EAB	9
LPZ	0.5
Whole Body	
EAB	<0.1
LPZ	<0.1

ENCLOSURE 3

TO

2CAN119901

ECCS PERFORMANCE ANALYSIS

1 ECCS Performance

An Emergency Core Cooling System (ECCS) performance analysis was performed to demonstrate conformance to 10 CFR 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors (Reference 1-1), for Arkansas Nuclear One – Unit 2 (ANO-2) during operation with replacement steam generators (RSG). Analyses were performed for the limiting large break Loss-of-Coolant Accident (LOCA) and for a spectrum of small break LOCAs.

The current ECCS performance analysis for Cycle 14 was performed assuming a reactor coolant system (RCS) flow of 107.8 x 10^6 lbm/hr and low pressurizer pressure reactor trip and safety injection actuation signal (SIAS) setpoint of 1400 psia, which supports the proposed Technical Specification (TS) changes. However, this analysis is modeled with the original steam generator in a degraded condition. To support a reduced low pressurizer pressure setpoint and credit an increase in RCS flow, the following analyses have been performed.

Sections 1.1 and 1.2 summarize the large break LOCA and small break LOCA analyses that were performed. The summaries include a description of the methodology and results of the analyses. The conclusions of the ECCS performance analysis are presented in Section 1.3.

1.1 Large Break LOCA Evaluation

1.1.1 Methodology Used for Evaluation

The large break LOCA ECCS performance analysis was performed using the NRC accepted ABB CENP's June 1985 Evaluation Model (Reference 1-3). This is the same methodology used in the current ANO-2 large break LOCA ECCS performance analysis described in Section 6.3.3.2.2 of the ANO-2 Safety Analysis Report (SAR) (Reference 1-4). The Safety Evaluation Reports (SER) that document NRC acceptance of the evaluation model are found in References 1-5 through 1-7.

In the June 1985 Evaluation Model, the CEFLASH-4A computer code (Reference 1-8) is used to perform the blowdown hydraulic analysis of the RCS, and the COMPERC-II computer code (Reference 1-9) is used to perform the RCS refill/reflood hydraulic analysis and to calculate the containment pressure. The model is also used in conjunction with the methodology described in Reference 1-10 to calculate the FLECHT-based reflood heat transfer coefficients used in the hot rod heatup analysis. The HCROSS (Reference 1-11) and PARCH (Reference 1-12) computer codes are used to calculate steam cooling heat transfer coefficients. The hot rod heatup analysis which calculates the peak cladding temperature and the maximum cladding oxidation is performed using the STRIKIN-II computer code (Reference 1-13). Core-wide cladding oxidation is calculated using the COMZIRC computer code (Appendix C of Supplement 1 of Reference 1-9). The initial steady state fuel rod conditions used in the analysis are determined using the FATES3B computer code (Reference 1-14). The SERs for the large break LOCA ECCS performance analysis computer codes are documented in References 1-5, 1-6, 1-7, and 1-15 through 1-18. The SERs for the FATES3B computer code are documented in Reference 1-19.

The analysis was performed for a 0.6 Double-Ended Guillotine break in the reactor coolant Pump Discharge leg (0.6 DEG/PD). This is the limiting break of the large break LOCA spectrum analysis documented in Section 6.3.3.2.2 of the ANO-2 SAR. This analysis was performed at a hot rod average burnup of 500 MWD/MTU.

The most limiting single failure of the ECCS in the large break LOCA analysis is *no* failure to the ECCS. No failure is the worst case condition because the amount of safety injection that spills into the containment is maximized. This acts to minimize containment pressure, in turn, minimizing the rate at which the core is reflooded. Any failure to the ECCS that reduces safety injection flow is not the worst case condition because sufficient flow remains available to maintain the reactor vessel downcomer filled to the cold leg nozzles. Such a failure will maintain the same driving force for reflooding the core as does a *no* failure, yet will result in less spillage into the containment. No failure to the ECCS is also the limiting condition analyzed in the current large break LOCA analysis documented in the ANO-2 SAR. Other important core, RCS, and ECCS parameters used in the large break LOCA analysis are listed in Table 1.1-1.

The analysis has been performed based on a low pressurizer pressure setpoint of 1400 psia. Due to the quick rate of depressurization and voiding in the core, credit for a low pressurizer pressure trip setpoint results in a minimal impact on the analysis. Conservative modeling assumptions with respect to ECCS spillage and safety injection tank (SIT) flow to the core prior to high pressure safety injection (HPSI) and low pressure safety injection (LPSI) minimize the impact of a low pressurizer pressure SIAS setpoint of 1400 psia.

1.1.2 Results of Evaluation

Results of the large break LOCA analysis of the RSGs are presented in Table 1.1-2 and Table 1.1-3, and in Figures 1.1-1 through 1.1-19. Table 1.1-2 lists the peak cladding temperature and oxidation percentages for the analysis. Times of interest are listed in Table 1.1-3. The results demonstrate conformance to the following ECCS acceptance criteria:

Parameter	Criterion	Result
Peak Cladding Temperature	≤2200°F	2029°F
Maximum Cladding Oxidation	≤17%	5.4%
Maximum Core-Wide Oxidation	≤1%	<0.99%
Coolable Geometry	Yes	Yes

The analysis is applicable to ANO-2 operation with the RSGs, a RCS flow rate of 118. X 10^6 lbm/hr, a low pressurizer pressure reactor trip and SIAS setpoint of 1400 psia, a core power of 2900 MWt (rated core power of 2815 MWt and a 3% power measurement uncertainty), and assuming operation at a Peak Linear Heat Generation Rate (PLHGR) of 13.5 KW/ft.

1.2 Small Break LOCA Evaluation

1.2.1 Methodology Used for Evaluation

The small break LOCA analysis was performed with the Supplement 2 Model (S2M) of the ABB CENP small break LOCA evaluation model (Reference 1-20). This is the same methodology used in the current ANO-2 small break LOCA ECCS performance analysis described in Reference 1-21. The SERs that document NRC acceptance of the evaluation model may be found in References 1-5, 1-22, and 1-23.

In the S2M evaluation model, the CEFLASH-4AS computer program (Reference 1-24) is used to perform the hydraulic analysis of the RCS until the time the SITs begin to inject. After injection from the SITs begins, the COMPERC-II computer program (Reference 1-9) is used to perform the hydraulic analysis. The hot rod cladding temperature and maximum cladding oxidation are calculated by the STRIKIN-II computer program (Reference 1-13) during the initial period of forced convection heat transfer and by the PARCH computer program (Reference 1-12) during the subsequent period of pool boiling heat transfer. Core-wide cladding oxidation is conservatively represented as the rod-average cladding oxidation of the hot rod. The initial steady state fuel rod conditions used in the analysis are determined using the FATES3B computer program (Reference 1-14). The SERs for the small break LOCA ECCS performance analysis computer codes are noted in References 1-5, 1-15 through 17, 1-22, and 1-23. The SERs for the FATES3B computer code are documented in Reference 1-19.

The analysis was performed for three break sizes in the reactor coolant pump (RCP) discharge leg, namely, 0.03 ft^2, 0.04 ft^2, and 0.05 ft^2. The 0.04 ft^2/PD break, which is the limiting break in the current ANO-2 small break LOCA ECCS performance analysis, continued to be the limiting small break LOCA in this analysis.

In the small break LOCA analysis it is assumed that offsite power is lost coincident with reactor trip and, therefore, the HPSI and LPSI pumps must await emergency diesel generator (EDG)startup and load sequencing prior to start. The total delay time assumed is 40 seconds from the time the pressurizer pressure reaches the SIAS setpoint to the time that the HPSI pumps are at speed and aligned to the RCS. For breaks in the RCP discharge leg, all safety injection flow delivered to the broken leg is modeled to spill out the break.

The most limiting single failure of the ECCS in the small break LOCA analysis is the failure of an EDG. This failure causes the loss of one HPSI and one LPSI pump, resulting in minimum safety injection water being available to cool the core. Based on EDG failure and the design of the ANO-2 ECCS, 75% of the flow from one HPSI pump is credited in the small break LOCA analysis. The LPSI pumps are not explicitly credited in the small break LOCA analysis since the RCS pressure never decreases below the LPSI pump shutoff head during the portion of the transient that is analyzed. However, 50% of the flow from one LPSI pump is available to cool the core given a failure of an EDG and a break in an RCP discharge leg. Other important core, RCS, and ECCS parameters used in the small break LOCA analysis are listed in Table 1.2-1 and Table 1.2-2.

1.2.2 Results of Evaluation

Results of the small break LOCA analysis of the RSGs are presented in Table 1.2-3 and Table 1.2-4, and in Figures 1.2-1 through 1.2-24. Table 1.2-3 lists the peak cladding temperature and oxidation percentages for the three breaks analyzed. Times of interest are listed in Table 1.2-4. The results demonstrate conformance to the following ECCS acceptance criteria:

Parameter	Criterion	Result
Peak Cladding Temperature	≤2200°F	1905°F
Maximum Cladding Oxidation	≤17%	6.68%
Maximum Core-Wide Oxidation	≤1%	<0.50%
Coolable Geometry	Yes	Yes

The analysis is applicable to ANO-2 operation with the RSGs, a RCS flowrate of 117.4 x 10^6 lbm/hr, a low pressurizer pressure reactor trip and SIAS setpoint of 1400 psia, a core power of 2900 MWt (rated core power of 2815 MWt and a 3% power measurement uncertainty), and with a PLHGR of 13.5 KW/ft.

1.3 Conclusion

An ECCS performance analysis has been performed for ANO-2 assuming operation with RSGs. The analysis included consideration of both a large and small break LOCA. The limiting break size, i.e., the break size that results in the most elevated peak cladding temperature, was determined to be the 0.6 DEG/PD break.

The results of the analysis demonstrate conformance to the ECCS acceptance criteria during operation with RSGs, a RCS flowrate of 118 x 10^6 lbm/hr, a low pressurizer pressure reactor trip and SIAS setpoint of 1400 psia, a PLHGR of 13.5 KW/ft, and a core power of 2900 MWt (rated core power of 2815 MWt and a 3% power measurement uncertainty).

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Table 1.1-1
Important Core and Plant Design Data Used in the
ANO-2 RSG Large Break LOCA ECCS Performance Analysis

Quantity	Value	Units
Reactor power level (103% of rated power)	2900	MWt
Peak linear heat generation rate (PLHGR) of the hot rod	13.5	KW/ft
PLHGR of the average rod in assembly with hot rod	12.73	KW/ft
Gap conductance at the PLHGR[1]	1610	BTU/hr-ft^2-°F
Fuel centerline temperature at the PLHGR[1]	3319	°F
Fuel average temperature at the PLHGR[1]	2103	°F
Hot rod gas pressure[1]	1133	psia
Moderator temperature coefficient at initial density	$+0.5 \times 10^{-4}$	$\Delta\rho$/°F
RCS flow rate	118.0×10^6	lbm/hr
Core flow rate	113.9×10^6	lbm/hr
RCS pressure	2200	psia
Cold leg temperature	540.0	°F
Hot leg temperature	603.3	°F
Safety injection tank pressure (min/max)	550/650	psia
Safety injection tank water volume (min/max)	1350/1600	ft^3
Low pressure safety injection pump flow rate (min, 1 pump/max, 2 pump)	3222/7540	gpm
High pressure safety injection pump flow rate (min, 1 pump/max, 2 pump)	678/1674	gpm

[1] These quantities correspond to the rod average burnup of the hot rod (500 MWD/MTU) that yields the highest peak cladding temperature.

Table 1.1-2
ANO-2 RSG Large Break LOCA ECCS Performance Analysis Results

Break Size	Peak Cladding Temperature (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
0.6 DEG/PD	2029	5.4	<0.99

Table 1.1-3
Times of Interest for the
ANO-2 RSG Large Break LOCA ECCS Performance Analysis
(seconds after break)

Break Size	SITs On	End of Bypass	Start of Reflood	SITs Empty	Hot Rod Rupture
0.6 DEG/PD	13.4	19.2	31.1	59.3	32.2

Table 1.2-1
Important Core and Plant Design Data Used in the
ANO-2 RSG Small Break LOCA ECCS Performance Analysis

Quantity	Value	Units
Reactor power level (103% of rated power)	2900	MWt
Peak linear heat generation rate (PLHGR)	13.5	KW/ft
Axial shape index	-0.3	~~asiu-~~
Gap conductance at PLHGR	1573	BTU/hr-ft^2-°F
Fuel centerline temperature at PLHGR	3333	°F
Fuel average temperature at PLHGR	2114	°F
Hot rod gas pressure	1123	psia
Moderator temperature coefficient at initial density	0.0×10^{-4}	$\Delta\rho$/°F
RCS flow rate	117.4×10^6	lbm/hr
Core flow rate	113.3×10^6	lbm/hr
RCS pressure	2200	psia
Cold leg temperature	556.7	°F
Hot leg temperature	618.1	°F
Plugged tubes per steam generator	10	%
MSSV first bank opening pressure	1130.4	psia
Low pressurizer pressure reactor trip setpoint	1400	psia
Low pressurizer pressure SIAS setpoint	1400	psia
HPSI Flow Rate	Table 1.2-2	gpm
Safety injection tank pressure	550	psia

Table 1.2-2
High Pressure Safety Injection Pump
Minimum Delivered Flow to RCS
(Assuming Failure of an Emergency Diesel Generator)

RCS Pressure, psia	Flow Rate, gpm
14.7	738.7
22	736.6
31	733.3
35	732.2
46	729.0
191	680.4
327	631.8
456	583.2
577	534.6
692	486.0
800	437.4
899	388.8
990	340.2
1071	291.6
1142	237.6
1201	172.8
1248	102.6
1269	54.0
1281	0.0

Notes:
1. The flow is assumed to be divided equally to each of the four discharge legs.
2. The flow to the broken discharge leg is assumed to spill out the break.

Table 1.2-3
ANO-2 RSG Small Break LOCA ECCS Performance Analysis Results

Break Size	Peak Cladding Temperature (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
0.03 ft^2/PD	1777	2.56	<0.34
0.04 ft^2/PD	1905	6.68	<0.50
0.05 ft^2/PD	1673	1.70	<0.24

Table 1.2-4
Times of Interest for the
ANO-2 RSG Small Break LOCA ECCS Performance Analysis
(seconds after break)

Break Size	HPSI Flow Delivered to RCS	LPSI Flow Delivered to RCS	SIT Flow Delivered to RCS	Peak Cladding Temperature Occurs
0.03 ft^2/PD	279	(a)	(c)	2219
0.04 ft^2/PD	226	(a)	2136[(b)]	1857
0.05 ft^2/PD	191	(a)	1570[(b)]	1624

(a) Calculation completed before LPSI flow delivery to RCS begins.
(b) SIT injection calculated to begin but not credited in analysis.
(c) Calculation completed before SIT injection begins.

Figure 1.1-1

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Core Power

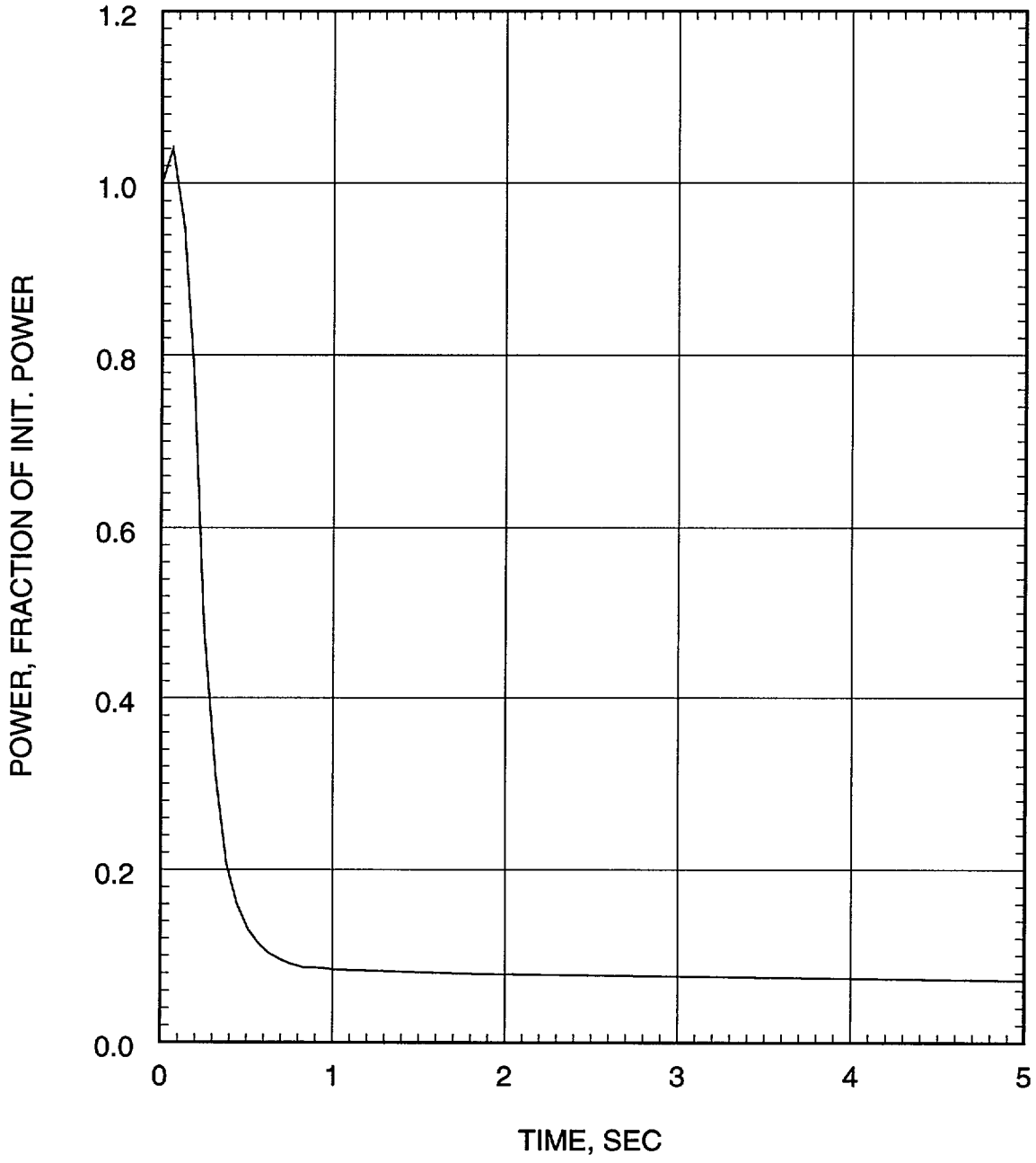


Figure 1.1-2

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Pressure in Center Hot Assembly Node

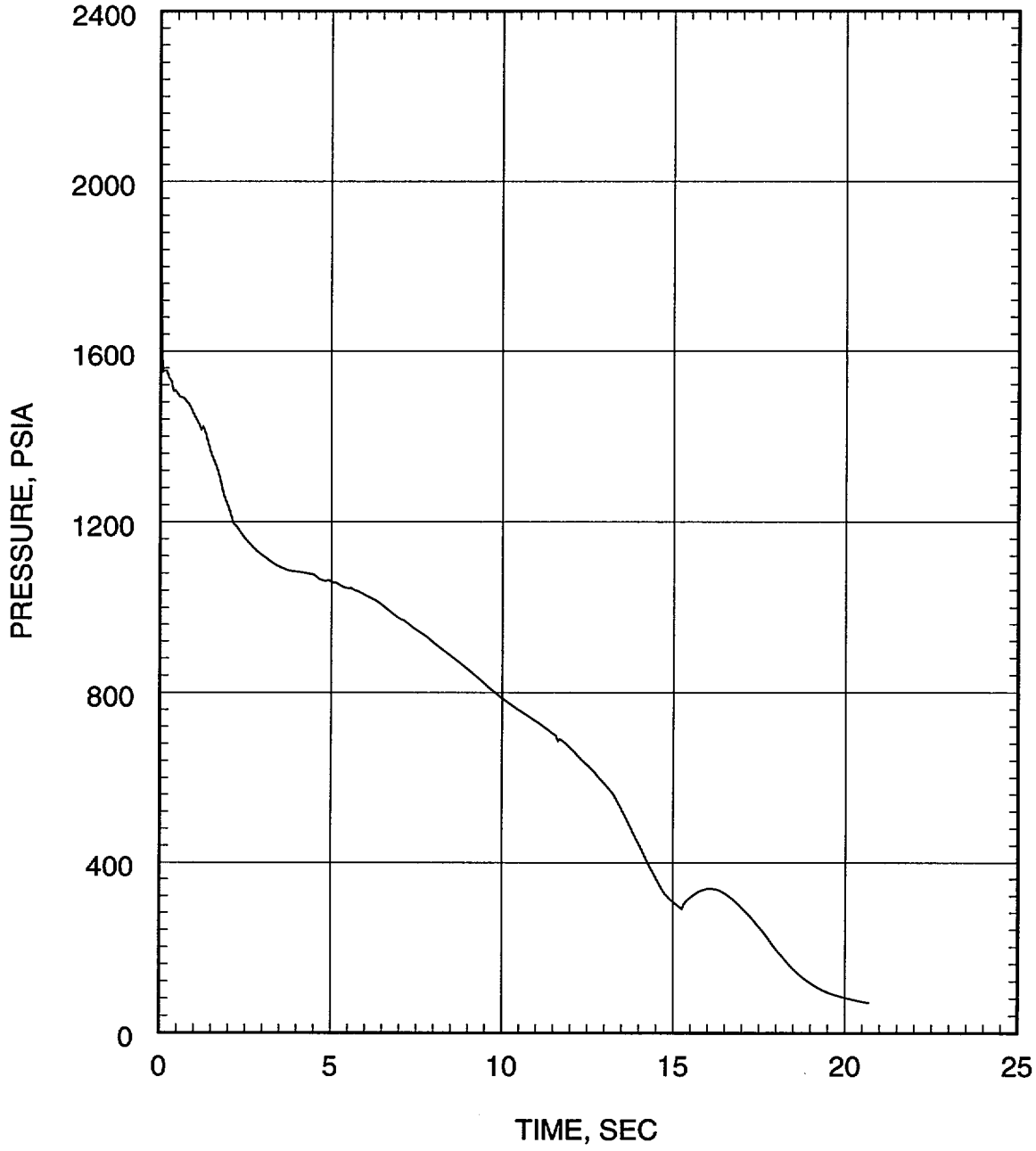


Figure 1.1-3

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Leak Flow Rate

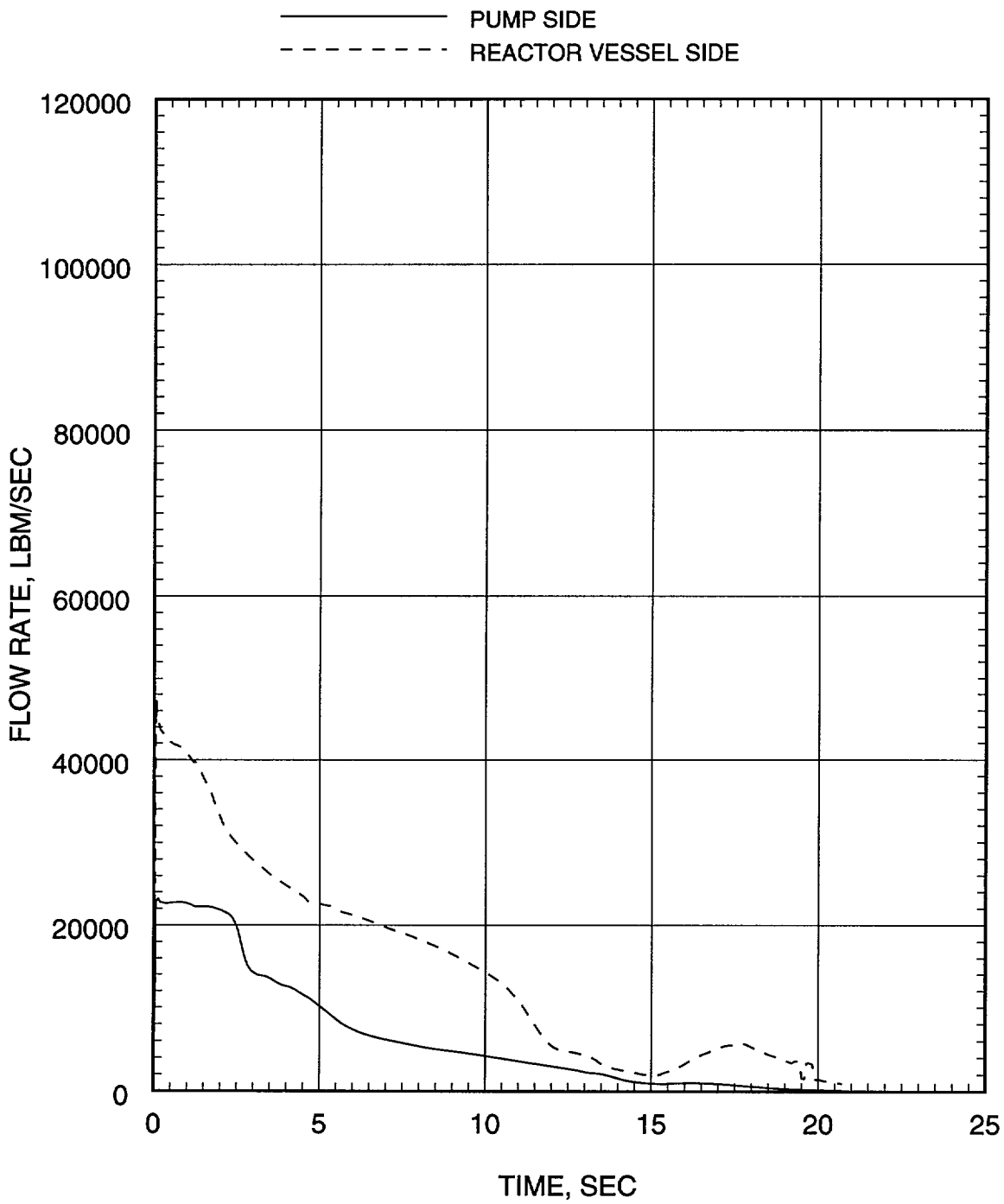


Figure 1.1-4

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Hot Assembly Flow Rate (Below Hot Spot)

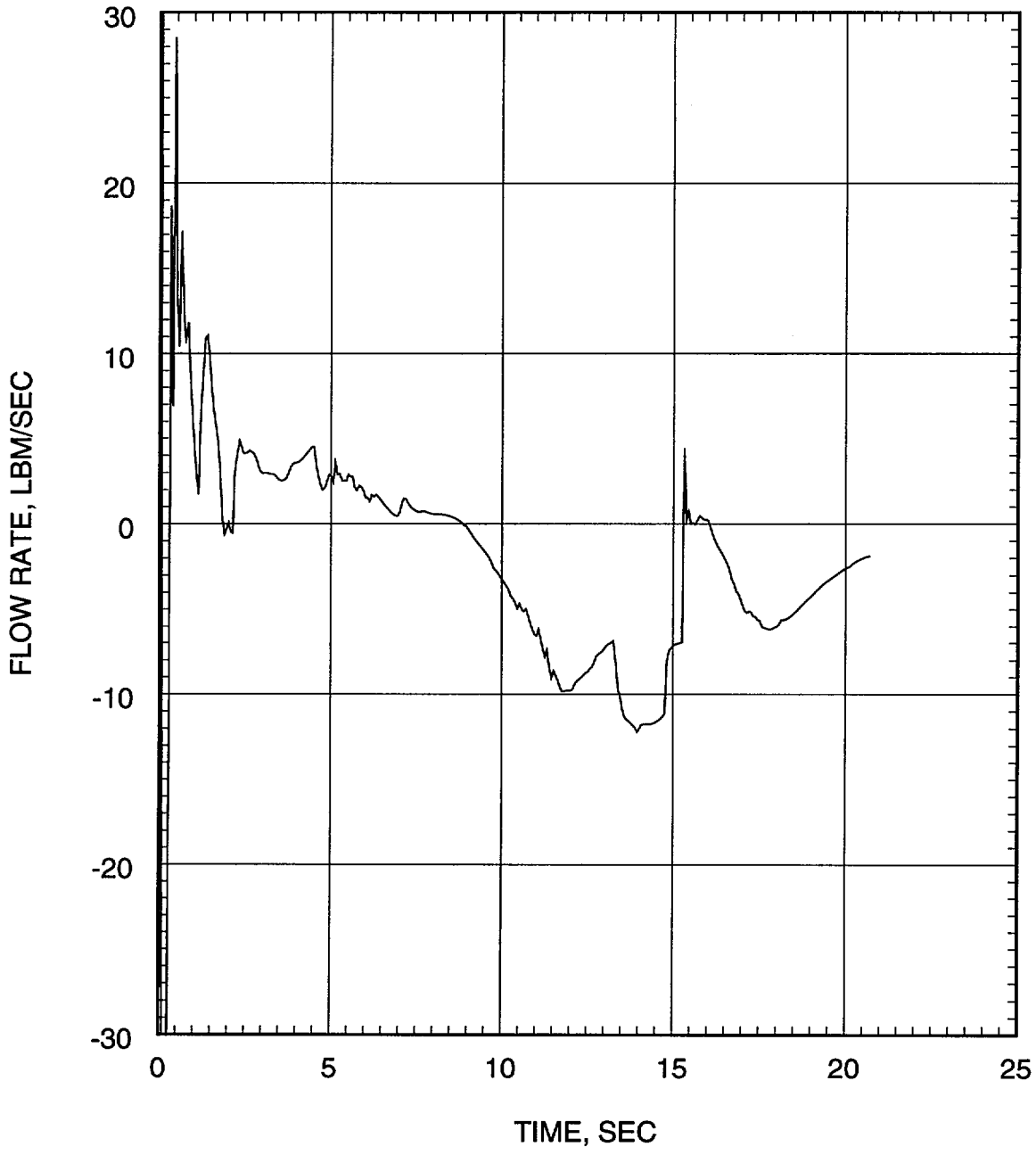


Figure 1.1-5

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Hot Assembly Flow Rate (Above Hot Spot)

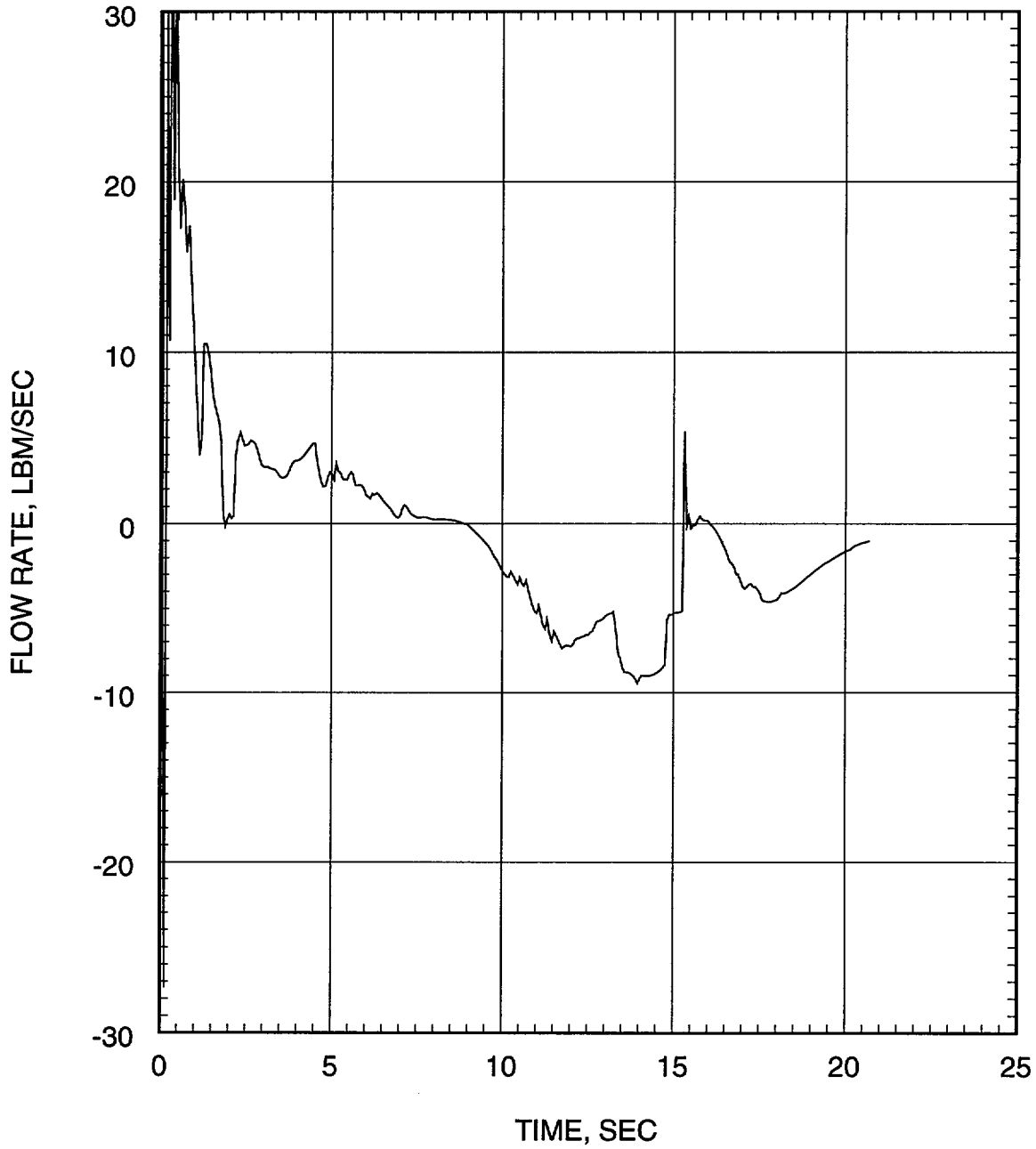


Figure 1.1-6

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Hot Assembly Quality

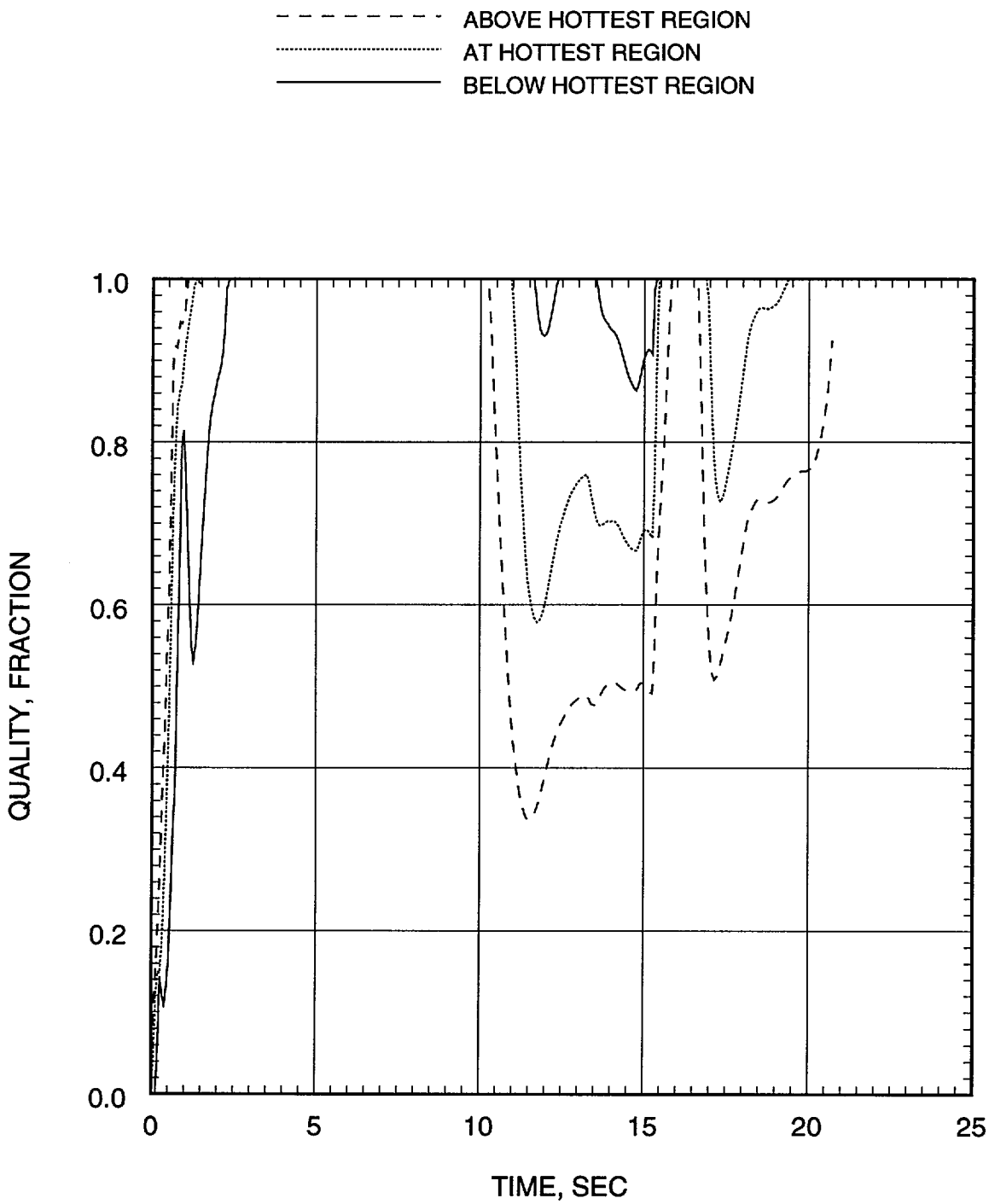


Figure 1.1-7

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Containment Pressure

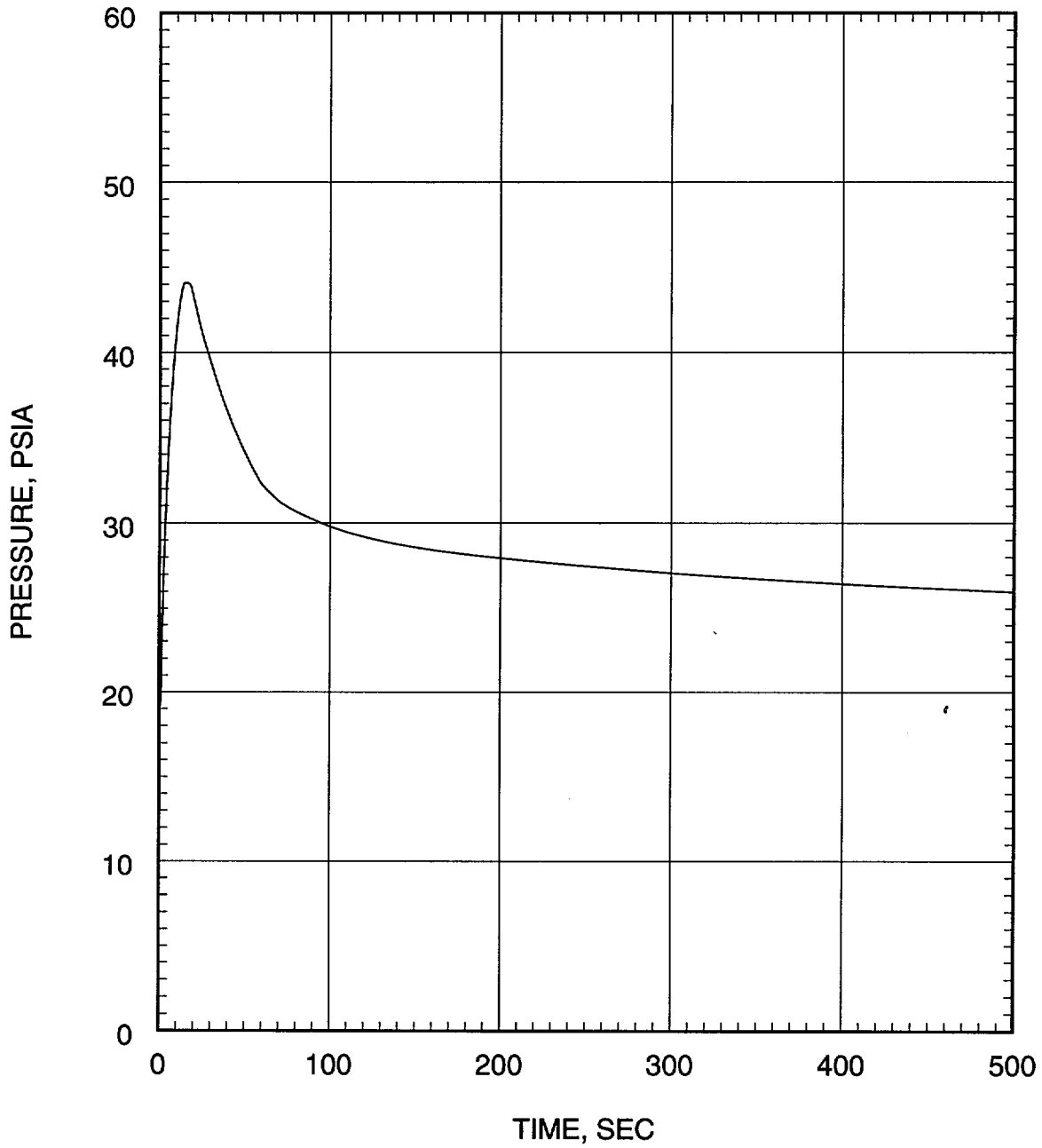


Figure 1.1-8

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Mass Added to Core During Reflood

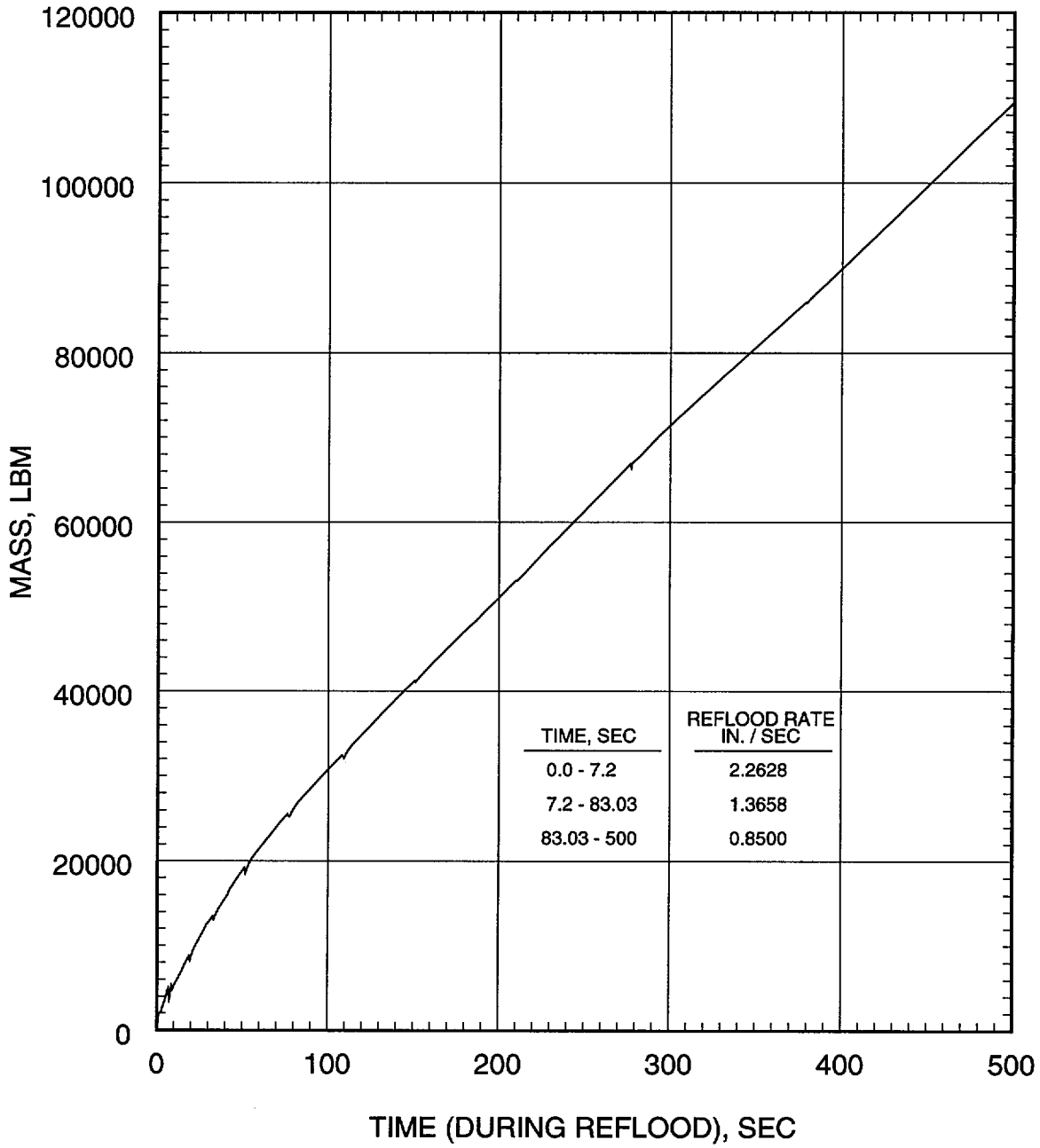


Figure 1.1-9

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Peak Cladding Temperature

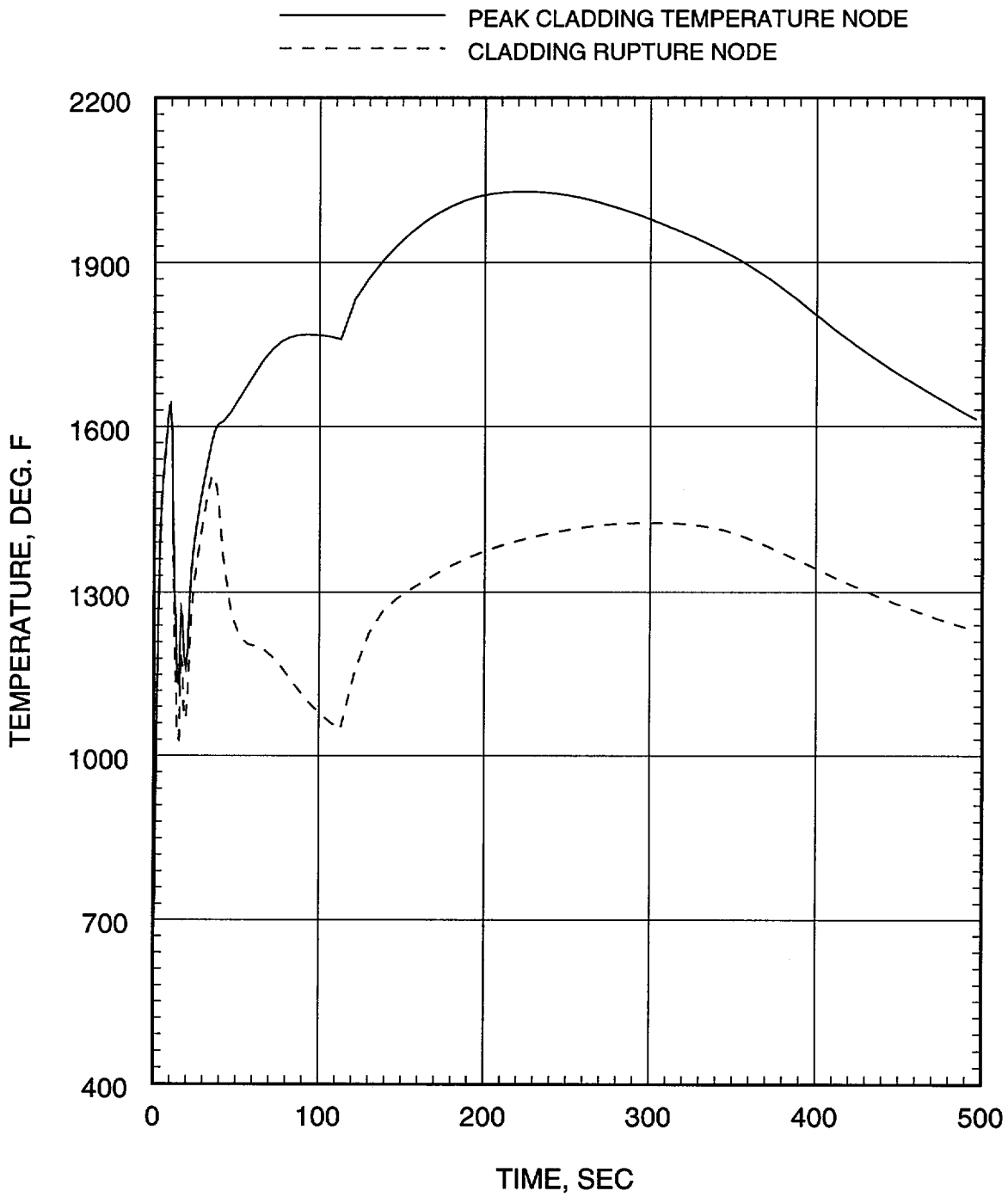


Figure 1.1-10

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Mid Annulus Flow Rate

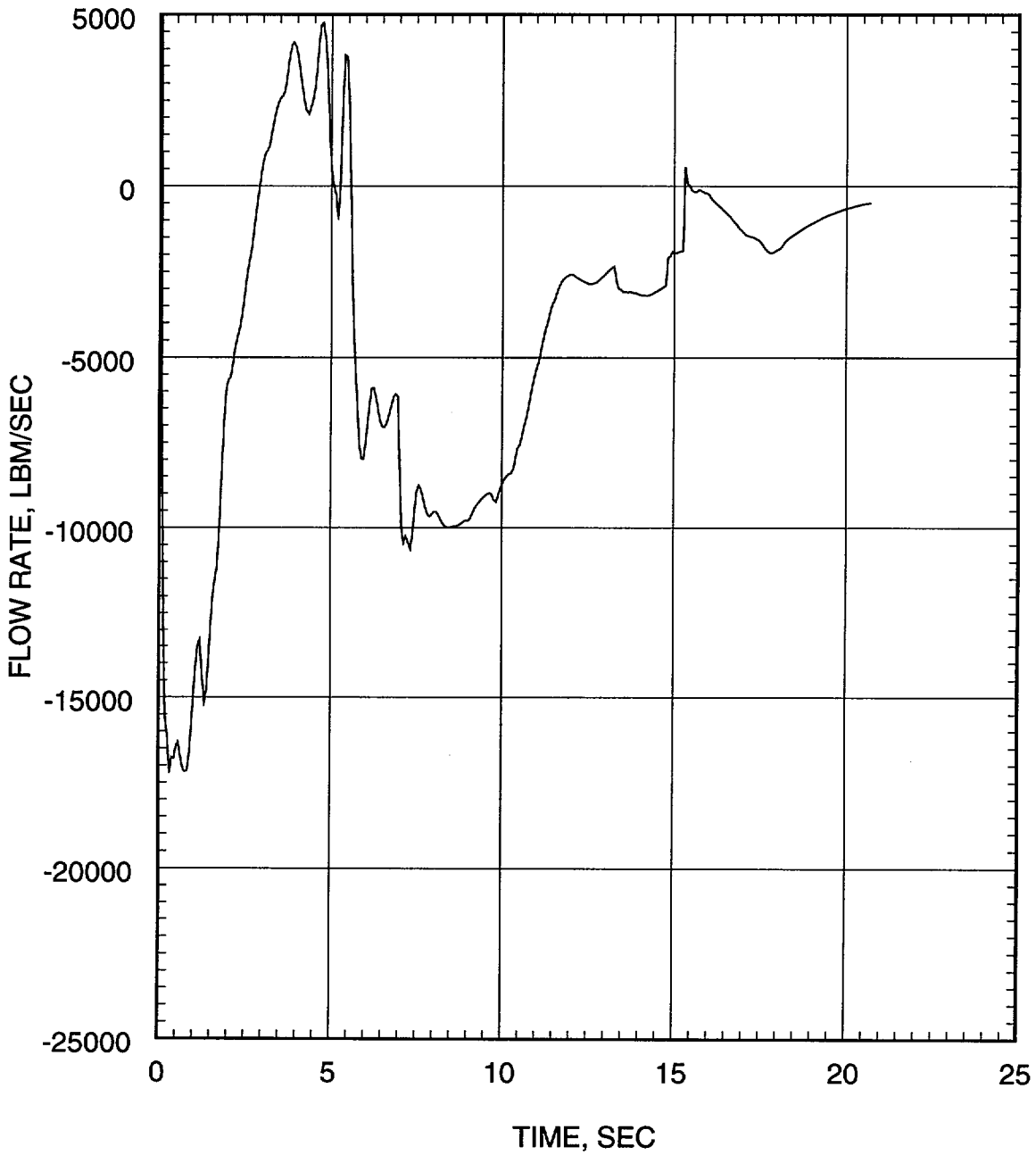


Figure 1.1-11

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Quality Above and Below the Core

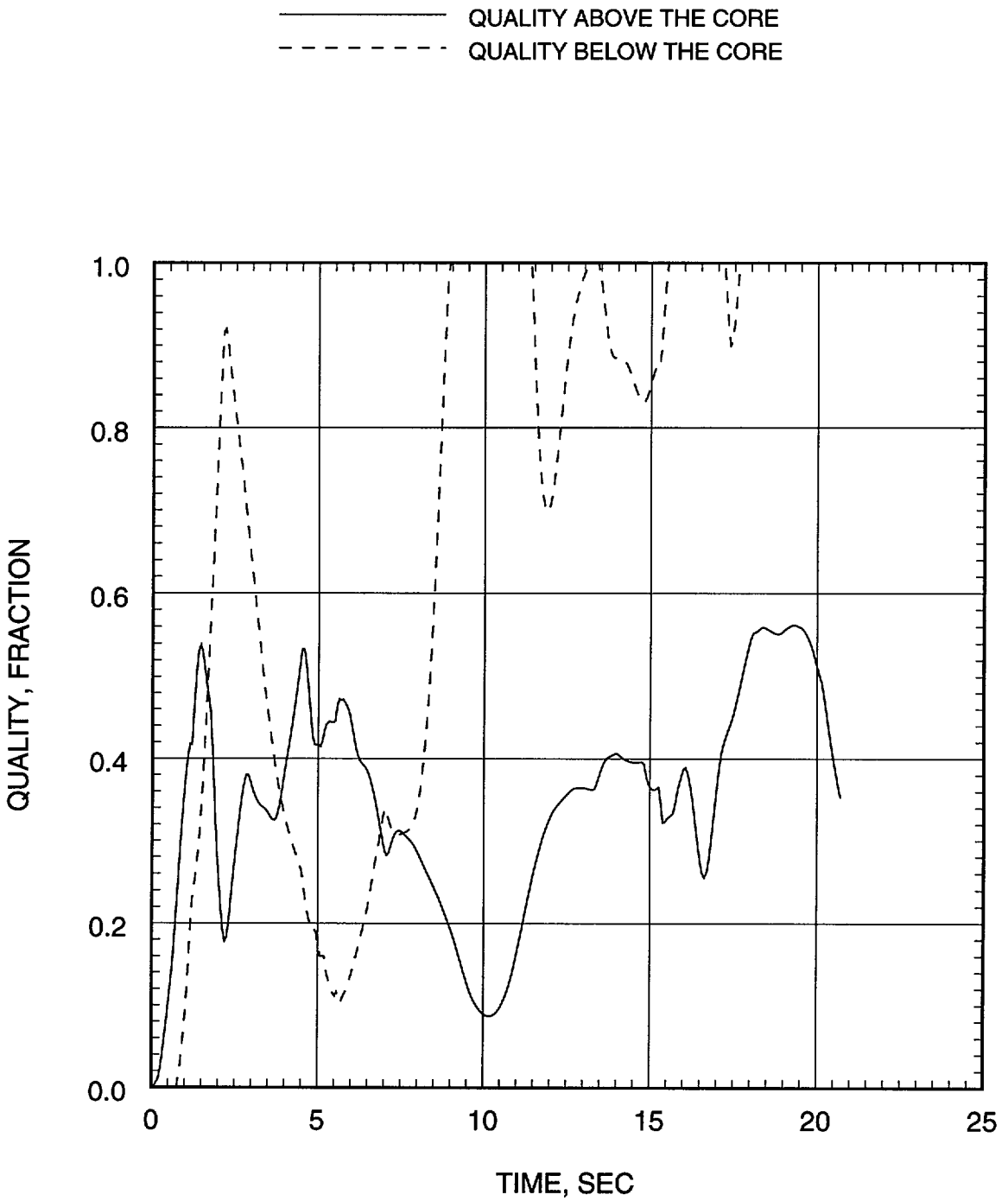


Figure 1.1-12

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Core Pressure Drop

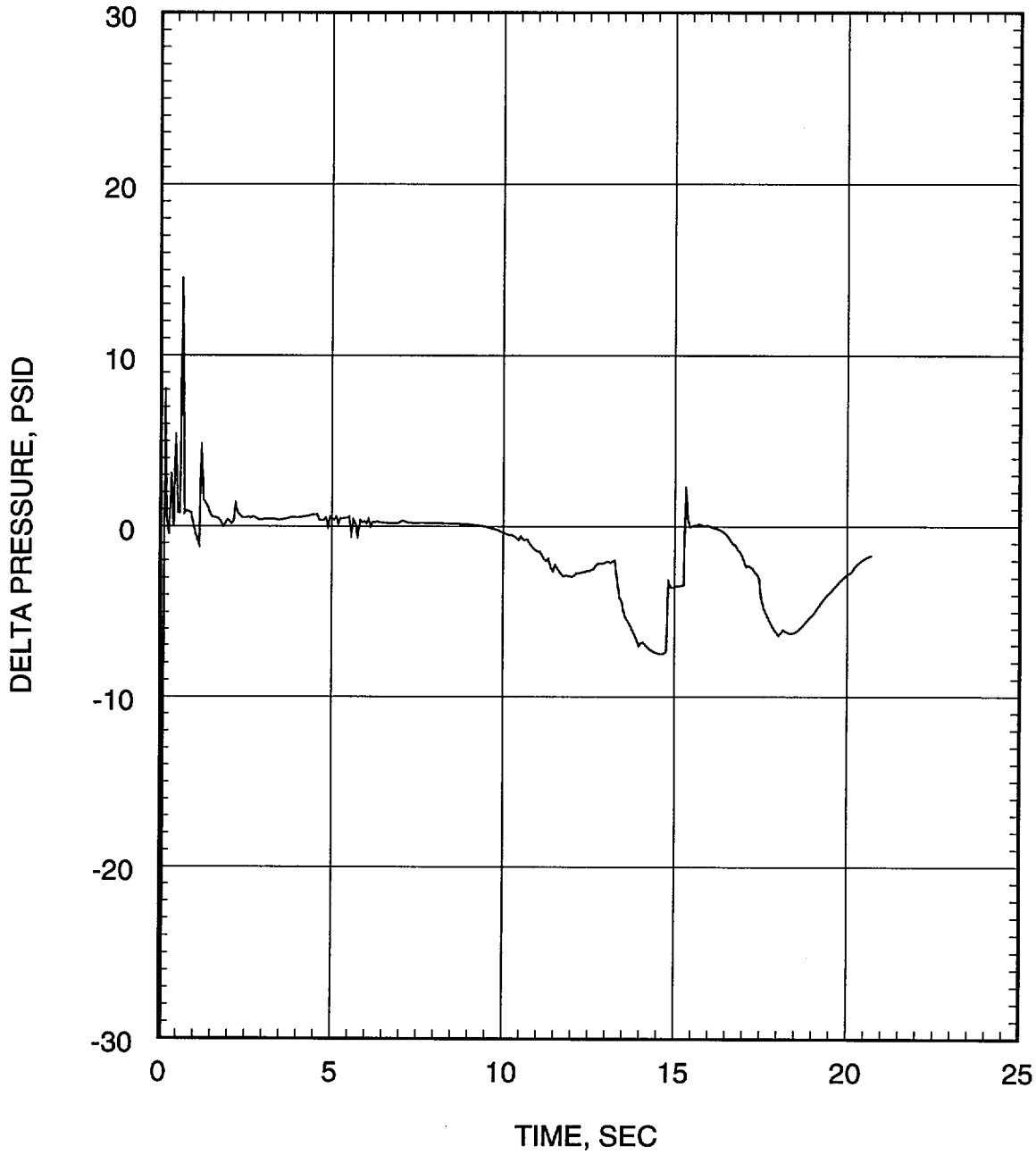


Figure 1.1-13

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Safety Injection Flow Rate into Intact Discharge Legs

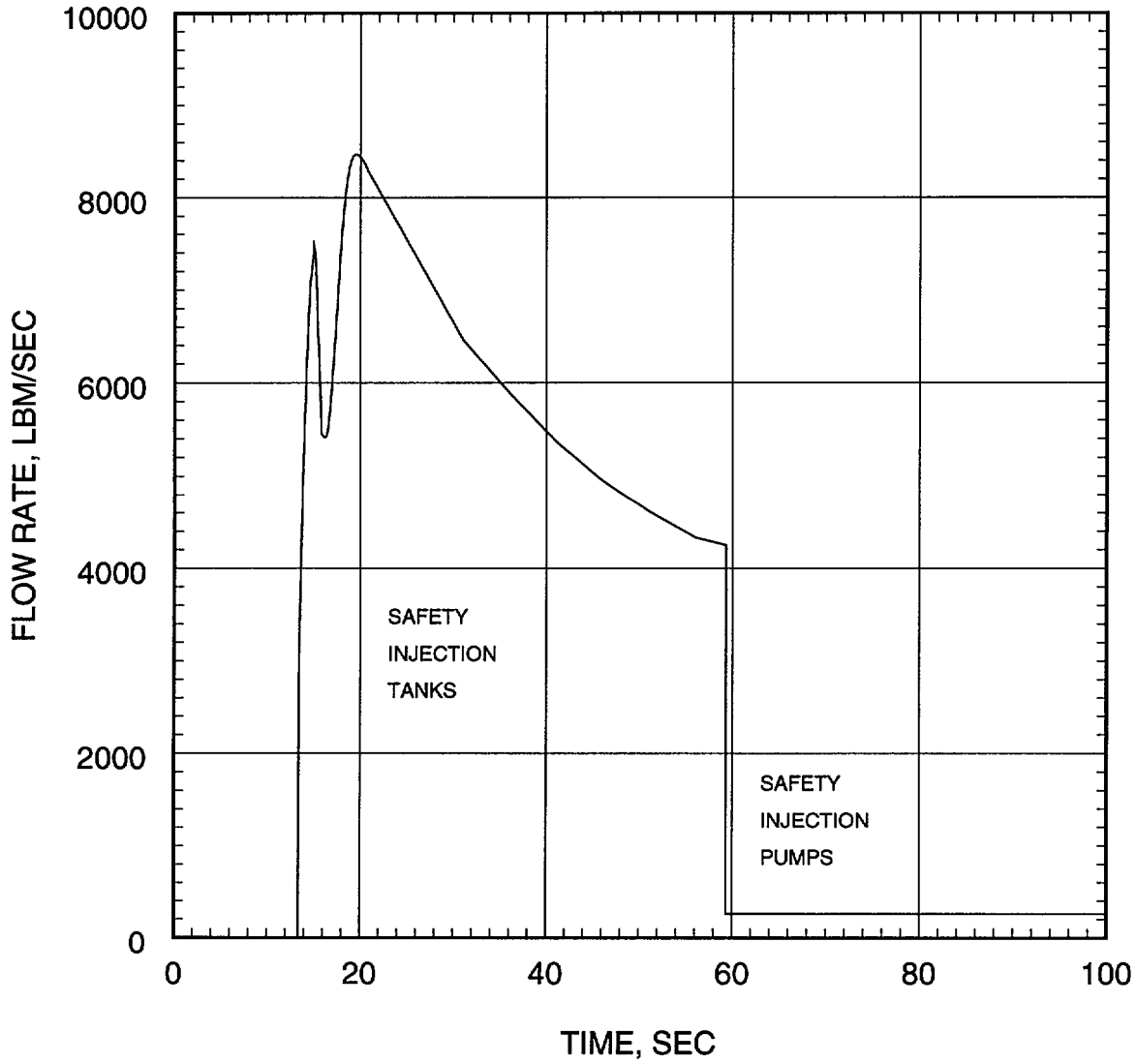


Figure 1.1-14

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Water Level in Downcomer During Reflood

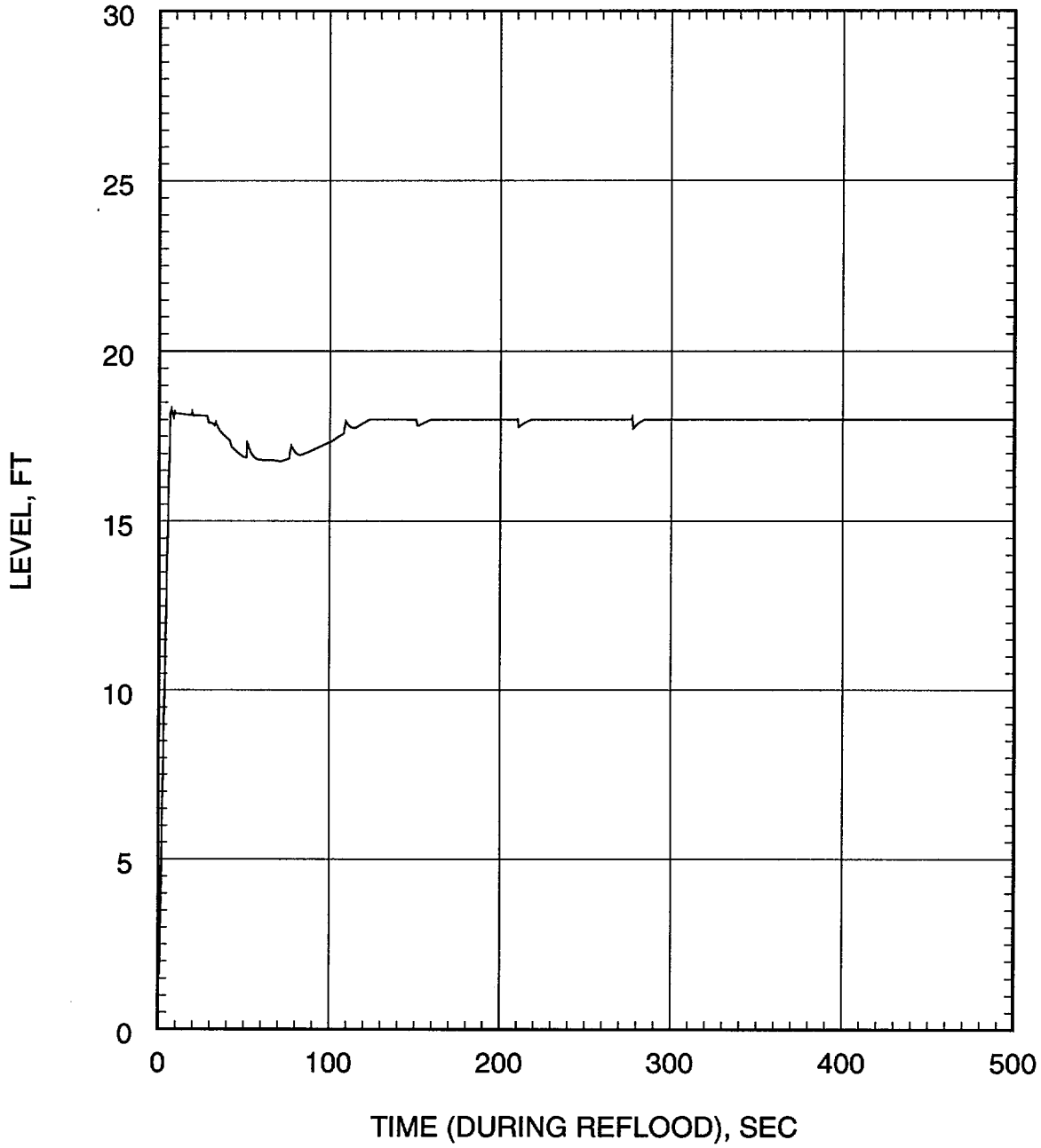


Figure 1.1-15

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Hot Spot Gap Conductance

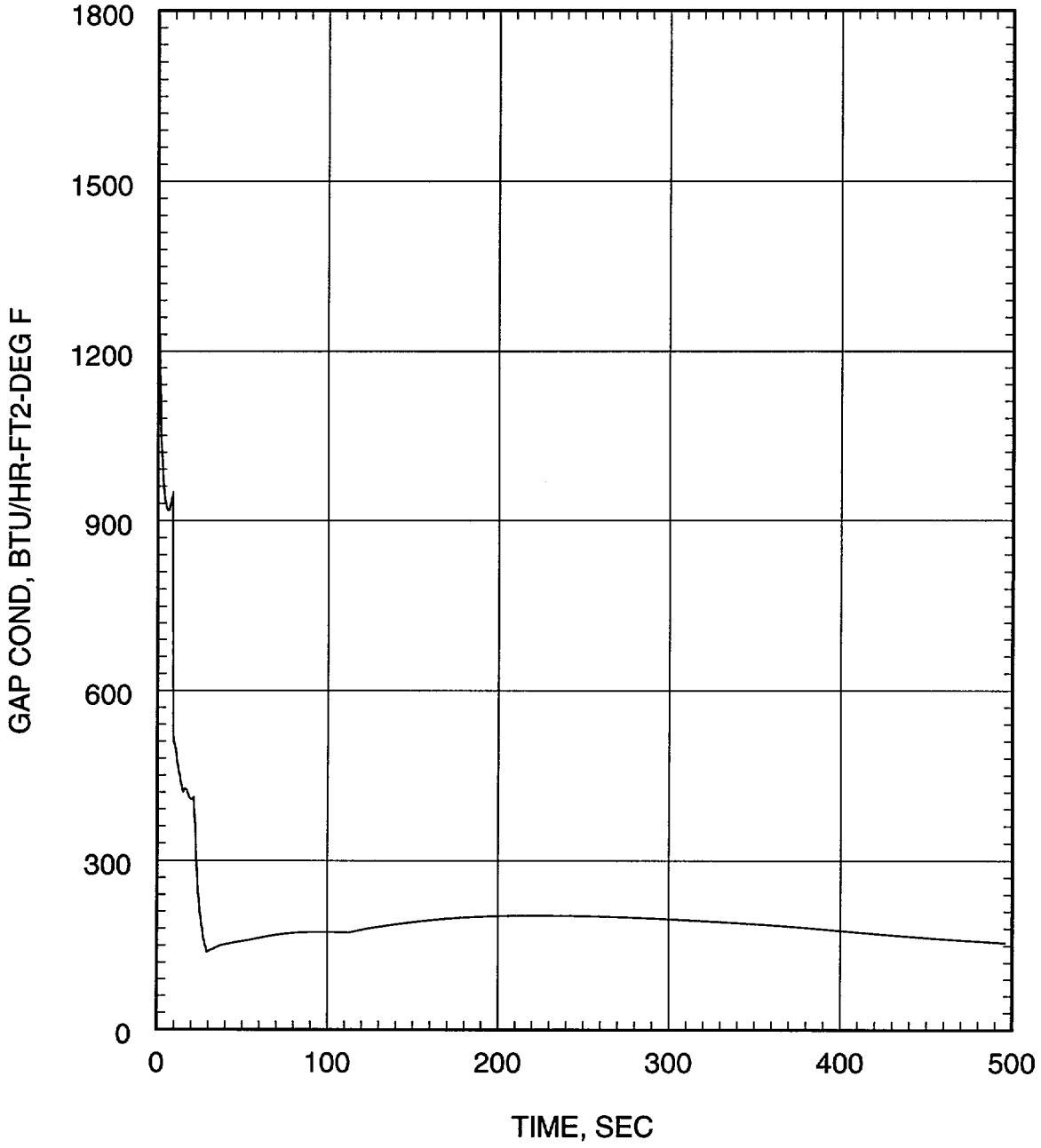


Figure 1.1-16

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Local Cladding Oxidation Percentage

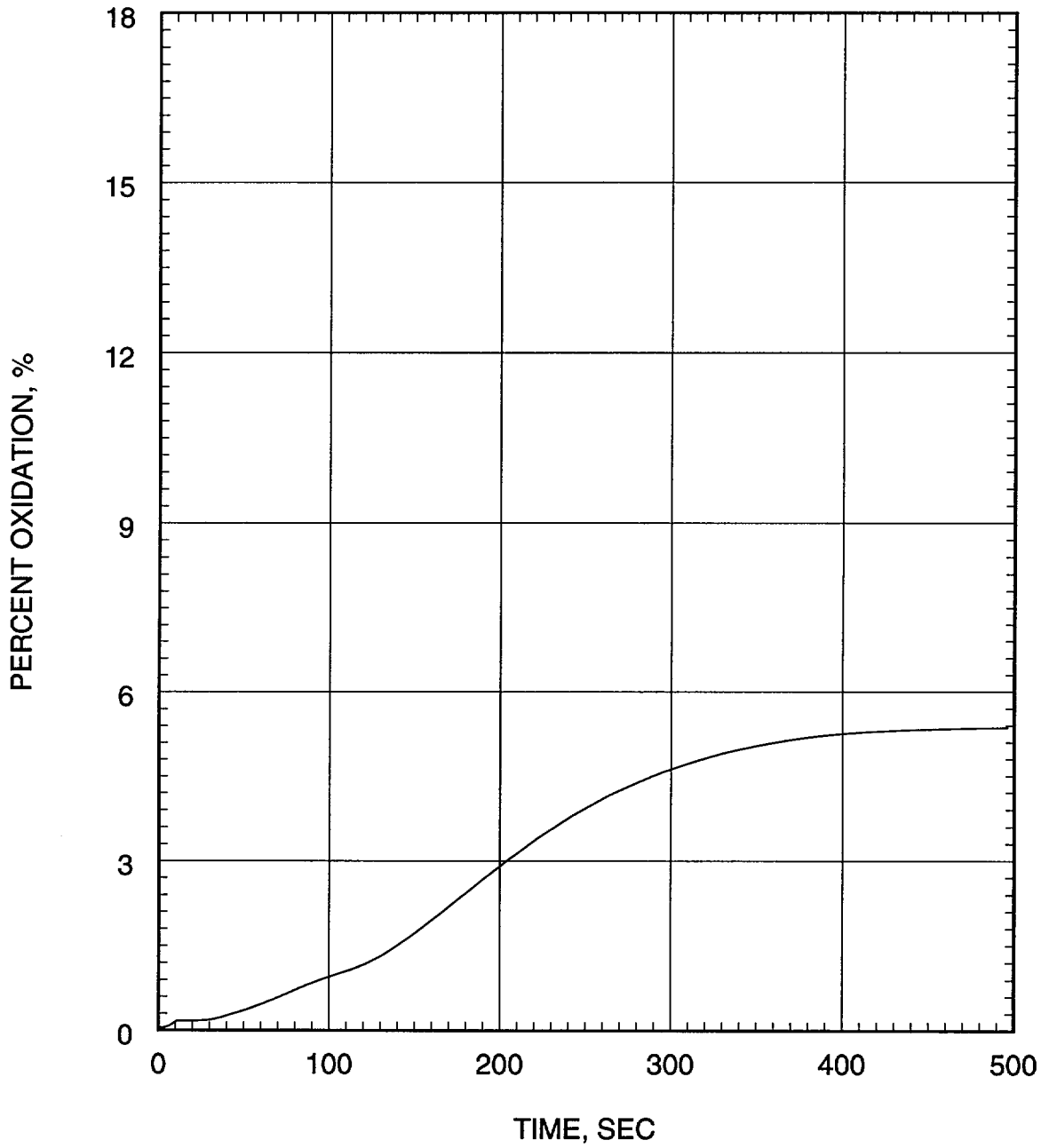


Figure 1.1-17

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Fuel Centerline, Fuel Average, Cladding, and Coolant Temperature at the Hot Spot

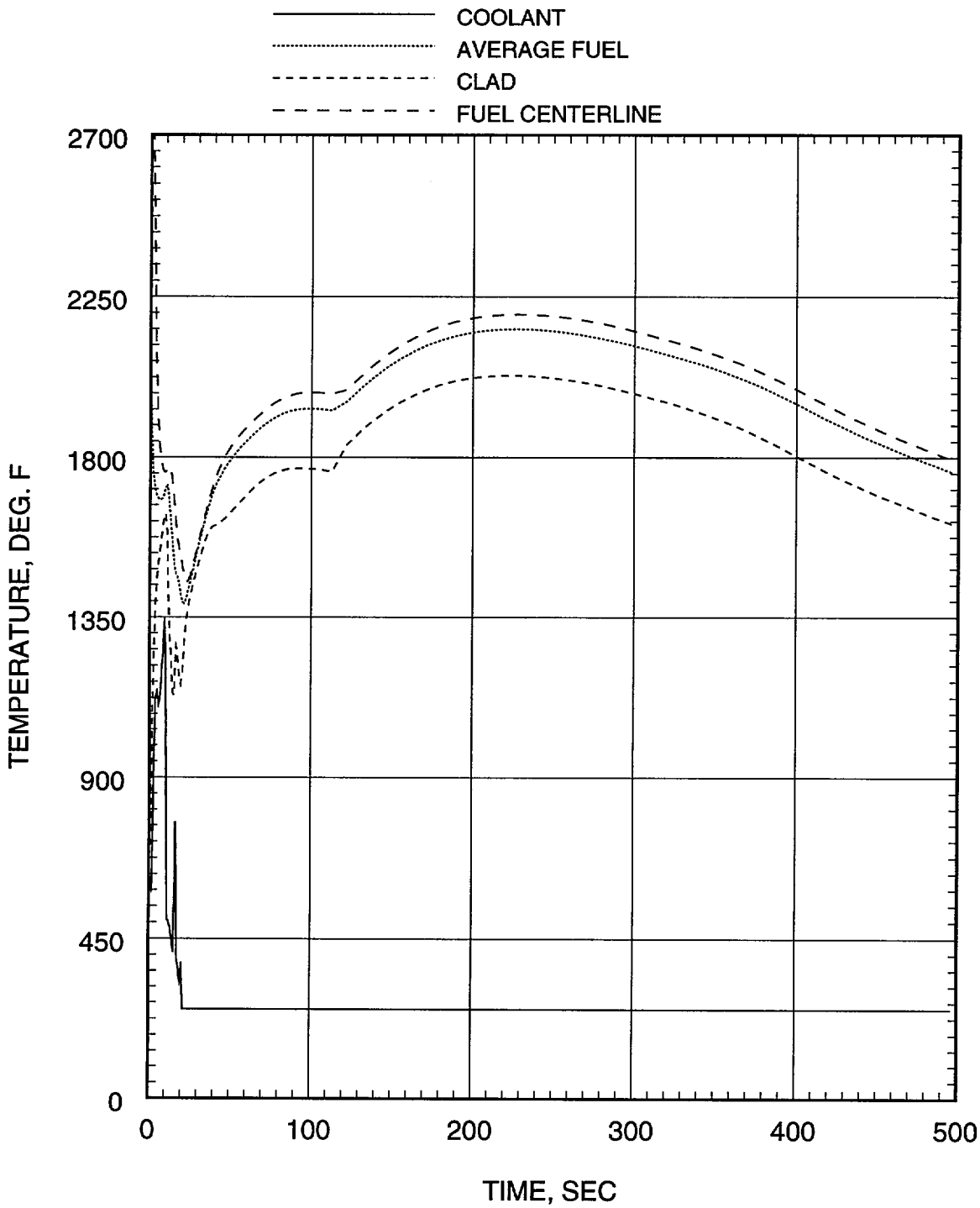


Figure 1.1-18

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Hot Spot Heat Transfer Coefficient

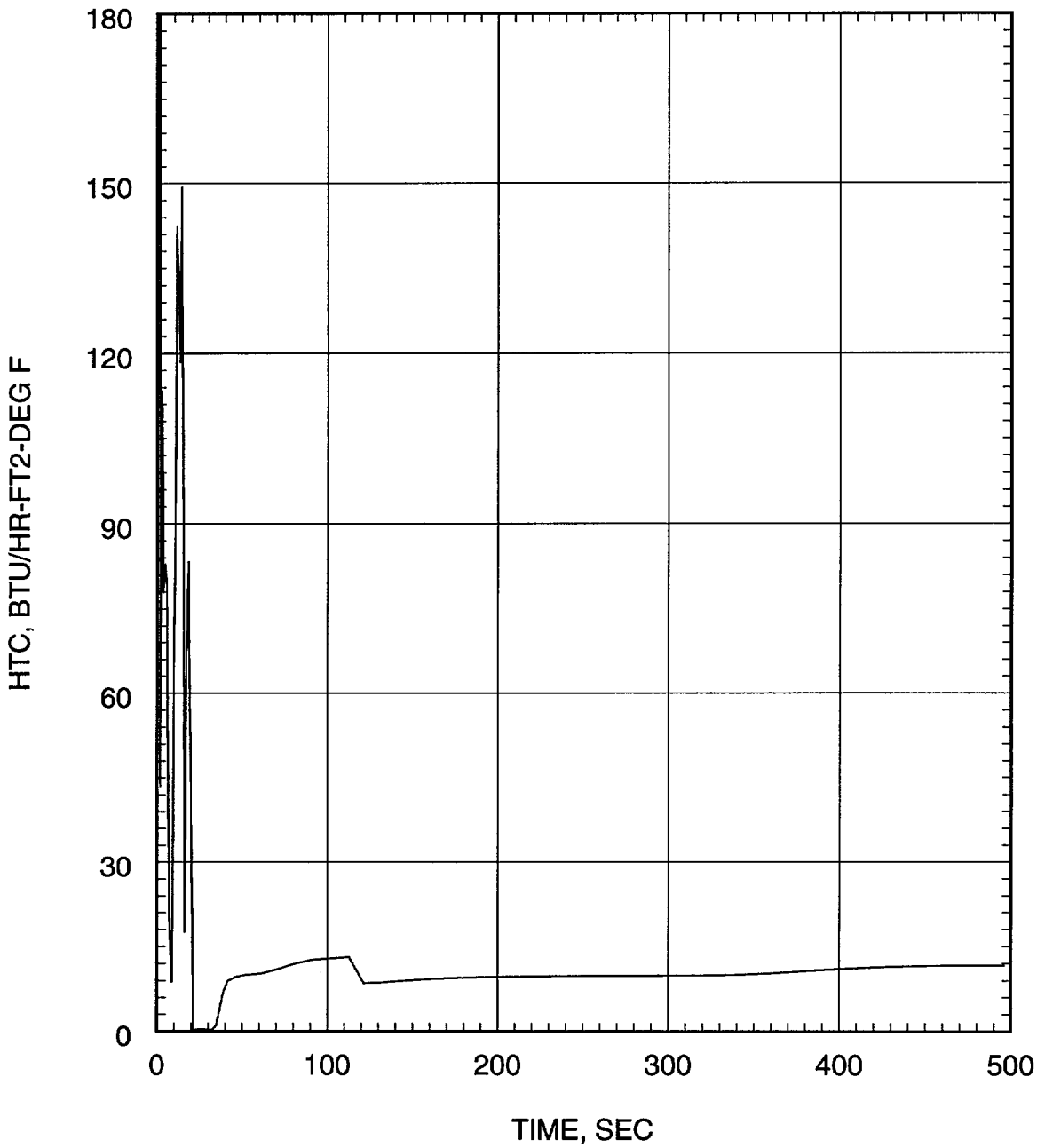


Figure 1.1-19

ANO-2 RSG Large Break LOCA ECCS Performance Analysis
0.6 DEG/PD Break
Hot Pin Pressure

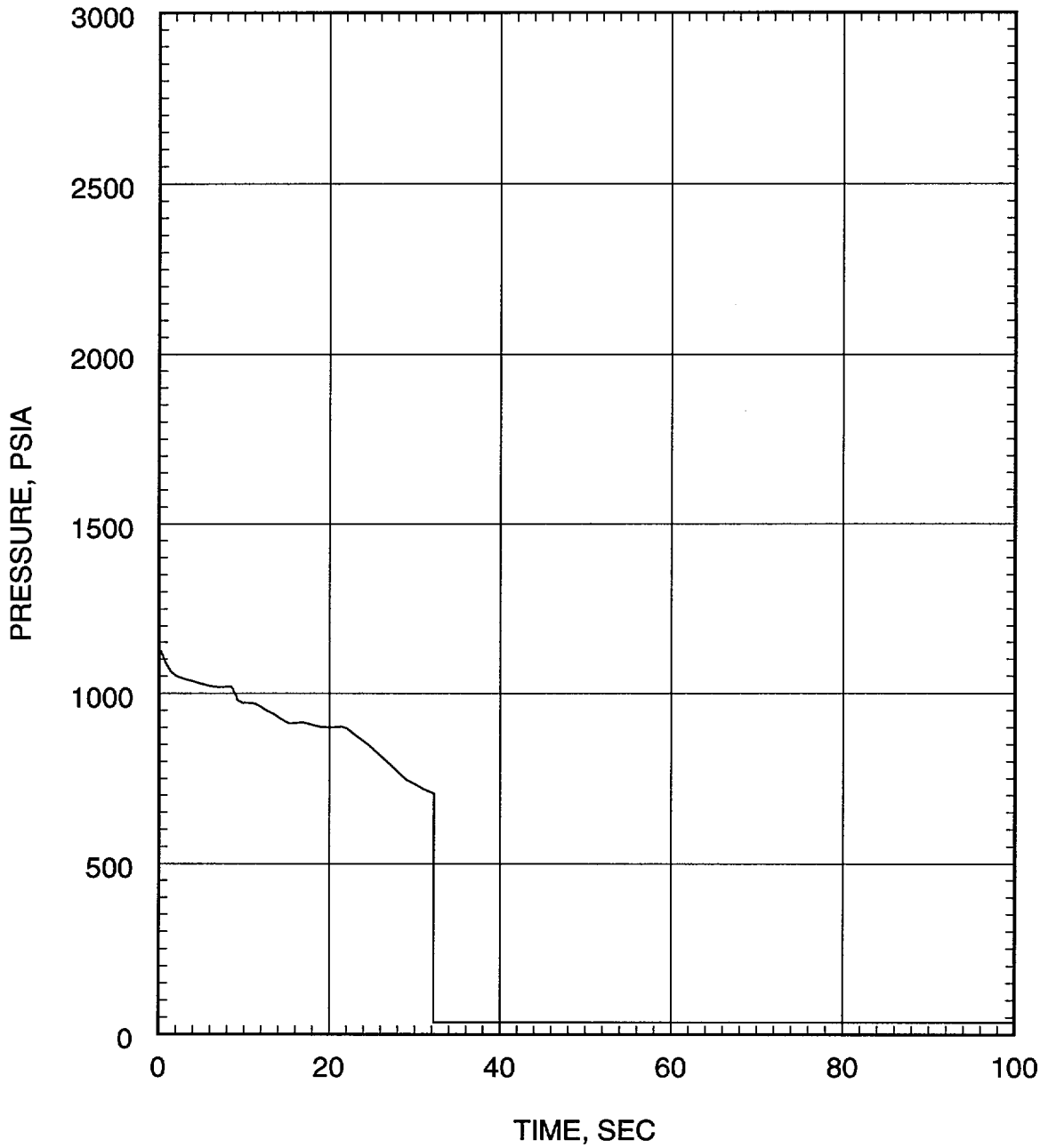


Figure 1.2-1

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft^2/PD Break
Core Power

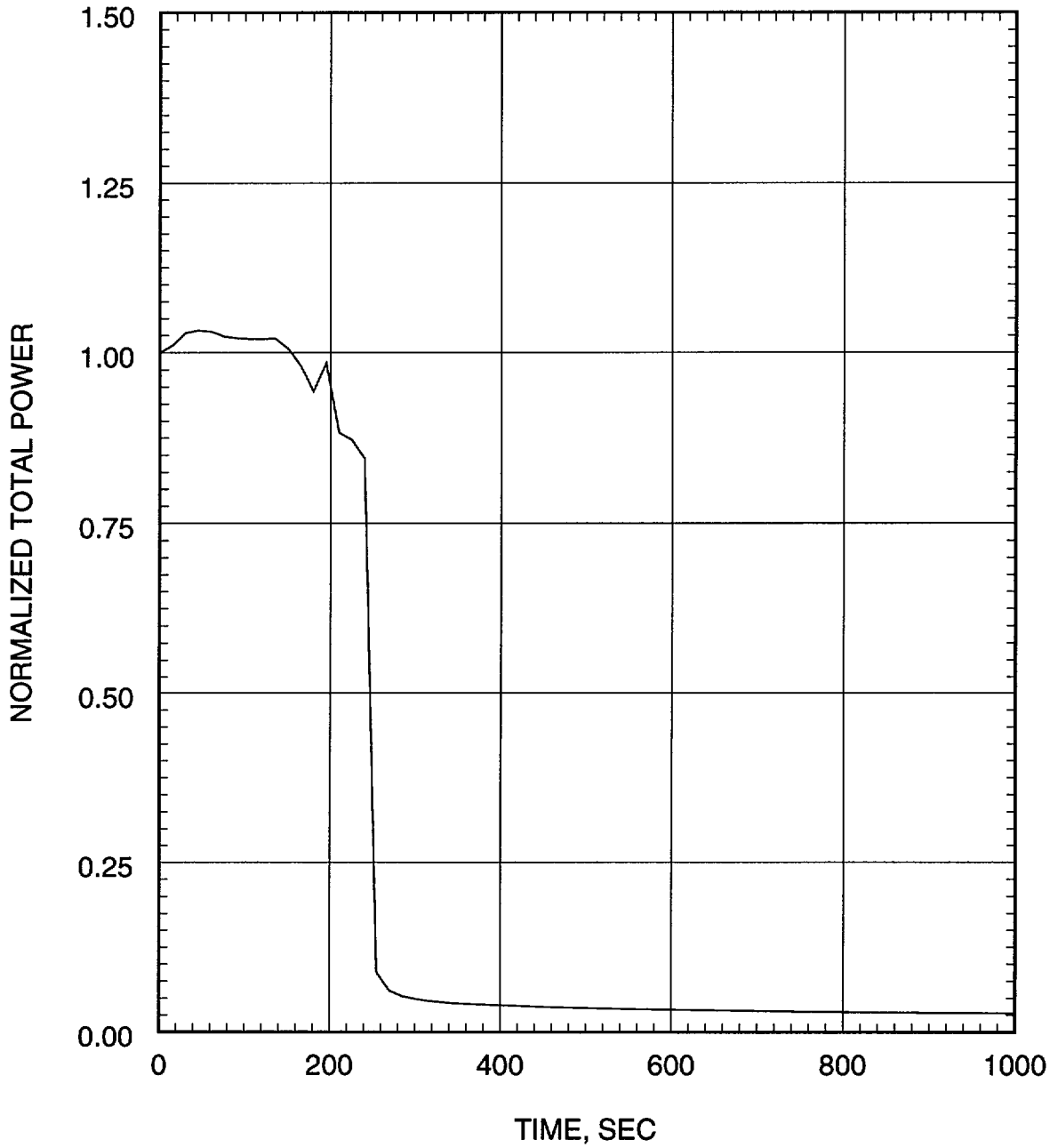


Figure 1.2-2

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft^2/PD Break
Inner Vessel Pressure

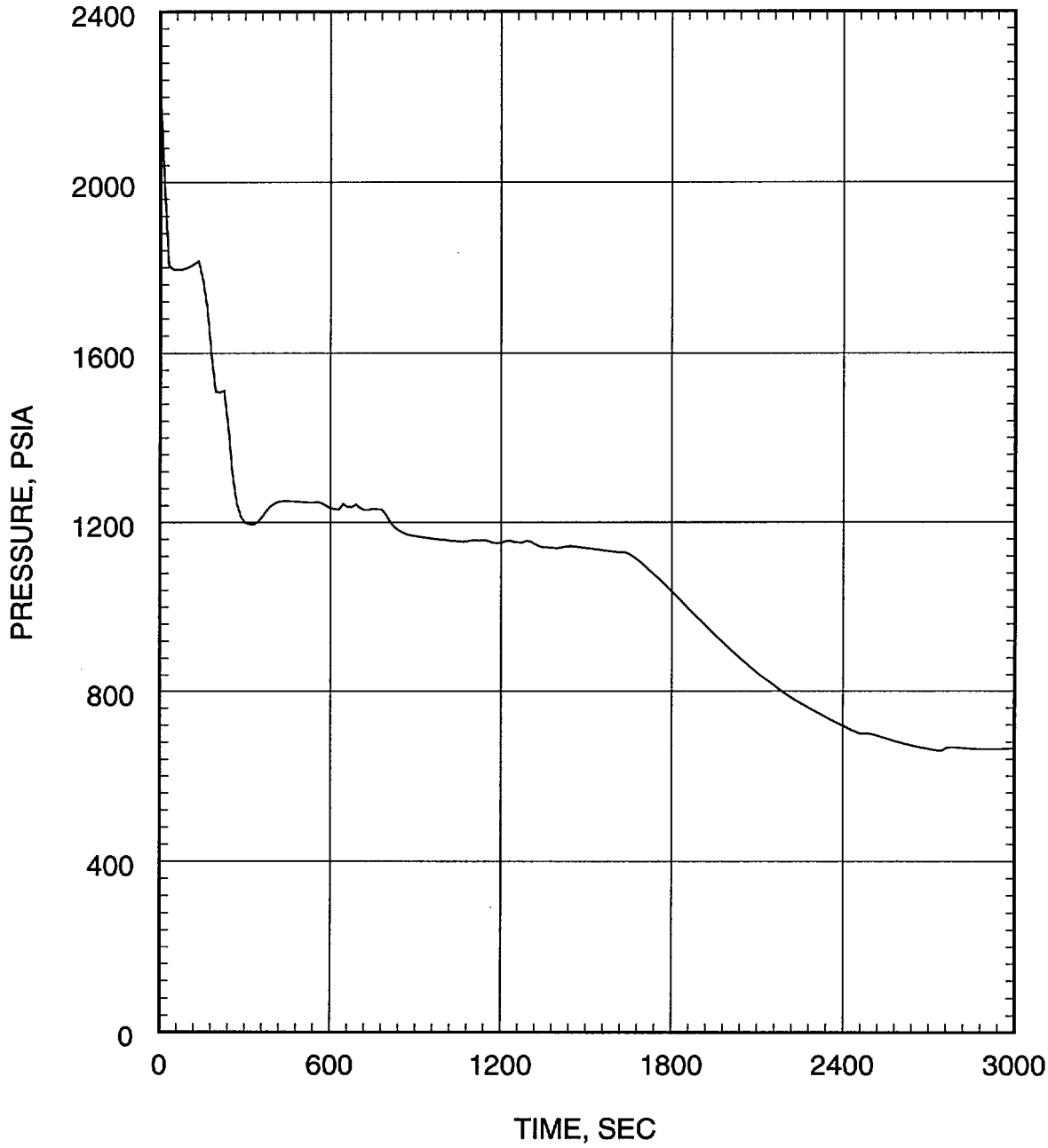


Figure 1.2-3

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft^2/PD Break
Break Flow Rate

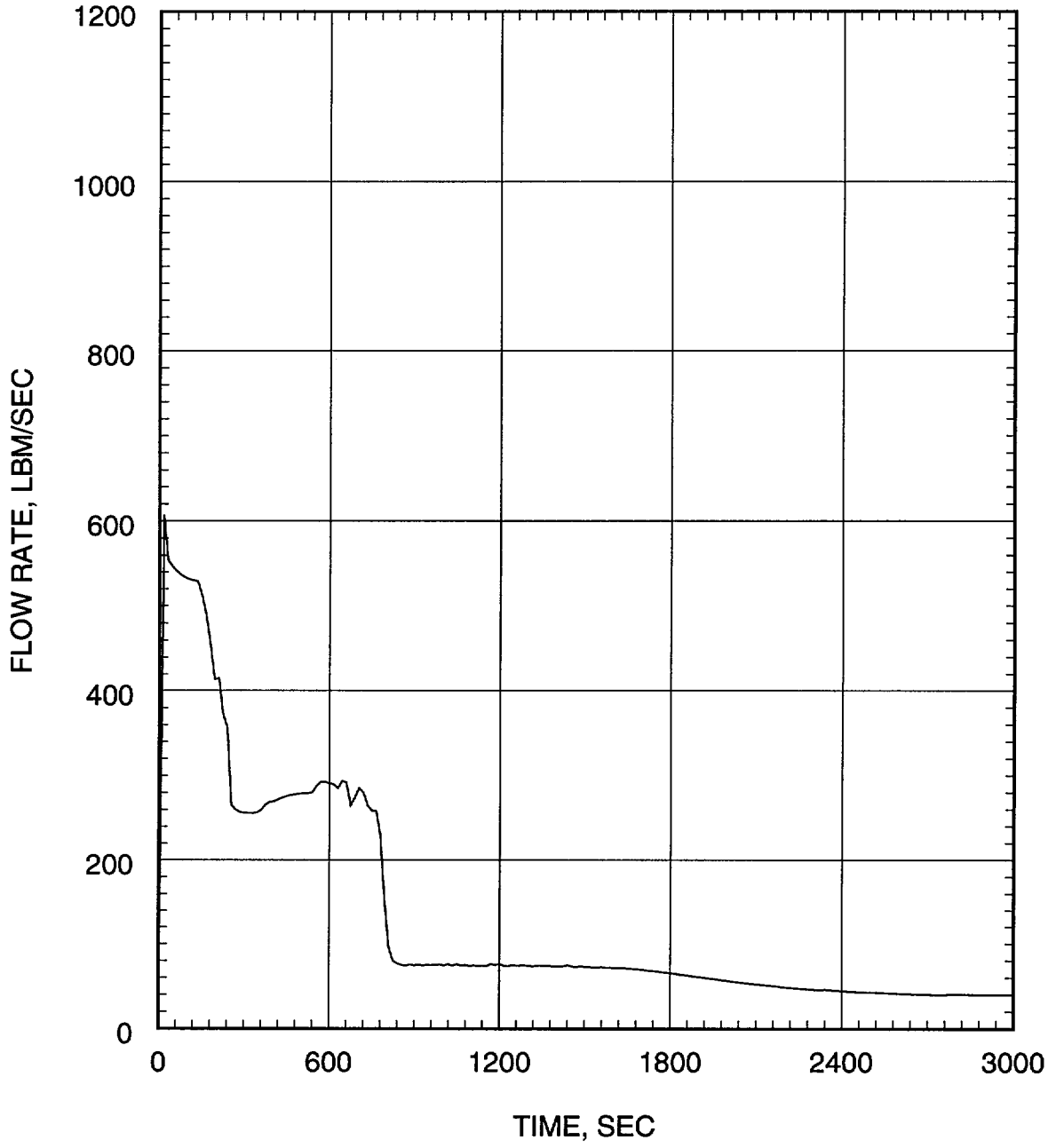


Figure 1.2-4

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft^2/PD Break
Inner Vessel Inlet Flow Rate

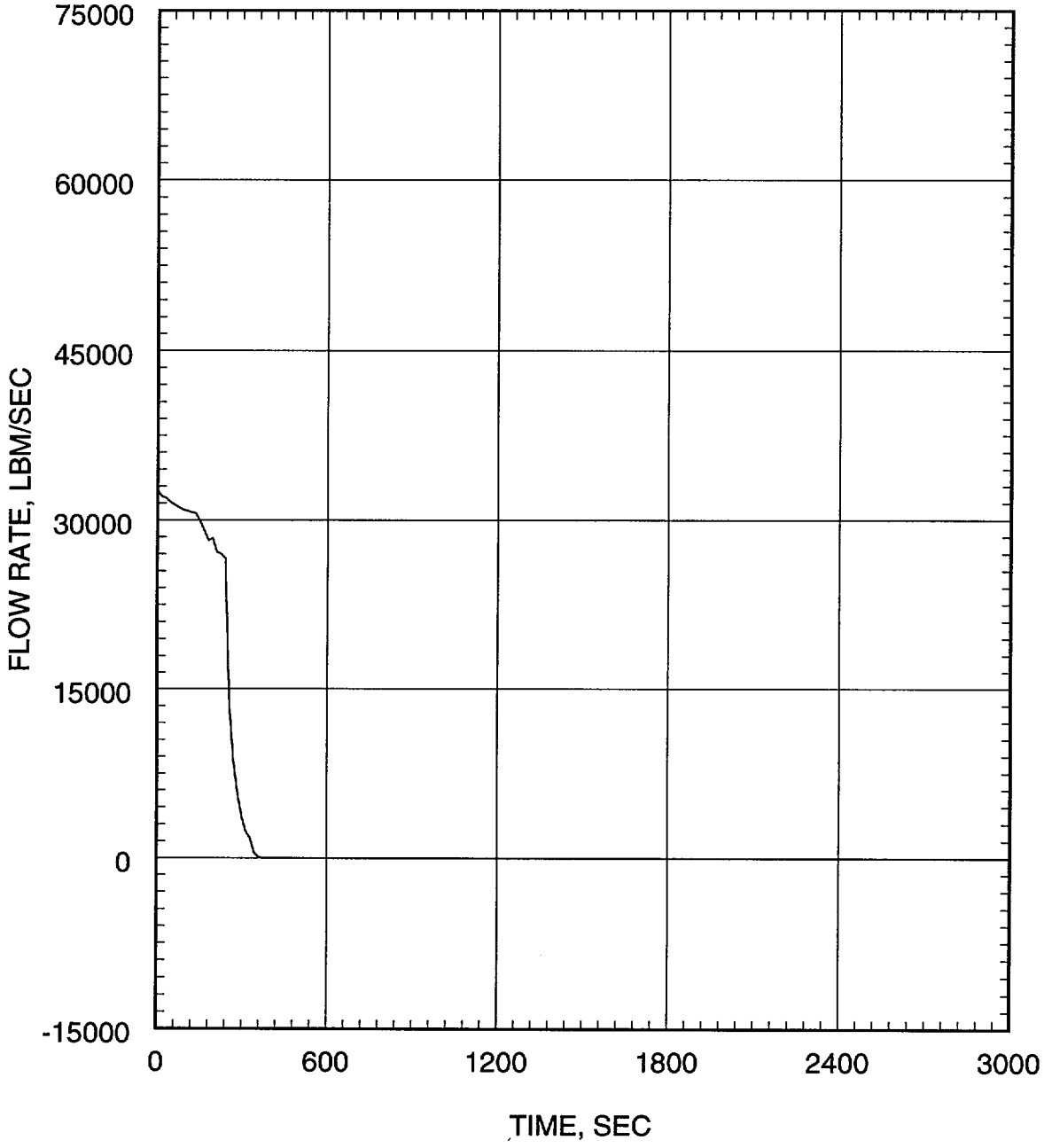


Figure 1.2-5

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft²/PD Break
Inner Vessel Two-Phase Mixture Level

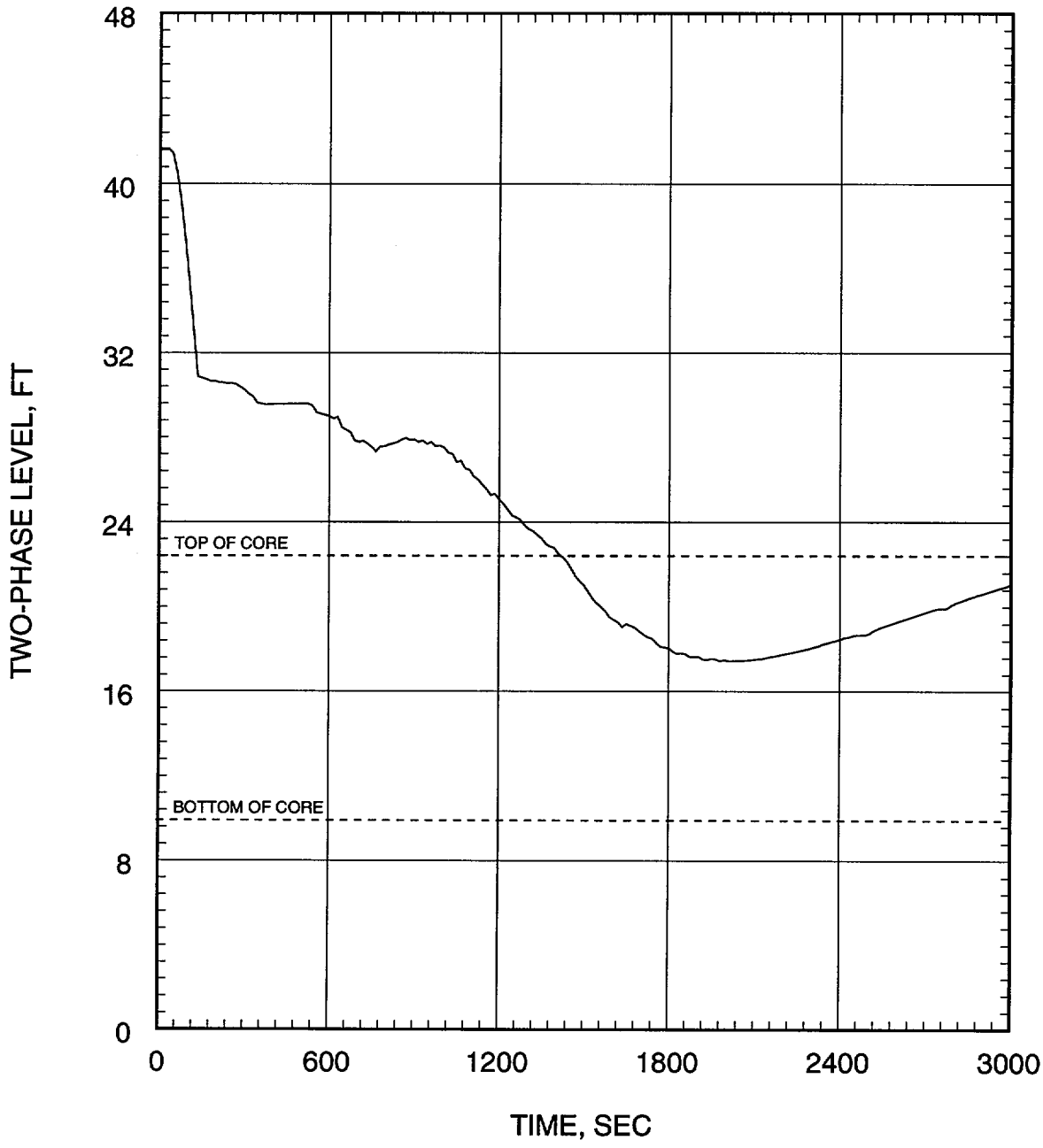


Figure 1.2-6

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

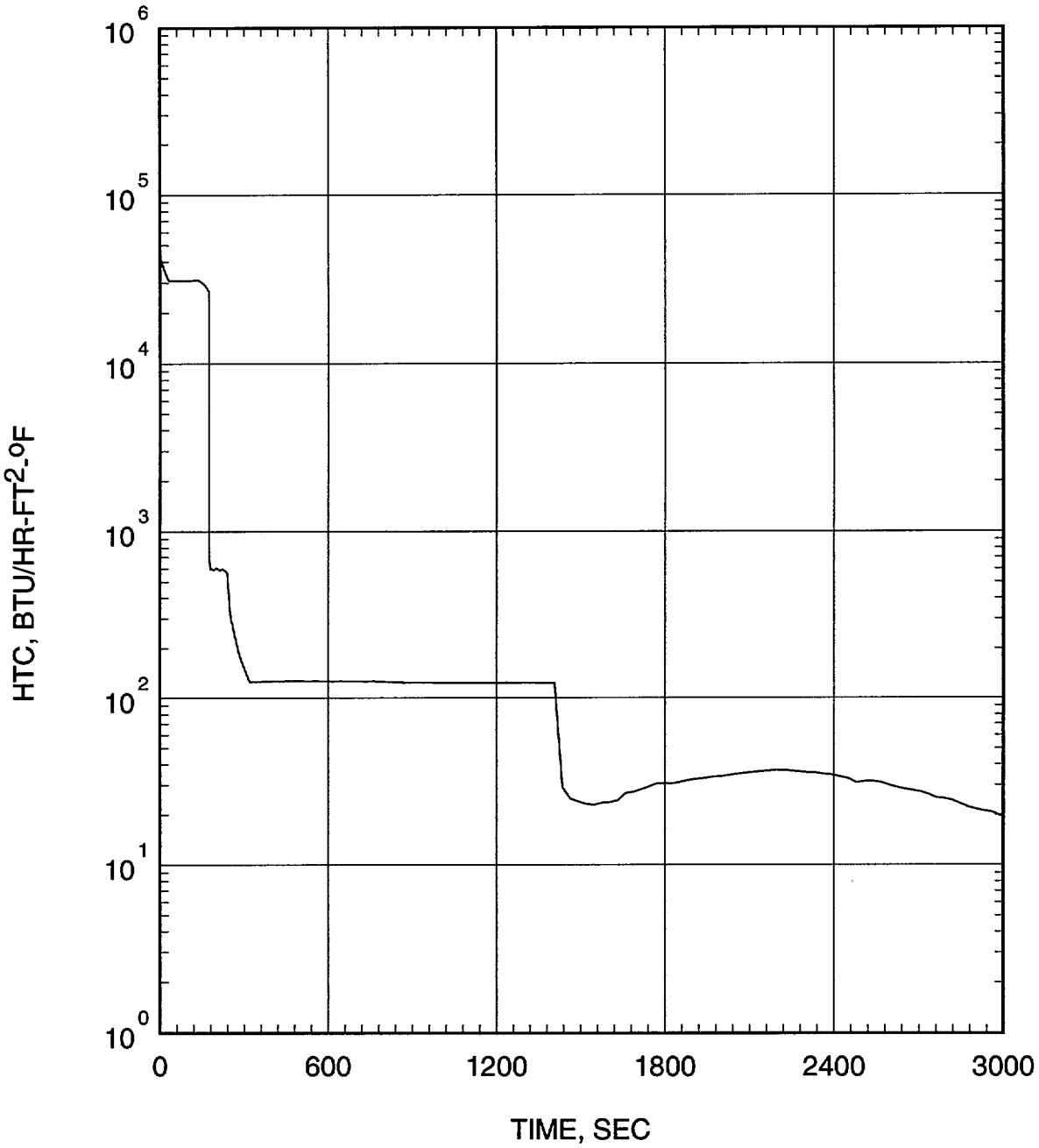


Figure 1.2-7

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft^2/PD Break
Coolant Temperature at Hot Spot

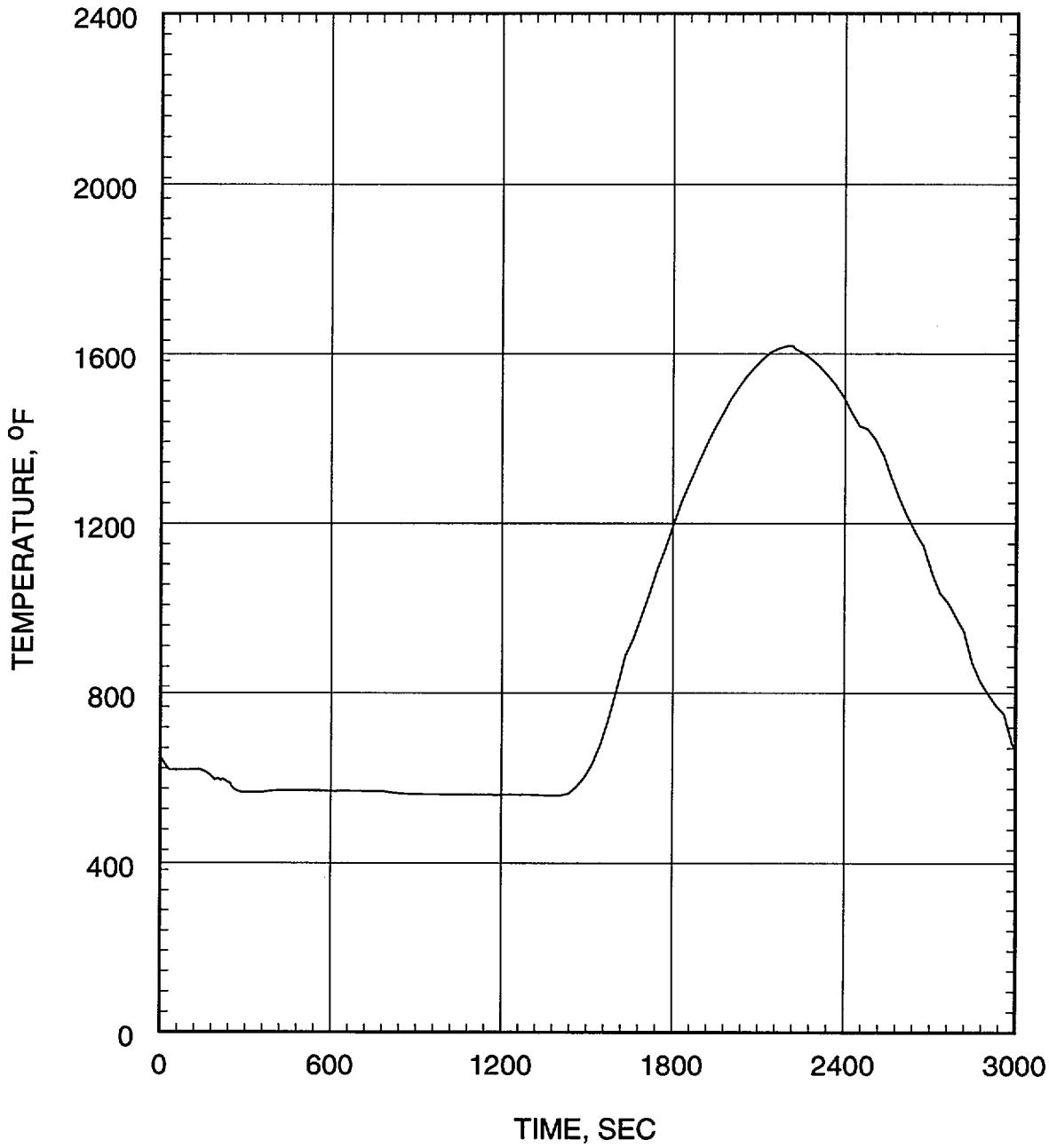


Figure 1.2-8

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.03 ft^2/PD Break
Cladding Temperature at Hot Spot

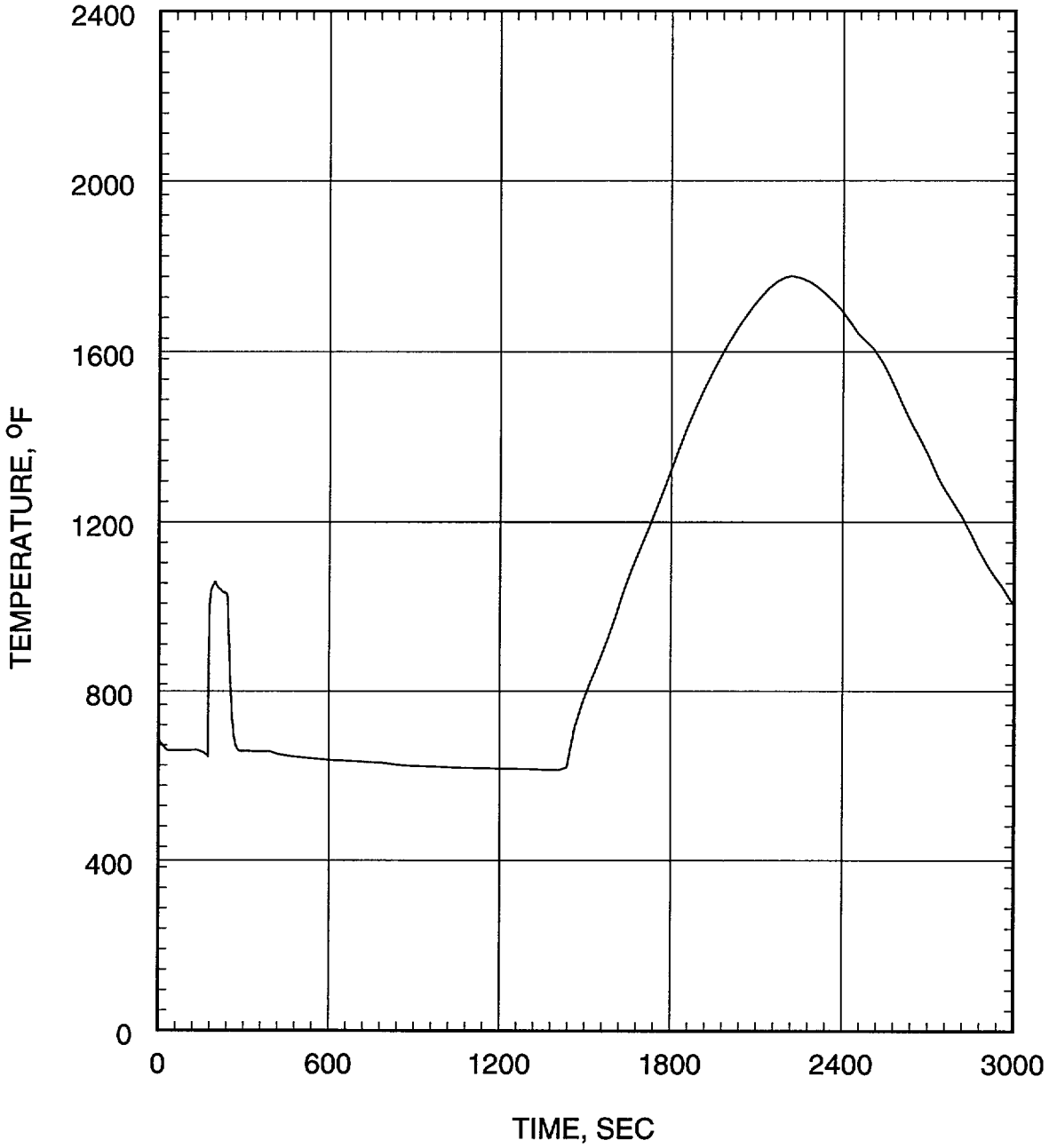


Figure 1.2-9

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Core Power

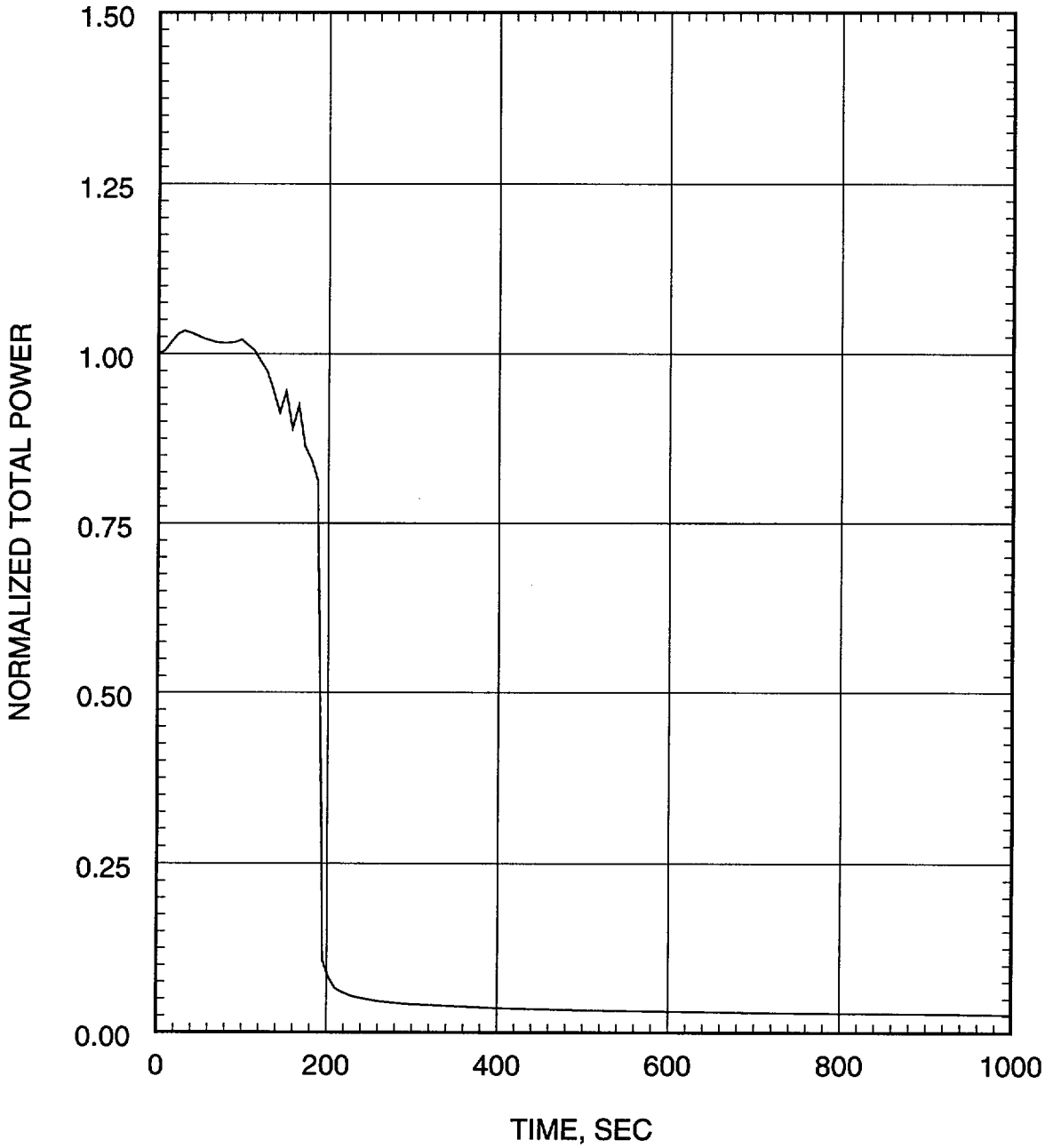


Figure 1.2-10

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Inner Vessel Pressure

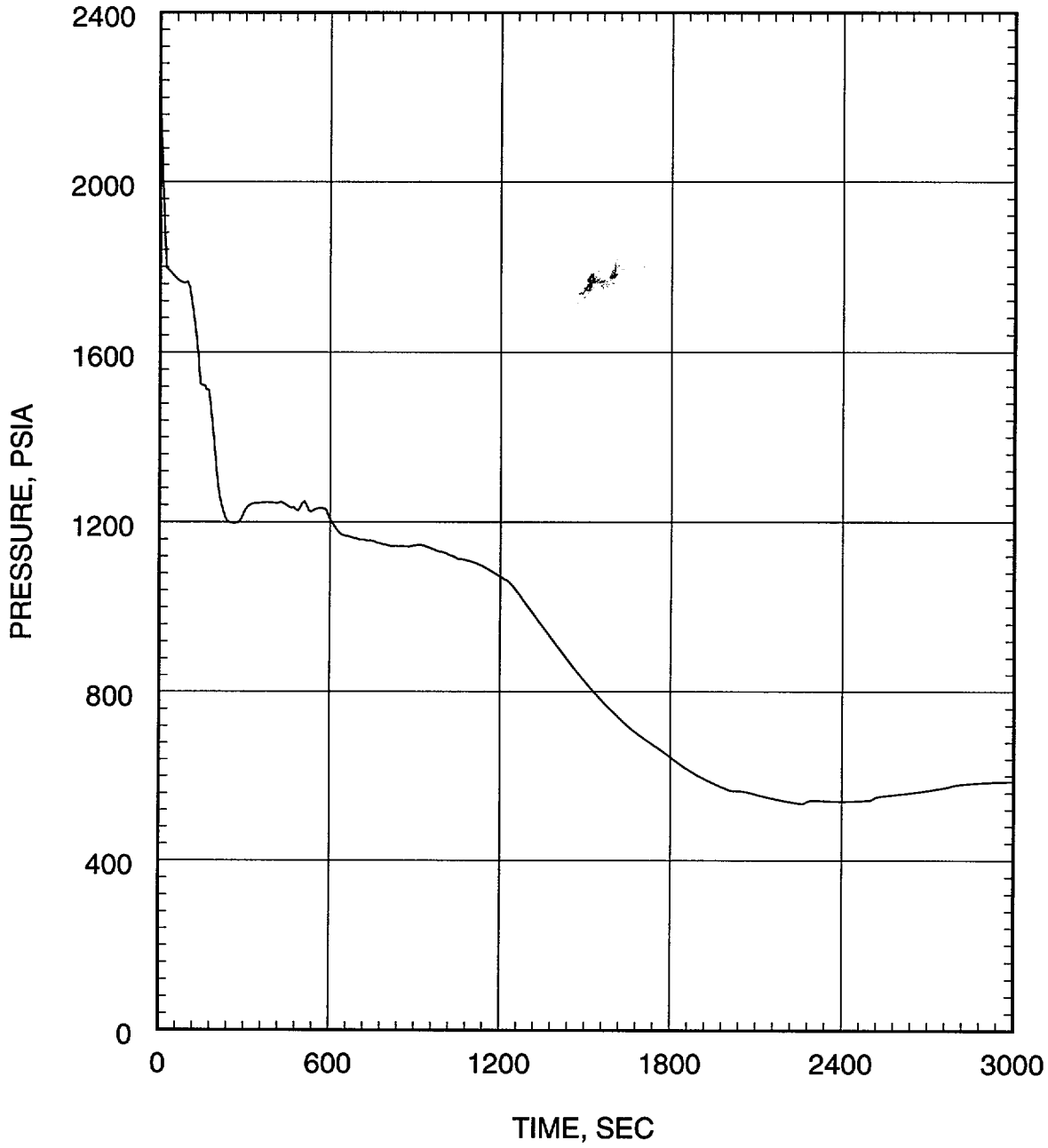


Figure 1.2-11

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Break Flow Rate

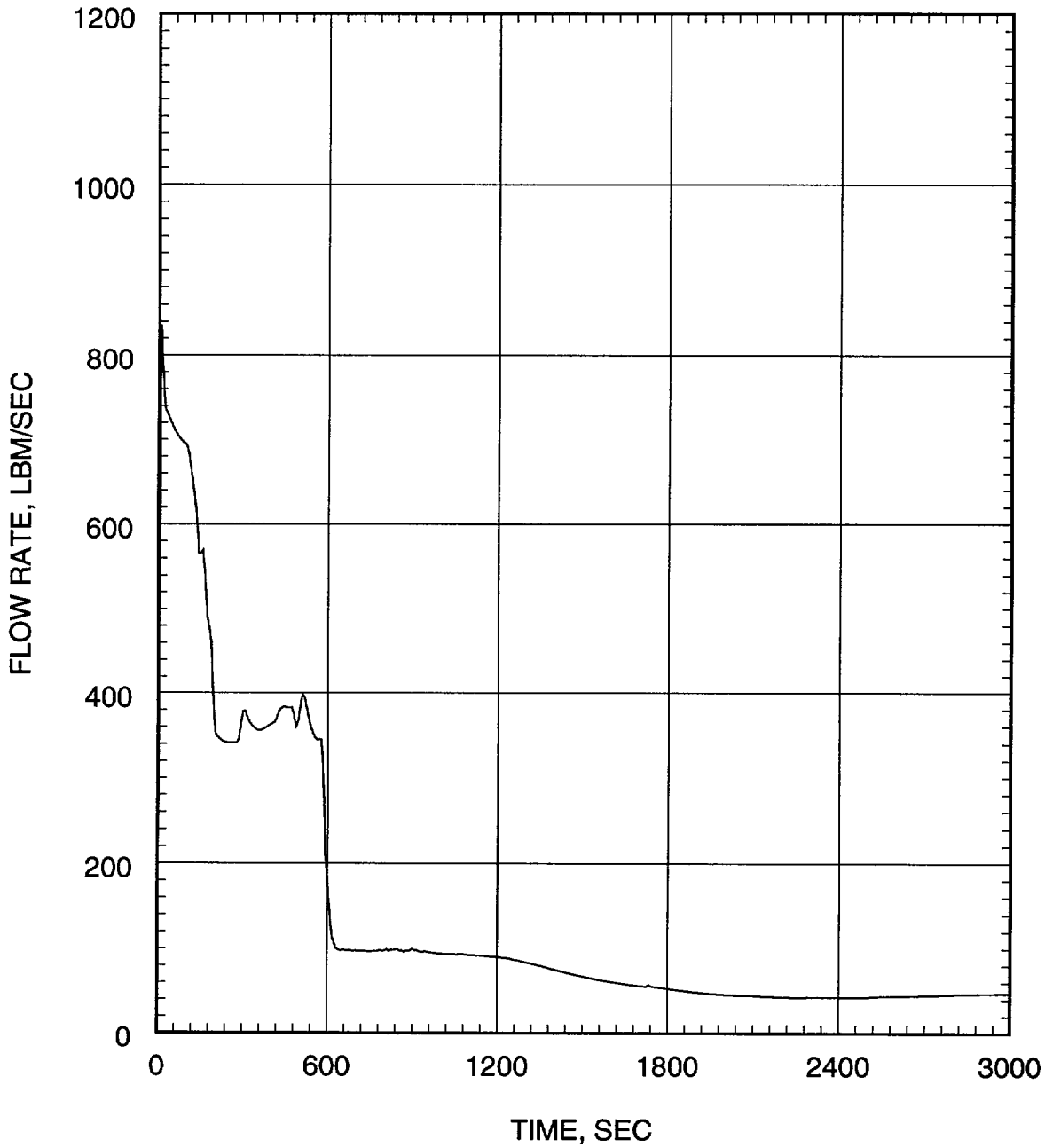


Figure 1.2-12

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Inner Vessel Inlet Flow Rate

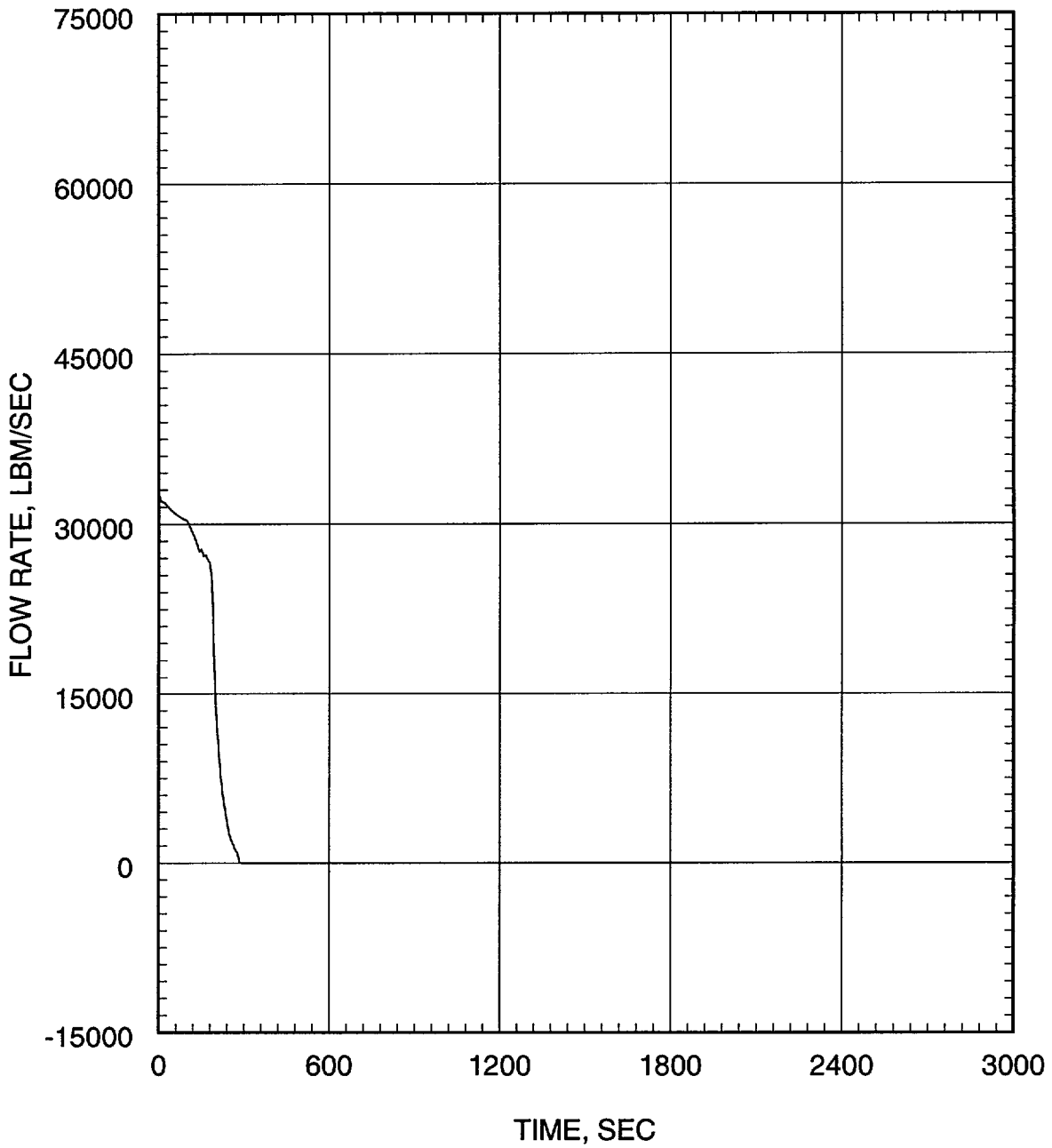


Figure 1.2-13

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Inner Vessel Two-Phase Mixture Level

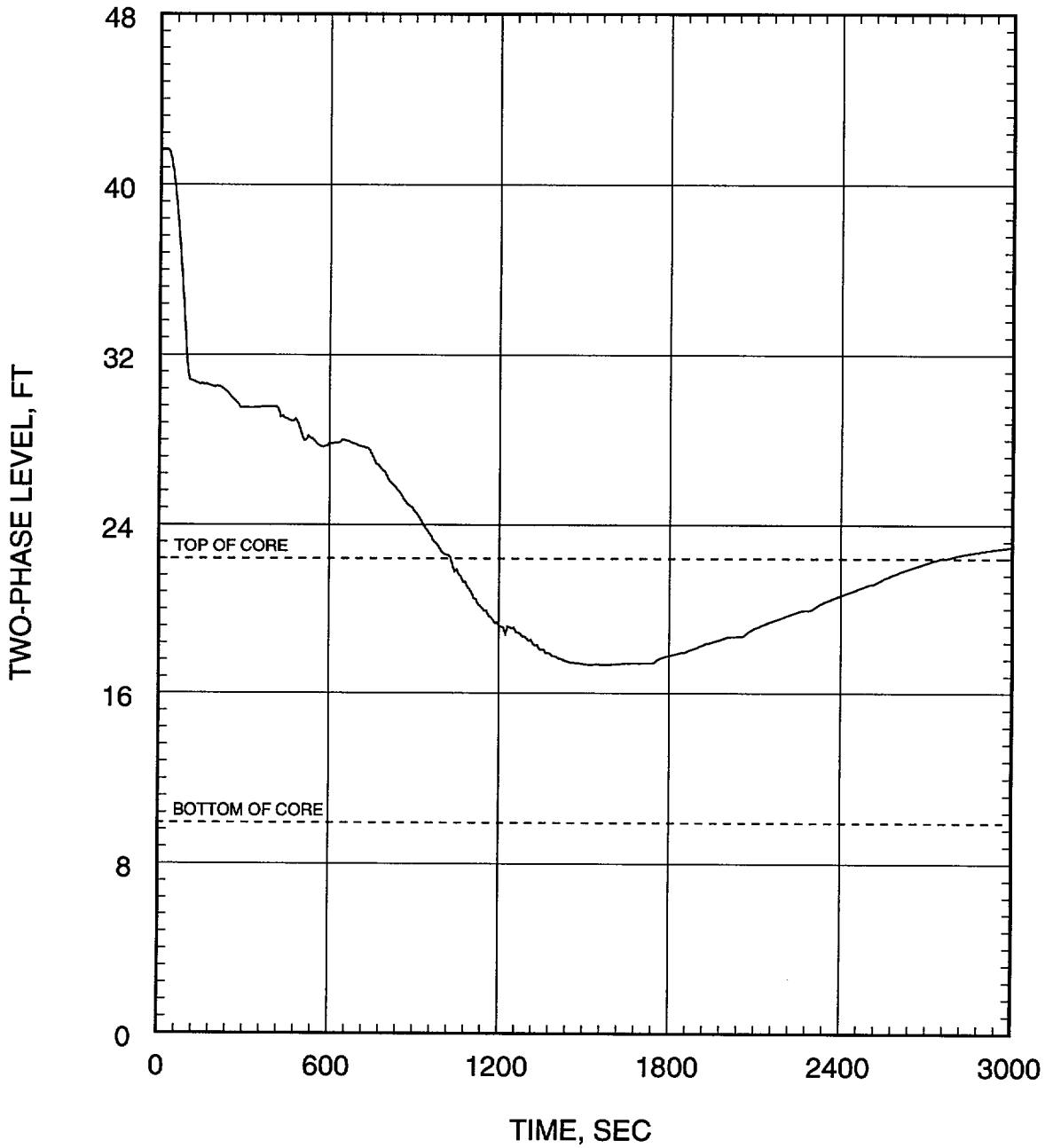


Figure 1.2-14

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

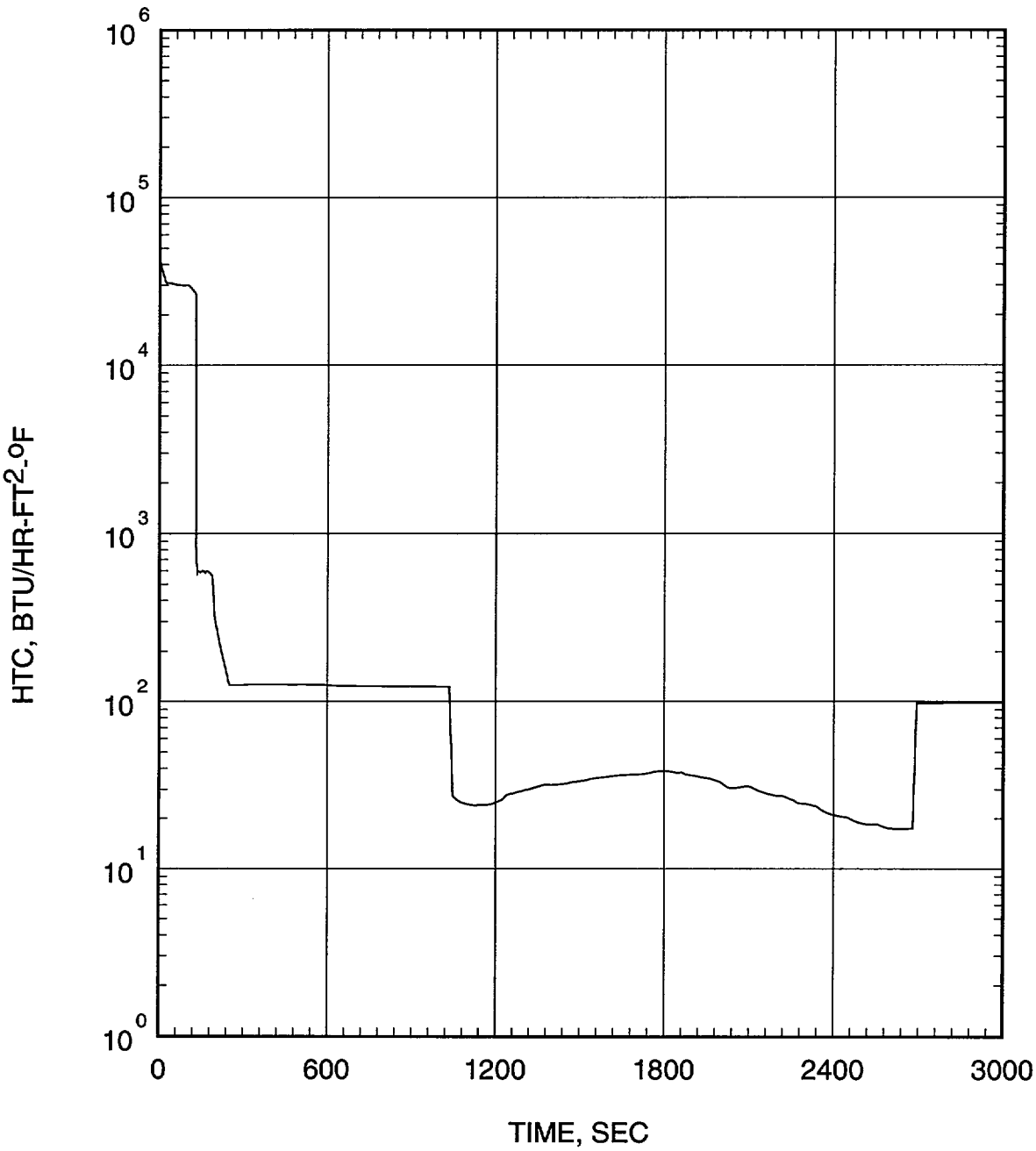


Figure 1.2-15

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Coolant Temperature at Hot Spot

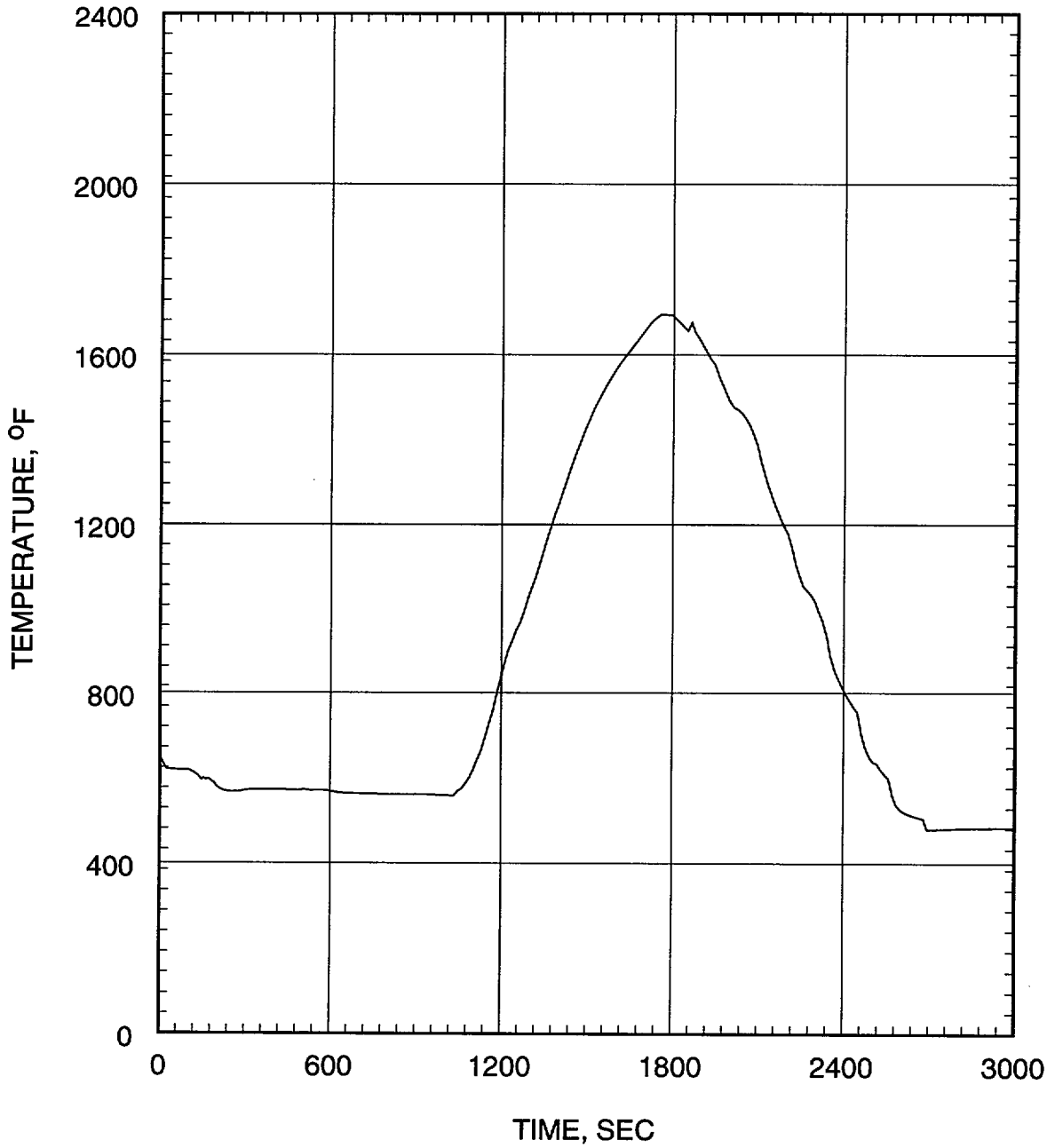


Figure 1.2-16

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Cladding Temperature at Hot Spot

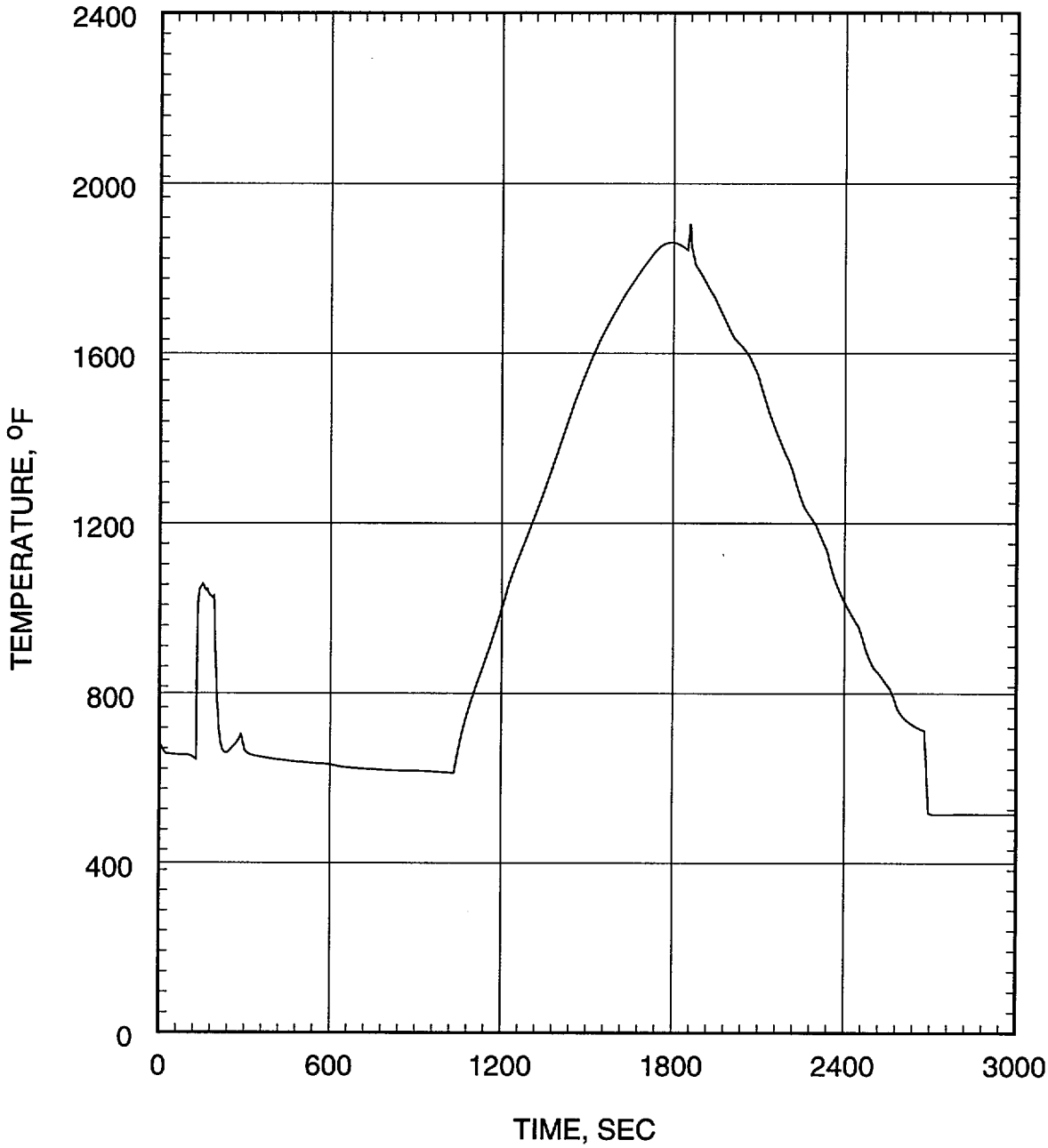


Figure 1.2-17

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Core Power

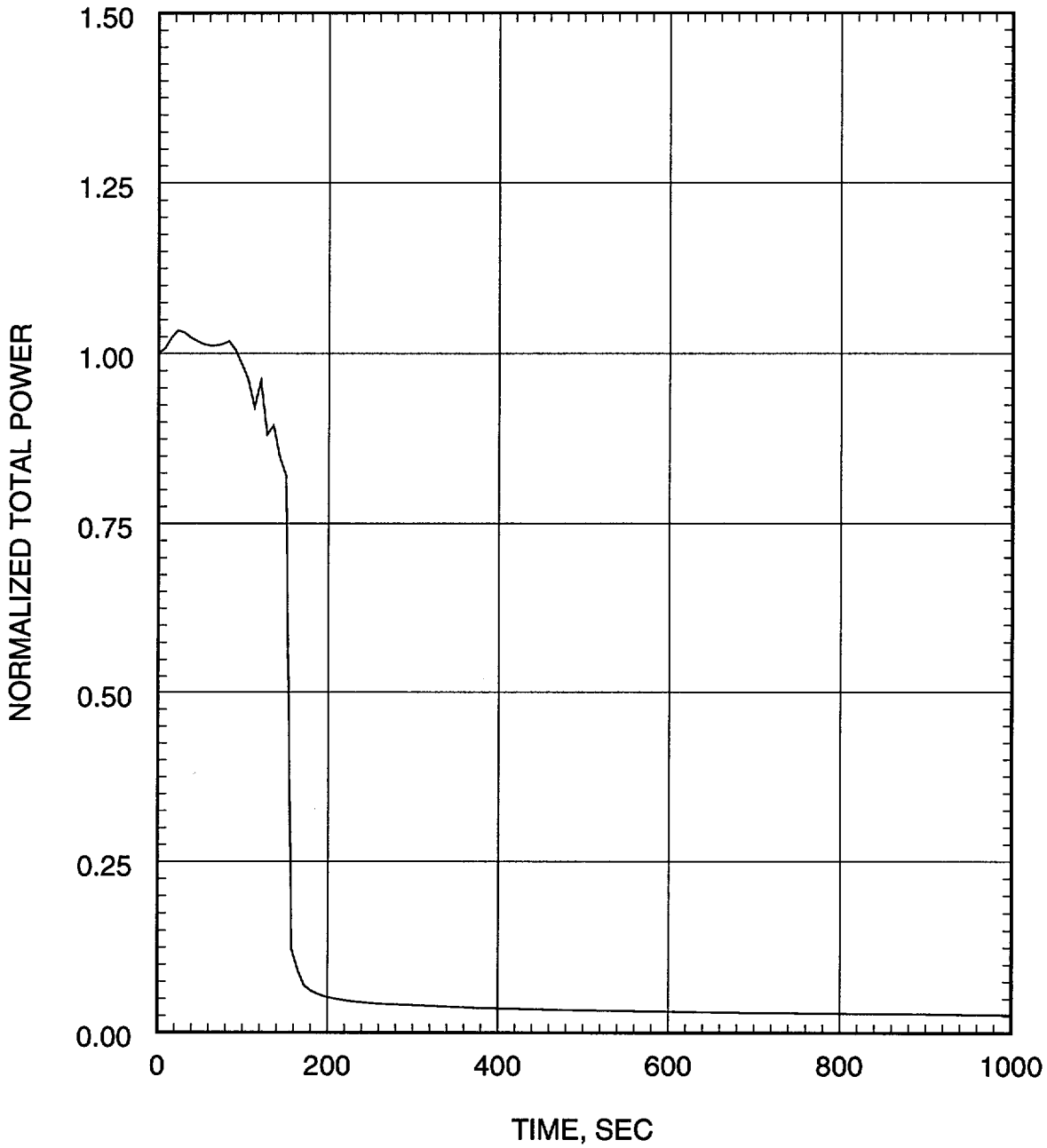


Figure 1.2-18

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Inner Vessel Pressure

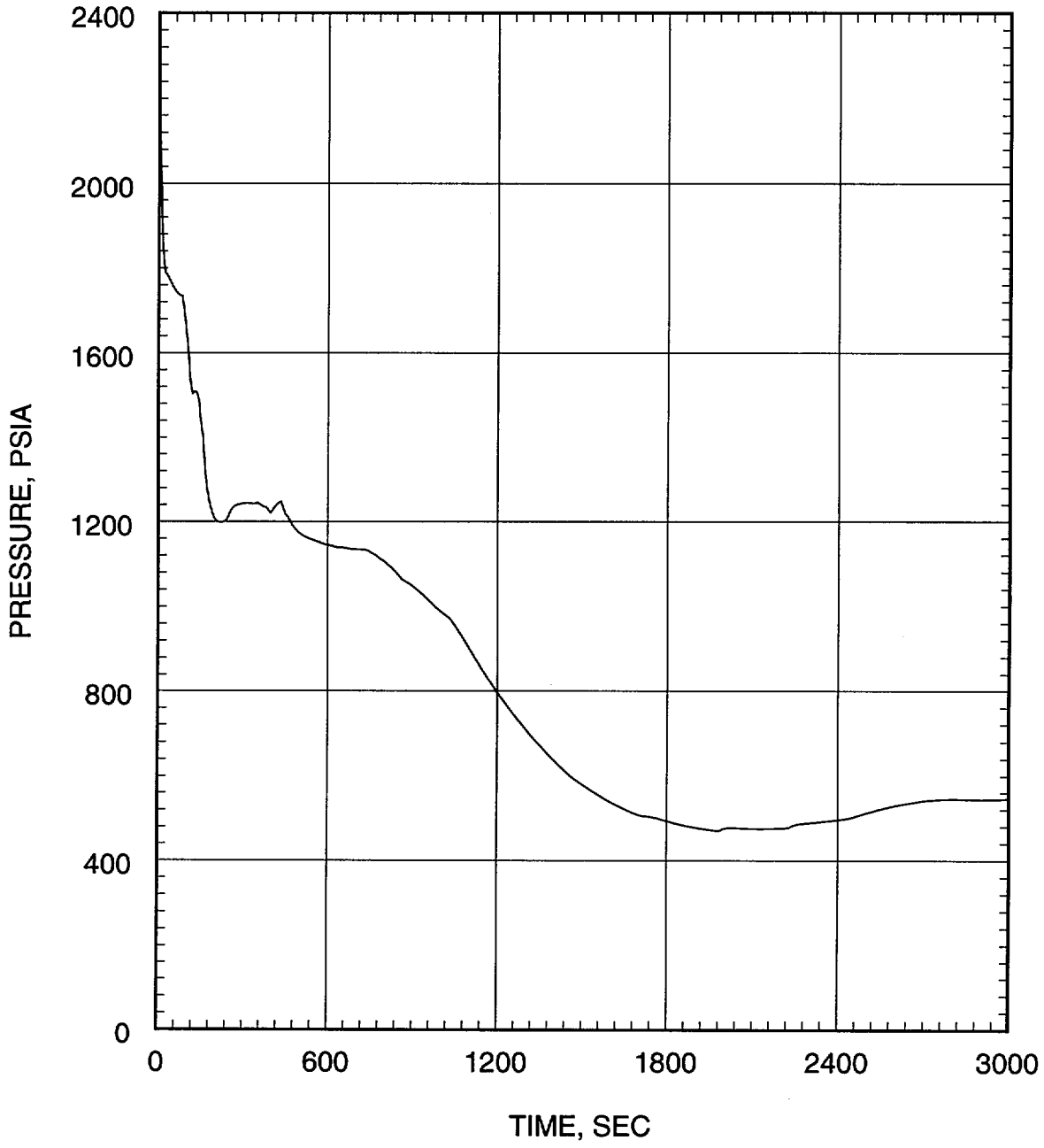


Figure 1.2-19

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Break Flow Rate

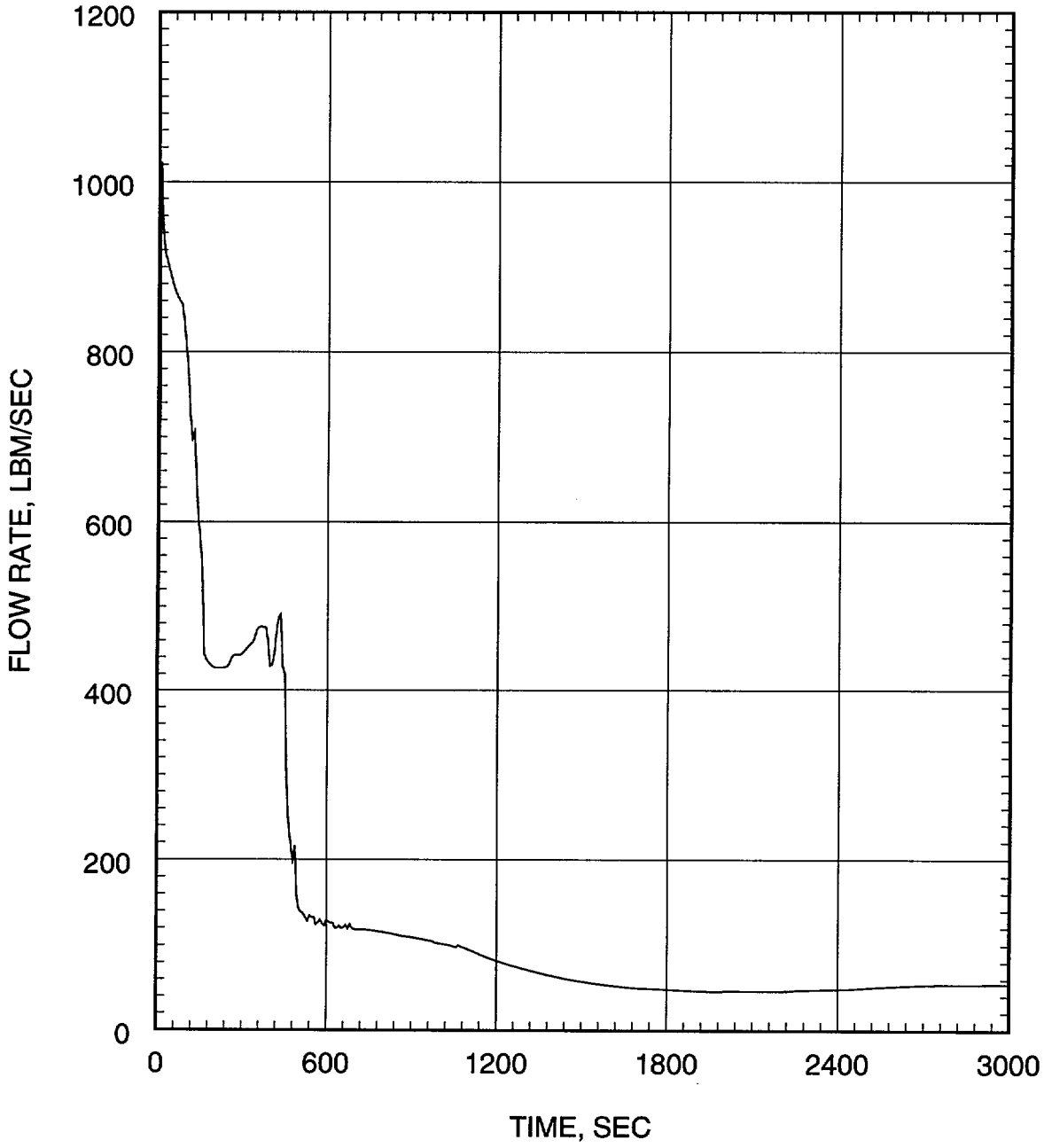


Figure 1.2-20

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Inner Vessel Inlet Flow Rate

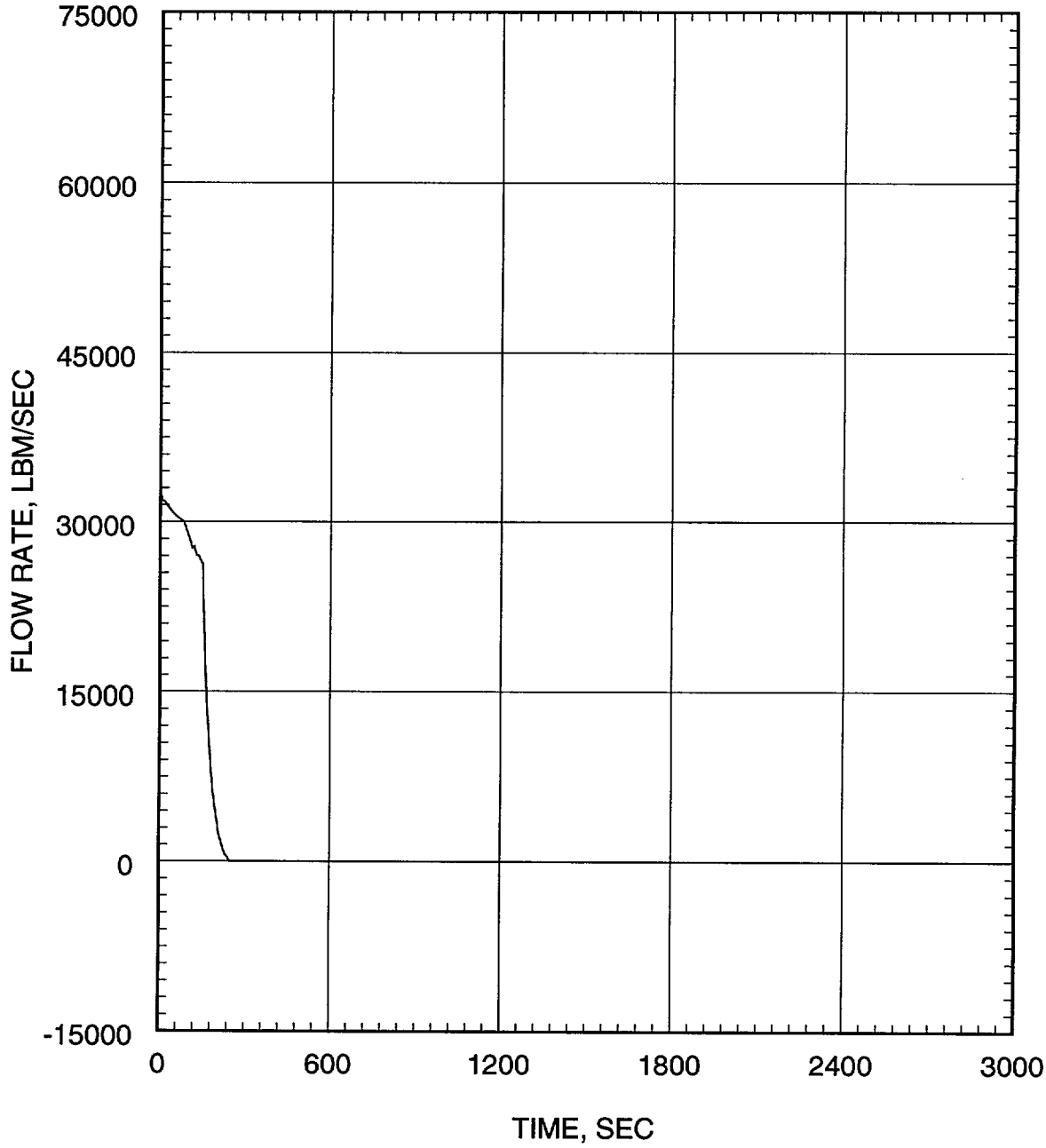


Figure 1.2-21

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Inner Vessel Two-Phase Mixture Level

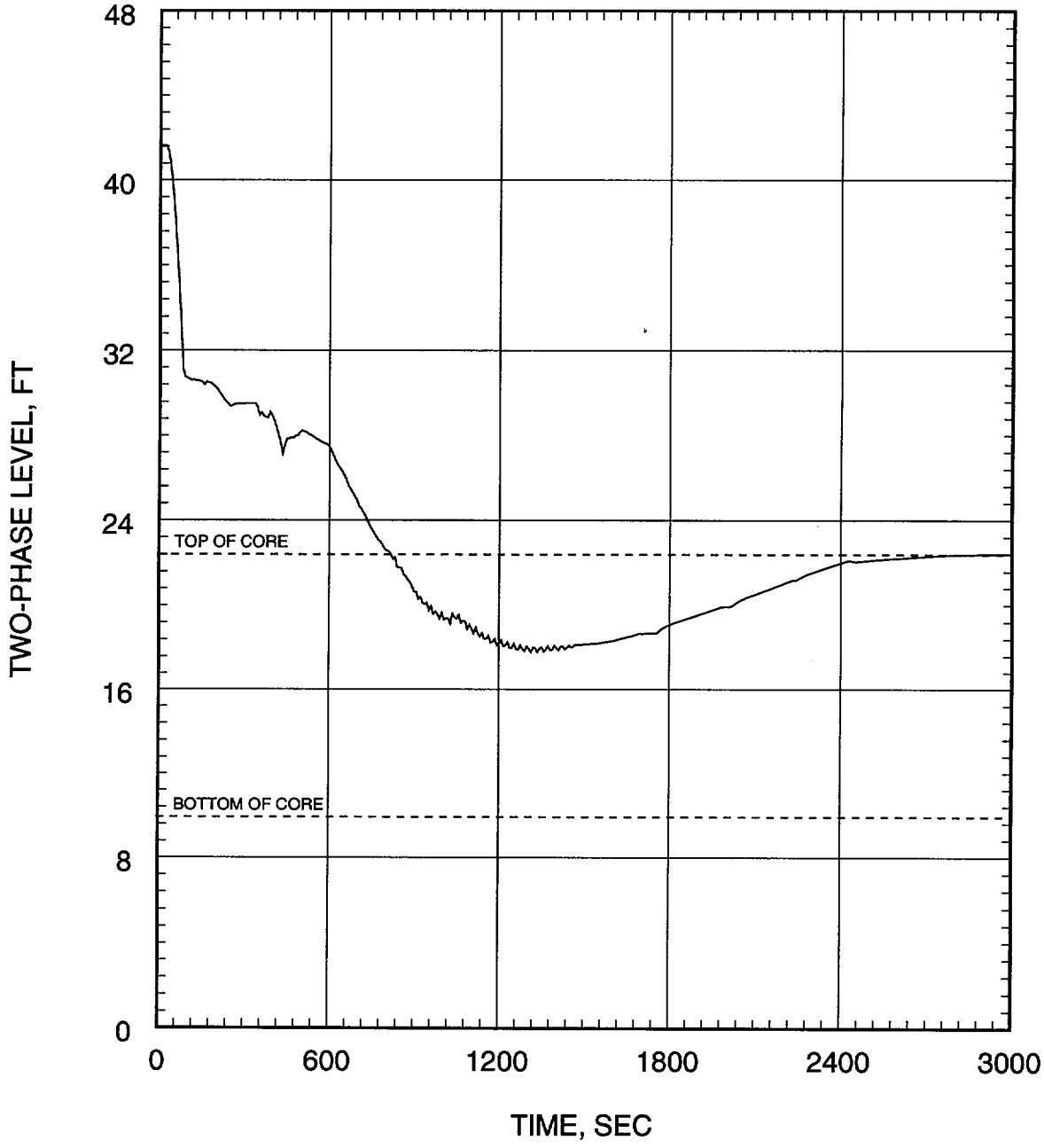


Figure 1.2-22

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

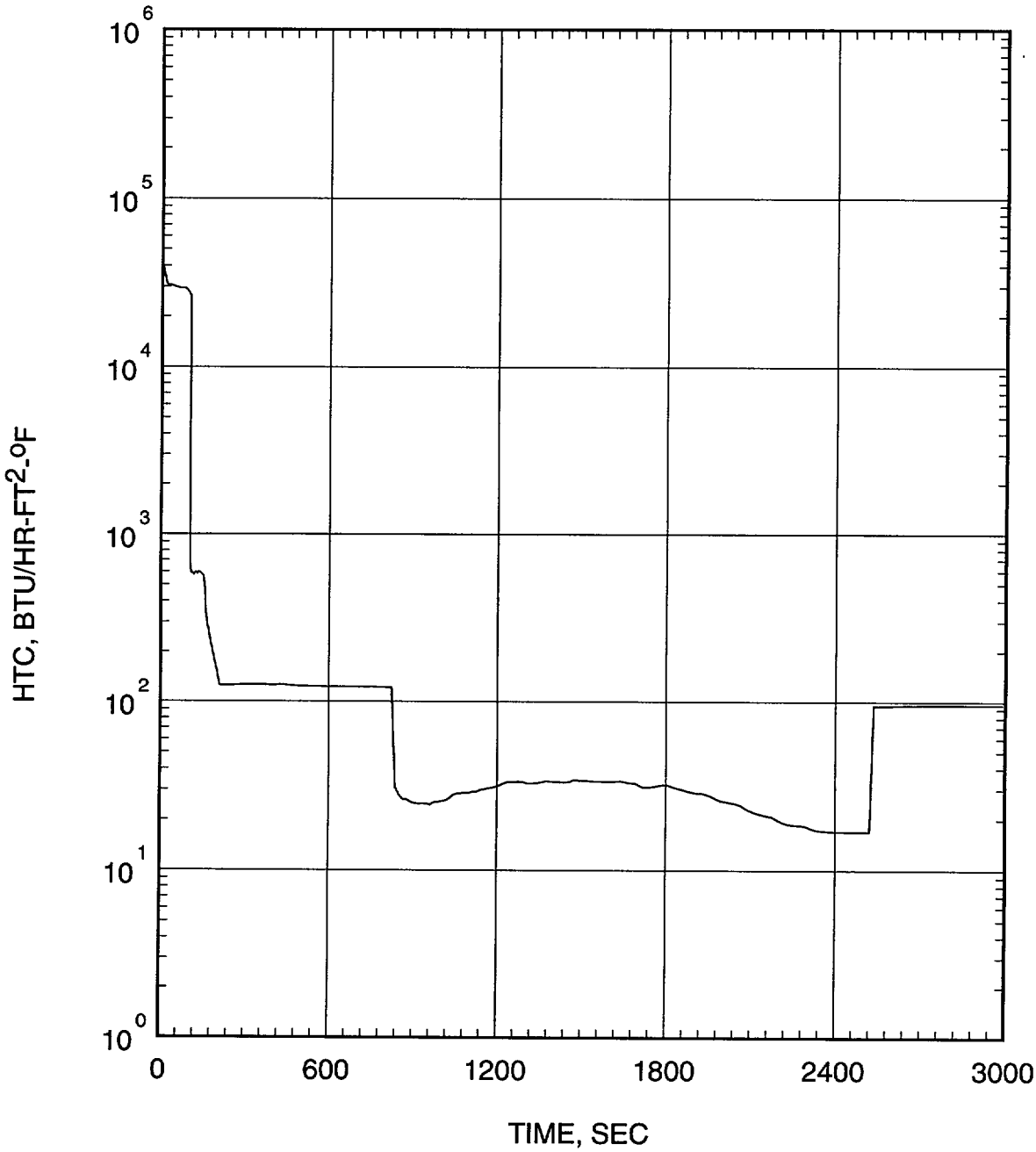


Figure 1.2-23

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Coolant Temperature at Hot Spot

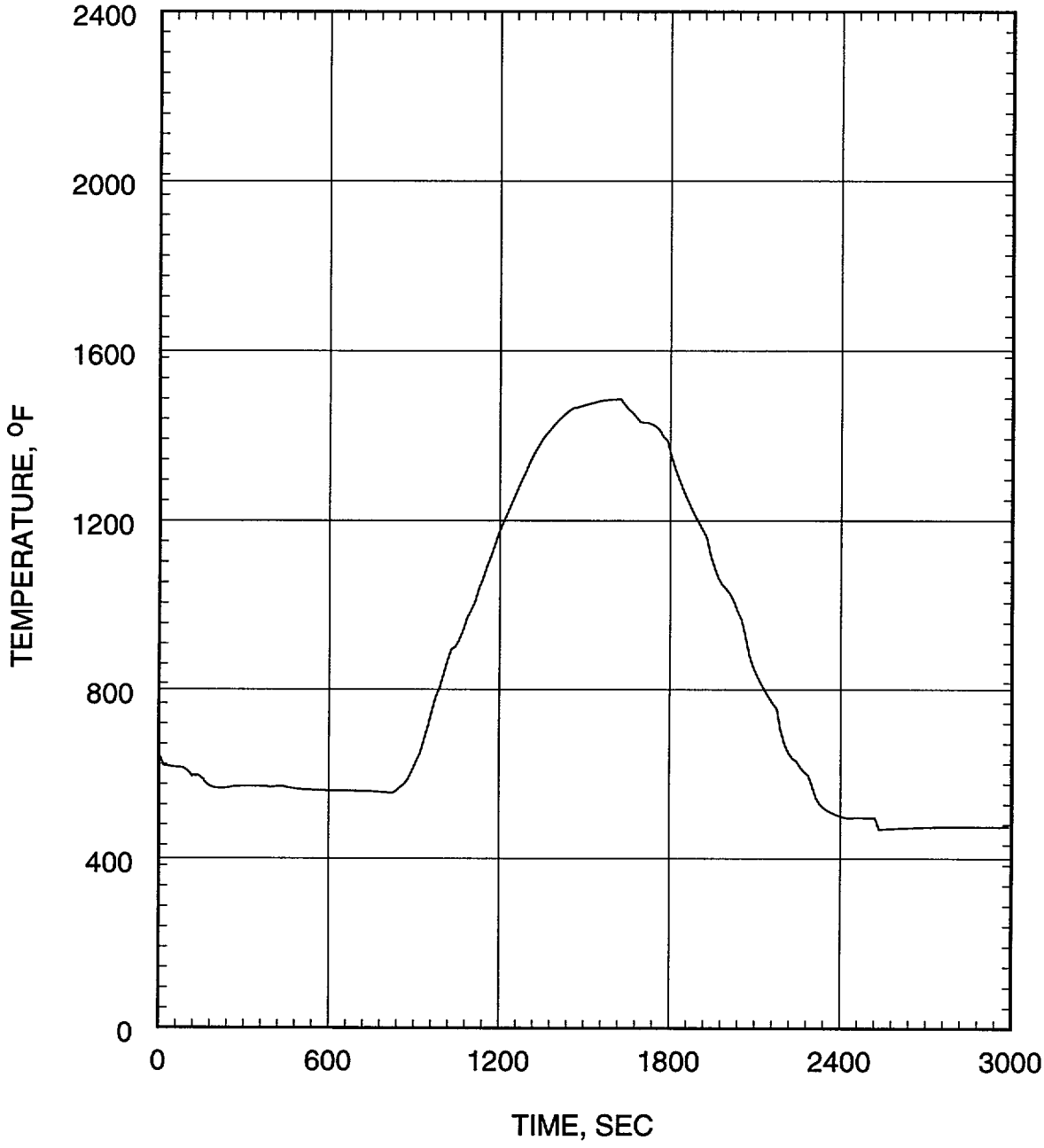
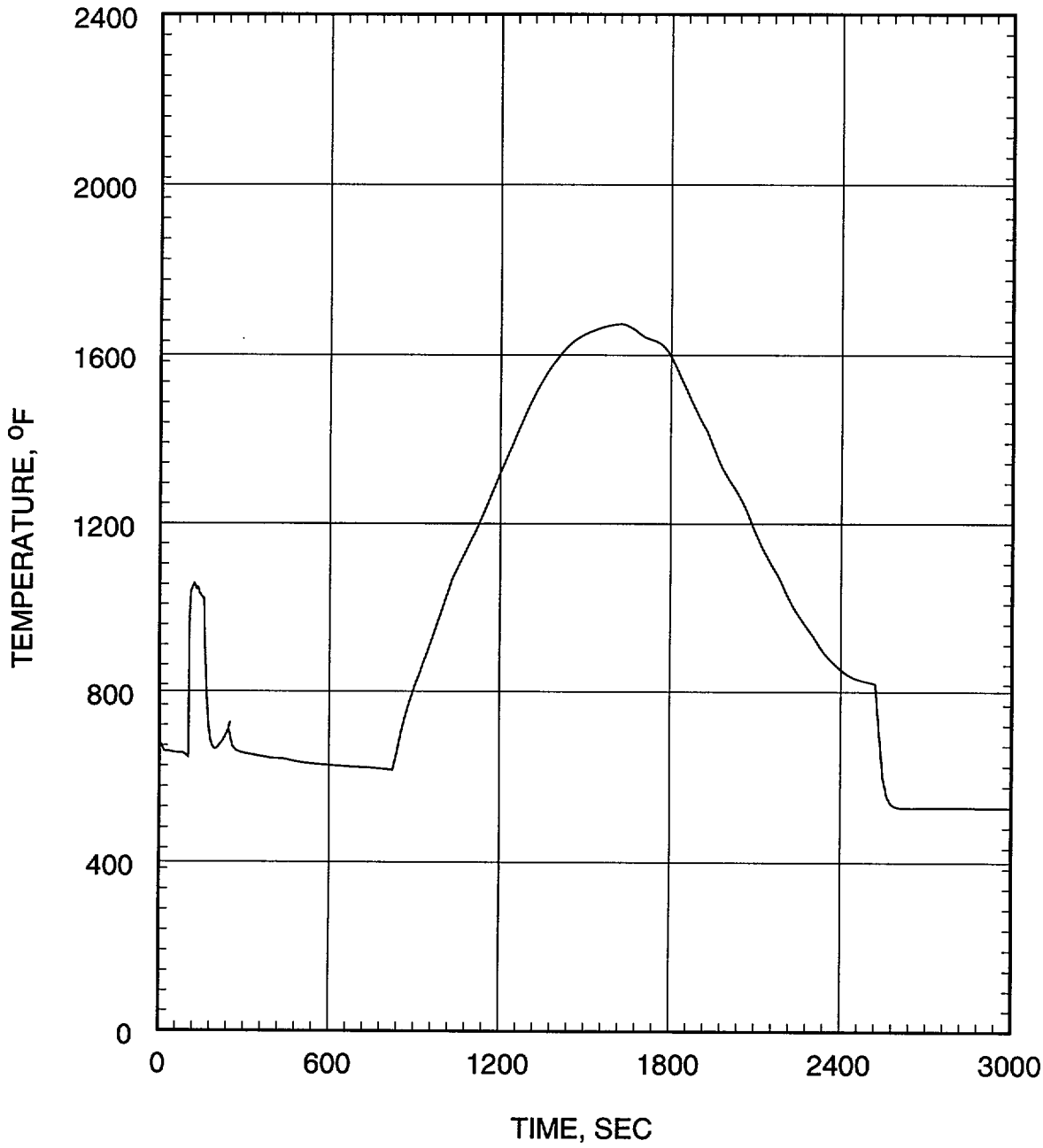


Figure 1.2-24

ANO-2 RSG Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Cladding Temperature at Hot Spot



ENCLOSURE 4

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NON-LOCA TRANSIENT ANALYSIS

1 Non-LOCA Transients

1.0 Introduction

Table 1.0-1 is a listing of the events presented in Chapter 15 of the ANO-2 Safety Analysis Report (SAR). In the right hand column of the table, a note has been placed delineating the level of effort in addressing the effect of these Technical Specification (TS) change requests associated with the installation of the Replacement Steam Generators (RSGs) on each non-LOCA Design Basis Event (DBE). Notes in the right hand column indicate: Evaluated, Reanalyzed, Not Reanalyzed, and Not Applicable. An event that is impacted by these requested TS changes, but that may be addressed qualitatively, is indicated as Evaluated. Qualitative arguments and some simple quantitative efforts address these events. Events in which the effects of the requested TS changes necessitated a new analysis have been indicated as Reanalyzed. In some cases, a complete reanalysis was performed, not necessarily due to the TS changes, but due to a combination of the TS changes and RSG changes. Not Reanalyzed has been used to denote events which are not impacted by the TS changes. Events identified as not applicable in the ANO-2 SAR are denoted as Not Applicable.

A summary of the analysis or evaluation, as appropriate, performed for each event affected by these proposed Technical Specification changes is provided in the following sections. Plugging of up to 10% of the steam generator tubes has been assumed as appropriate in the analyses described below.

The installation of the RSGs results in the following changes that need to be accommodated.

1. The RSGs are larger than the original steam generators (OSGs). This results in a larger secondary side mass.
2. The larger RSGs also contain more U-tubes than the OSGs, which increased the reactor coolant system (RCS) or primary side volume (and mass).
3. The larger RSGs have increased RCS flow (from the current degraded OSG condition) and the primary-to-secondary heat transfer area.
4. Larger heat transfer areas resulted in higher operating steam generator pressures.
5. The RSGs include an internal steam flow-limiting nozzle, which reduces the effective area of the steamline to less than two square feet.
6. Level tap locations in the RSGs differ from those of the OSGs, resulting in different levels and masses at which the Low Steam Generator Level Trip and Emergency Feedwater Actuation System (EFAS) setpoints occur.

In addition to RSG changes, other plant parameter changes have been incorporated. To obtain acceptable results, the following changes in the Reactor Protection System (RPS) and Engineered Safety Feature Actuation System (ESFAS) parameters were assumed.

1. The High Linear Power Trip setpoint was lowered for conditions when 2 or more Main Steam Safety Valves (MSSV) are inoperable on a single steam line in Modes 1, 2, and 3.

2. A moderator temperature coefficient (MTC) versus Rated Thermal Power plot has been developed to establish the appropriate High Linear Power Trip setpoint for conditions when an individual MSSV or when one MSSV per SG are inoperable in Modes 1, 2, and 3. Additionally, an MTC versus effective full power days (EFPD) correlation will be developed for Arkansas Nuclear One – Unit 2 (ANO-2) Operating Cycles 15 and 16.
3. The analytical High Pressurizer Pressure Trip setpoint and response times have been reduced.
4. The Low Steam Generator Level Trip and EFAS setpoints have been changed.
5. The Low Steam Generator Pressure trip and Main Steam Isolation Signal (MSIS) setpoints have been increased.
6. The Safety Injection Actuation Signal (SIAS) setpoint and analytical High Pressure Safety Injection (HPSI) response time have changed.
7. The analytical MSIS response times for the Main Steam Isolation Valves (MSIV) and Main Feedwater Isolation Valves (MFIV) have been increased.
8. The analytical response time of the High Containment Pressure Trip has been reduced.

Other major changes that impact the safety analyses are:

1. A larger excess steam flow capacity for the main turbine.
2. The minimum and maximum analytical RCS flow range has increased.

To accommodate the RSGs, and in specific cases the power uprate, the following analytical method changes have been applied:

1. Credit for the High Containment Pressure Trip during a Main Steam Line Break (MSLB) inside containment is assumed.
2. Credit for the Safety Injection Tanks (SIT) during a MSLB is assumed.
3. The method of calculating the time-of-trip for the Feedwater Line Break (FWLB) analysis has been changed.
4. The Napier correction factor was used to correct the Pressurizer Safety Valve (PSV) flow.
5. The uncertainties for the analytical RPS and ESFAS setpoints were based on three different conditions:
   a. normal – a high energy pipe break does not exist,
   b. abnormal – containment conditions during a high energy pipe break result in a High Containment Pressure Trip.
   c. harsh – containment conditions during a high energy pipe break reach containment design limits.
6. A different radiological dose methodology has been utilized.

The RSGs will restore operating steam generator pressure to values above ANO-2 Cycle 1 values. This increase in operating pressure has allowed for the restoration of the Low Steam Generator Pressure Trip setpoint to a higher value. This setpoint is credited for the FWLB Accident, the Excess Heat Removal due to Main Steam System Malfunction event, and the Major Secondary System Pipe Break Accident analyses which follow.

A new Low Steam Generator Level Trip setpoint has been used in the following analyses. The lower setpoint is being proposed due to a combination of the larger steam generator and the change in level tap locations. With the current steam generators, most uncomplicated reactor trips from higher power levels result in emergency feedwater (EFW) actuation. A combination of the RSG design features and this new lower level setpoint should allow avoidance of unneeded EFW actuation, yet ensure EFW actuation occurs when it is needed. The Low Steam Generator Level Trip setpoint is credited in the Loss of Normal Feedwater Flow, Feedwater Line Break Accident, and Loss of External Load and/or Turbine Trip analysis (MSSV out of service cases). The results of these analyses with the new low level setpoint follow, demonstrating acceptable results.

The RSGs are expected to restore RCS flow back to values that existed prior to extensive tube plugging of the OSGs. This increase in flow will allow for the RCS minimum flow TS limit to be restored to the original value of 120.4 x 10^6 lbm/hr. The original design flow was based on a volumetric flow rate of 322,000 gpm, which was converted to a mass flow rate at nominal operating conditions (approximately 553° F). In all of the following analyses that were reanalyzed, a minimum RCS flow of less than 120.4 x 10^6 lbm/hr has been applied. Many of the analyses use 98% of 322,000 gpm (315,560 gpm) or 98% of 120.4 x 10^6 lbm/hr (118 x 10^6 lbm/hr).

The RSGs will result in a slightly larger primary system volume. This increase in volume will result in a slightly greater level shrink following a plant trip and also result in slightly lower RCS pressures. The lower RCS pressures will more closely approach the current Low Pressurizer Pressure Trip and SIAS setpoint. To aid in avoiding undesired SIAS actuation following an uncomplicated reactor trip, a lower Low Pressurizer Pressure Trip setpoint is being proposed. This new setpoint is based on the limiting analysis, including instrument uncertainty. The Loss of Coolant Accident (LOCA) analysis discussed in Enclosure 3 and all of the following analyses use an analytical assumption of 1400 psia (Major Secondary System Pipe Break Accident and Excess Heat Removal due to Main Steam System Valve Malfunction) except the Steam Generator Tube Rupture (SGTR) event which assumes 1600 psia. The proposed TS value is conservatively based on the SGTR analysis assumption of 1600 psia, including the impacts of instrument uncertainty.

The MSSV out-of-service High Linear Power Trip setpoint analysis based on an assumed Loss of Condenser Vacuum (LOCV) event is affected because of the larger primary to secondary heat transfer area of the RSGs, the new Low Steam Generator Level Trip setpoint, and consideration of power uprate. As a result of these various changes, new High Linear Power Trip setpoints have been determined. To aid in offsetting the above changes, a new analysis approach was used that is based on one individual MSSV and/or one MSSV on each steam header being out-of-service. The two new cases additionally credit the time-in-core-life MTC to aid in allowing increased High Linear Power Trip setpoints when MSSVs are inoperable.

A new method of offsite release analysis has been implemented in this effort to assess the impacts of the larger RSG primary and secondary inventories. The new method is inconsistent with those currently presented in the SAR; however, it is more conservative than those presented in the SAR, and is essentially consistent with the approach used in the original Safety Evaluation Report (SER) and that used in ANO-2 TS Amendment 189 (March 12, 1998).

1.0.1 Input Parameters and Analysis Assumptions

Table 1.0.1-1 presents the key parameters assumed in the transient analyses. Specific initial conditions for each event are tabulated in that event's section. Events were evaluated to determine the effects from the requested TS changes, the RSGs, and relevant bounding parameters. For those events in which a detailed analysis was performed (see Table 1.0-1), the initial core power was assumed to be a rated core power of 3026 MWt, except for the Feedwater Line Break (FWLB) analysis. The current power rating of 2815 MWt was assumed for the FWLB analysis. Some input parameters included RPS response time changes, more negative moderator temperature coefficients, and higher RCS flow ranges.

One of the changes in analysis input was the implementation of the Napier correction associated with PSV flow. Per later versions of the ASME code (approved by NRC via 10CFR50.55a), for pressures greater than 1500 psig and up to 3200 psig, the PSV flow could be increased. For ANO-2, the Napier correction factor was determined to be 1.08. This increased flow rate is consistent with the ASME code allowable, which remains less than 90% of capacity.

Table 1.0.1-2 presents the RPS and ESFAS instrumentation trip setpoints and delay times.

The following is a summary of the changes in RPS and ESFAS setpoints. One major change in the RPS and ESFAS setpoints is in the application of uncertainties to the analytical setpoints. Previously, there were typically only two uncertainties: normal environment and harsh environment. Normal environment assumed no high-energy pipe break existed in containment. Harsh environment assumed the worst containment conditions expected during the high-energy pipe break. For the purposes of the new analyses, the harsh environment has been subdivided into two categories: harsh and abnormal.

The new uncertainty category is referred to as abnormal. The uncertainty for this category is based on the environmental conditions at which a High Containment Pressure Trip or High Containment Pressure SIAS setpoint is reached. The basis is that the trip or actuation function credited during high-energy pipe breaks need only include uncertainty equivalent to the condition at which the containment high pressure trip or actuation would occur. Any additional uncertainty on the credited trip or actuation function is not required since high containment pressure would have generated a reactor trip and SIAS. This approach has already been used in the current Low Pressurizer Pressure Trip and SIAS setpoint.

It should be noted that ANO uncertainty/setpoint calculations also use the term "abnormal" to describe worst case "normal" operating conditions. However, regardless of terminology used, the appropriate uncertainty for the conditions assumed to exist at the time of trip or actuation has been applied.

The High Pressurizer Pressure Trip analytical value was decreased from 2422 psia to 2415 psia for harsh environment, and to 2392 psia for normal environment. The analytical response time for the High Pressurizer Pressure Trip has decreased from 0.9 seconds to 0.65 seconds. The more rapid response time remains greater than the actual response time. The lower analytical setpoints including consideration of instrument uncertainties support the current TS setpoint of 2362 psia.

The Low Steam Generator Level Trip and EFAS analytical values have changed from 5% of the narrow range indication to:

> 9% of narrow range for normal environment (both EFAS and the Low Steam Generator Level Trip),
>
> 6% of narrow range for abnormal environment (Low Steam Generator Level Trip only), and
>
> 0% of narrow range for harsh environment (EFAS only).

The use of these analysis values and a break down of the instrument uncertainties has allowed the Low Steam Generator Level Trip and EFAS setpoints to be reduced from 23% to 22.2%. In the past, only harsh environment uncertainties were considered and the results added to the 5% analysis value. The more detailed method used in this analysis has allowed for a reduction in the Low Steam Generator Level Trip and EFAS setpoints. A lower setpoint, in combination with the increased secondary mass of the RSGs, should help avoid EFW actuation during uncomplicated reactor trips.

The analytical response time for the Low Steam Generator Level Trip has increased from 0.9 seconds to 1.3 seconds for conservatism purposes. The analytical response time for the Containment Pressure – High Trip has been re-evaluated and some excess conservatism removed; the analytical response time has decreased from 1.59 seconds to 1.2 seconds, but still exceeds the actual response time.

The Low Steam Generator Pressure Trip and MSIS analytical values have increased from 620 psia to 693 psia normal environment and 658 psia for harsh environment. The analytical setpoints of 693 psia and 658 psia, in combination with the appropriate instrument uncertainties, support the proposed TS value of 751 psia. For conservatism purposes, the analytical response time for the Low Steam Generator Pressure Trip has increased from 0.9 seconds to 1.3 seconds and the analytical response time for the MSIS has increased from 0.9 seconds to 1.4 seconds. In addition more conservative, longer analytical closing values were assumed for the Main Steam Isolation Valves (MSIVs), Main Feedwater Isolation Valves (FWIVs), and the back-up FWIVs. The assumed MSIV closing time increased from 3.9 seconds to 4.9 seconds which includes the MSIS response time. The assumed FWIV closing time has increased from 36.4 seconds (loss of AC power) and 21.4 seconds (AC power available) to 41.4 seconds and 26.4 seconds respectively. The assumed backup FWIV closing time has increased from 31.8 seconds (loss of AC power) and 16.8 seconds (AC power available) to 34.9 seconds and 19.9 seconds respectively.

For the events that are reanalyzed in support of this report, the Low Pressurizer Pressure Trip and SIAS analytical values assume an RCS pressure of 1400 psia. The SGTR event was not reanalyzed and remains based on an analytical value of 1600 psia. The analytical values of 1400 psia and 1600 psia in combination with the appropriate instrument uncertainties support the proposed TS Low Pressurizer Pressure Trip and SIAS setpoint of 1675 psia. For conservatism purposes, the Low Pressurizer Pressure Trip analytical response time was assumed to increase from 0.9 seconds to 1.2 seconds and the SIAS analytical response time for the HPSI pumps, including diesel generator startup time, was increased from 30 seconds to 40 seconds.

1.0.2 Bounding Physics Data

Many of the analyses presented below were performed using bounding core physics data. MTC, fuel temperature coefficient (FTC or Doppler), delayed neutron fractions, effective neutron lifetime, and control element assembly (CEA) reactivity ($\Delta\rho$) insertion curves are core physics parameters that are typically considered on a cycle specific basis and are inputs to many of the analyses discussed below. A bounding set of physics data will be presented first, allowing the respective analyses to refer to this data as it is applied. Detailed core physics data that affects a particular analysis will be discussed for that analysis.

A MTC within the ranges defined in Figure 1.0.2-1 was assumed in the following analyses.

Figure 1.0.2-2 represents the bounding FTC reactivity curves, including uncertainties, for the Beginning of Cycle (BOC) and the End of Cycle (EOC). The curves have been used as specified in the specific analysis.

The CEA reactivity insertion curve assumed for the following analyses is presented in Figure 1.0.2-3. The scram curve is based on an Axial Shape Index (ASI) of + 0.3. A CEA insertion curve consistent with Figure 1.0.2-4 utilizing a 0.6 second holding coil delay time and a 3.2 second arithmetic average drop time to 90% inserted was assumed. An assumed shutdown worth of 5% $\Delta\rho$ is incorporated into Figure 1.0.2-3.

The following effective neutron lifetime and delayed neutron fraction were established for the following analyses. These parameters were used as indicated in the respective analyses.

	Neutron Lifetime, 10^{-6} seconds	Delayed Neutron Fraction
Beginning of Cycle	13	0.007252
End of Cycle	36	0.004341

1.0.3 Computer Codes

The transient analysis methodology used for the RSG analysis is similar to the methodologies documented in the current SAR, except when noted. For explicit transient analyses, the CENTS code from Reference 1-2 was employed.

The minimum departure from nucleate boiling ratio (DNBR) and the departure from nucleate boiling (DNB) thermal margin analyses were determined using the CETOP code described in Reference 1-3. This method was approved as documented in Reference 1-10.

Although the Loss of Flow in Section 1.3.1 was not reanalyzed, the evaluation was based on parametric studies performed with the HERMITE code described in Reference 1-4.

1.0.4 Radiological Dose Input Parameters

A radiological analysis was performed to support the RSGs and power uprate. The following inputs and assumptions used in this analysis differ from those listed in the SAR Sections 15.1.0.5.1 through 15.1.0.5.4 (Reference 1-1). The differences are more conservative analysis assumptions than those identified as the original analysis requirements.

A. A constant secondary side activity equal to 0.1 μCi/g DEQ (dose equivalent) I-131;

B. A constant primary side activity equal to 1.0 μCi/g DEQ I-131;

C. A constant primary side noble gas activity of $100/E_{bar}$ μCi/g for non-fuel failure analyses, where E_{bar} is defined as the average of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes other than iodines;

D. RCS activity for fuel failure analyses is based on the pin activities in Table 1.0.4-1;

E. A continuous primary to secondary leak rate of 150 gallons per day per steam generator, except for events which result in a significant primary to secondary pressure differential (main steam line breaks and main feedwater line breaks) which use 0.5 gallon per minute;

F. An activity discharged through steaming determined by a time dependent mathematical model;

G. Isotopic data given by Tables 1.0.4-2A and B;

H. Whole Body dose consequences defined by:

$$D_{WB} = (\chi/Q) \times \sum_j A_j \times DCF_j$$

where:

D_{WB}	=	Whole body dose (rem)
A_j	=	Activity release of isotope *j* (Ci), for all isotopes
DCF_j	=	Whole Body Dose Conversion Factor isotope *j* (rem-m^3/s-Ci)
(χ/Q)	=	Atmospheric dilution (s/m^3) from Table 1.0.4-3

ICRP-2 values for the DCF were used for events without fuel failure. These values are given in Table 1.0.4-2B. For these events, the DCF_j were calculated by:

$$DCF_j = DCF_{\gamma j} + DCF_{\beta j}$$

ICRP-30 values for the DCF_j were used for events with fuel failure. These values are given in Table 1.0.4-2A.

I. Thyroid dose consequences defined by:

$$D_{Thyroid} = (\chi/Q) \times B \times \sum_i A_{I,i} \times DCF_{I,i}$$

where:

$D_{Thyroid}$	=	Thyroid dose (rem)
$A_{I,i}$	=	Activity release of Iodine isotope *i* (Ci)
$DCF_{I,i}$	=	Thyroid Dose Conversion Factor for Iodine Isotope *i* (rem-m^3/s-Ci)
B	=	Breathing Rate (m^3/s) from Table 1.0.4-4
(χ/Q)	=	Atmospheric dilution (s/m^3) from Table 1.0.4-3

ICRP-2 values for the $DCF_{I,i}$ were used for events without fuel failure. These values are given in Table 1.04-2B.

ICRP-30 values for the $DCF_{I,i}$ were used for events with fuel failure. These values are given in Table 1.0.4-2A.

J. Iodine Release from the Steam Generators was determined by:

For events, which result in steam generator dryout, all of the iodine activity of the dry steam generator is released.

For all other events, an iodine partition factor of 100 is assumed.

K. For iodine spiking considerations in non-fuel failure postulated accident events, a pre-existing spike of 60 times the normal and an event generated spike with a spiking factor of 500 assuming normal operation with one charging pump running is assumed;

L. A core power of 3087 MWt;

M. The Exclusionary Area Boundary (EAB) doses are based on a 2-hour release duration (approximately 670,000 lbm). The Low Population Zone (LPZ) doses are based on an 8-hour cooldown to shutdown cooling entry conditions (approximately 1,770,000 lbm). Offsite releases are assumed to cease upon initiation of shutdown cooling.

In addition to the inputs assumed above, the following assumptions are made:

1. No credit for operator action is assumed to occur until plant stabilization, 30 minutes after the transient. Hence, no credit for plant cooldown toward shutdown cooling conditions is assumed until 30 minutes into the transients.

2. It is assumed that the operators maintain the plant 20° F subcooled during cooldown.

3. In order to maximize the amount of activity available in the core, all pins in the core were assumed to be fuel pins (no poison pins or shims).

No radiological doses were explicitly calculated for Anticipated Operational Occurrences (AOO) since the results of these events should be acceptable based on bounding doses resulting from either the FWLB event discussed in Section 1.4.4 of this enclosure or the MSLB event discussed in Section 1.5.3 of this enclosure.

The MSLB and FWLB whole body doses are less than 0.1 rem for all cases. Additionally, the thyroid doses are less than 10 rem for all cases. For the MSLB and FWLB events, the radiological releases are overly conservative for AOOs since the MSLB and FWLB events have assumed that at least one steam generator goes dry. This results in a steam generator iodine decontamination factor (DF) of 1, versus a DF of 100 for a generator that maintains its inventory. For most AOOs, the steam generators never go dry, hence a DF of at least 100 (400 based on original SAR analyses) will substantially reduce the presented thyroid doses. Additionally, offsite power availability in most AOOs allows for additional scrubbing of releases due to the availability of the condenser.

1.1 CEA Events

1.1.1 Uncontrolled CEA Withdrawal from Subcritical Conditions

Summary

The objective of the Subcritical CEA Bank Withdrawal event evaluation is to determine the impact of the RSGs and the increase in RCS minimum flow for Cycle 15.

There are no significant impacts due to the RSGs. The increase in RCS flow will have a small beneficial impact on the analysis results.

General Description of the Event

The withdrawal of CEAs from subcritical conditions (less than 10^{-4} percent power) inserts positive reactivity to the reactor core, causing both the core power level and the core heat flux to increase. Since the transient is initiated at low power levels, the normal reactor feedback mechanisms (moderator feedback, and Doppler feedback) do not occur until power generation in the core is large enough to cause changes in the fuel and moderator temperatures. The RPS is designed to prevent such a transient from resulting in a minimum DNBR less than 1.25 by initiating a High Logarithmic Power Level reactor trip. The High Linear Power Level Trip and the Core Protection Calculators (CPC) Variable Overpower Trip (VOPT), High Local Power Density (LPD) trip and low DNBR trip provide backup protection while the High Pressurizer Pressure Trip provides protection for the reactor coolant pressure boundary.

A continuous withdrawal of CEAs could result from a malfunction in the Control Element Drive Mechanism Control System (CEDMCS) or by operator error.

Startup of the reactor involves a planned sequence of events during which certain CEA groups are withdrawn at a controlled rate and in a prescribed order, to increase the core reactivity gradually from subcritical to critical. To ensure that rapid shutdown by CEA insertion is always possible when the reactor is critical or near critical, TSs require that specified groups of CEAs be withdrawn before reaching criticality. These groups of assemblies combined with soluble boron concentration will have a total negative reactivity worth that is sufficient to provide at least the TS required shutdown margin (SDM) at the hot standby condition, with the most reactive CEA assumed to remain in the fully withdrawn position following a reactor trip.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the Specified Acceptable Fuel Design Limits (SAFDL) are not violated and the peak RCS pressure remains below the upset pressure criterion.

The criteria for the CEA Bank Withdrawal from Subcritical event are the following:

DNBR $\geq$ DNB SAFDL
Fuel Centerline Temperatures < Fuel Centerline Melt Limit
Peak RCS Pressure $\leq$2750 psia

The CEA Bank Withdrawal from Subcritical event is described in Chapter 15.1.1 of the SAR (Reference 1-1).

Impact of Changes

The RSGs do not result in any changes to key input data for the CEA Bank Withdrawal from Subcritical event. The core physics, reactivity insertion rate of the CEA bank withdrawals, 3-D power peaks, kinetics parameters, Doppler coefficient and MTC dominate this event. The increase in RCS flow has a small beneficial impact on the analysis results.

Analysis Overview

The method used in this evaluation was to perform a comparison of key plant and physics input parameters between those used in the analysis of record versus the new input data due to the RSGs and other plant changes.

Analysis Results

Since the proposed TS changes and the RSGs do not negatively impact the results, the results are bounded by the current analysis.

1.1.2 Uncontrolled CEA Withdrawal from Critical Conditions

Summary

The objective of the Uncontrolled CEA Bank Withdrawal from critical condition event evaluation is to determine the impact of the RSGs and the increase in RCS flow for Cycle 15.

There are no significant impacts due to the RSGs. The increase in RCS flow will have a small beneficial impact on the analysis results.

General Description of the Event

The withdrawal of CEAs from a critical condition (greater than 10^{-4} percent power) inserts positive reactivity in to the reactor core, causing the core power level to increase. A continuous withdrawal of CEAs could result from a malfunction in the CEDMCS or by operator error. No failure that can cause a CEA withdrawal can prevent the insertion of CEA banks upon receipt of any RPS trip signal.

Analyses have shown that the most adverse results for the CEA withdrawal events occur with the maximum reactivity addition rates. The analysis of the CEA withdrawal from critical conditions therefore utilizes the maximum reactivity addition rate with the CEA withdrawal speed of 30 in/minute.

The sequential CEA withdrawal events from critical conditions are considered from hot zero power (HZP) and hot full power (HFP) conditions.

The sequential CEA withdrawal event are terminated by a CPC Low DNBR trip, CPC High LPD trip, or a CPC VOPT. The CPC has dynamic compensation lead-lag filters that project increases in core heat flux and core power. These dynamic compensation filters in conjunction with power correction factors ensure that the CEA withdrawal transients are terminated prior to the SAFDLs being violated.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine that the SAFDLs are not violated, the peak RCS pressure remains less than 2750 psia, and that a secondary heat sink is maintained.

The criteria for the CEA Bank Withdrawal from critical event is the following:

DNBR ≥ DNB SAFDL
Peak Linear Heat Rate (LHR) ≤21 KW/ft
Peak RCS Pressure ≤2750 psia
No Loss of Secondary Heat Sink

For sequential CEA bank withdrawals initiated from critical conditions, SAFDL protection (DNBR and LPD) is provide by the CPCs. Transient analysis provides verification that the lead-lag dynamic compensation filters respond conservatively. See Section 1.8 of this enclosure for further analysis. This safety analysis verification along with other conservative CPC input ensures the overall conservatism of the CPC.

The CEA Bank Withdrawal from critical condition events is described in Chapter 15.1.2 of the SAR (Reference 1-1).

Impact of Changes

The RSGs and the proposed TS changes do not result in any changes to key input data for the HFP and HZP sequential CEA Bank Withdrawal events from critical conditions. The core physics, reactivity insertion rate of the CEA bank withdrawals, 3-D power peaks, kinetics parameters, Doppler coefficient and the MTC dominate these events.

For the HFP CEA bank withdrawal, maximum RCS flow has a slightly more conservative effect. The impact of this input is discussed in Section 1.8 of this enclosure as part of the CPC Dynamic Filter Analysis. The increase in minimum RCS flow has no effect on the HFP CEA bank withdrawal as higher RCS flow rates are considered in Section 1.8. An increase in minimum RCS flow has a small beneficial impact on the HZP CEA bank withdrawal.

Analysis Overview

The method used was a comparison of changes in key input parameters between those documented in the SAR versus the new data resulting from the RSGs.

The one key parameter that changed for the CEA Withdrawal from HFP event is the maximum RCS flow range which has increased to account for the RSGs. This is assessed and discussed later in Section 1.8 of this enclosure.

Analysis Results

Since the hot zero power results are not impacted by the proposed TS changes and RSGs, the results are bounded by the SAR. The proposed TS changes do not negatively impact the HFP CEA band withdrawal. However, there is a small impact on the hot full power CEA bank withdrawal due to an increased maximum RCS flow range. This impact is discussed in Section 1.8 of this enclosure.

1.1.3 CEA Misoperation

Summary

The objective of the CEA misoperation event evaluation is to determine the impact of the RSGs for Cycle 15. This section includes those CEA misoperation events resulting from single CEA drops and CEA sub-group drops.

There is no impact due to the proposed TS changes or the RSGs for the CEA misoperation events that result in single CEA or CEA sub-group insertions.

General Description of the Event

A Single CEA Drop is defined as the inadvertent release of a CEA and its insertion into the core. The CEA drive system is the magnetic jack type. An interruption or opening of the electrical circuit of the holding coil would cause the CEA to drop. After the drop of a single CEA, a rapid decrease in power would follow. This is accompanied by a decrease in reactor coolant temperatures and pressure. In the presence of a negative MTC, positive reactivity is added as reactor coolant temperature decreases. Since a power mismatch exists between the secondary and the primary plants, the primary side would try to restore itself to the initial power.

The single CEA drop events are a subset of the AOOs that are analyzed to determine the minimum required thermal margin that must be maintained by the TS Limiting Conditions for Operation (LCO) such that, in conjunction with the RPS, the DNB and centerline-to-melt SAFDLs will not be violated. The required thermal margin is monitored by the Core Operating Limit Supervisory System (COLSS), when in service, and by the operators using CPCs when COLSS is out of service (CPC data is compared to a DNBR limit plot).

The required thermal margins for single CEA withdrawal events, loss of RCS flow events, asymmetric steam generator transient (ASGT) events, CEA drop events, and other AOOs are determined to find the most limiting required thermal margin value for a given ASI and initial power level. The CEA drop events result in changes to the 3-D core power distributions and are not as significant for the purposes of determining COLSS inputs and operating limits.

The TSs allow the plant to maintain the initial power for a defined period of time after a CEA drop. After this initial time period, plant power must be reduced in accordance with the power (in rated power) reduction curves documented in TS 3/4.1.3. During the initial time period, thermal margin protection is provided by the initial margin reserved in the TS LCOs. After the initial period, the power reduction provides additional thermal margin. Further TS actions are applied if the CEA is not realigned within a specified period.

The CEA Subgroup Drop event is defined as an inadvertent release of a CEA subgroup causing it to drop into the core. When CEA Calculators (CEACs) are operable, a penalty factor is applied to the CPC's DNBR and LPD algorithms such that an immediate reactor trip occurs, if needed. When CEACs are inoperable, additional thermal margin must be set aside in the LCOs. The transient response to the CEA Subgroup Drop is similar to that of the Single CEA Drop.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to calculate the CEA misoperation DNB thermal margin requirements that must be reserved in the TS LCOs. This assures that the minimum DNBR for these events does not exceed the DNB SAFDL.

The criterion for the CEA misoperation event is as follows:

$$\text{DNBR} \geq \text{DNB SAFDL}$$

CEA Misoperation events are described in Chapter 15.1.3 of the SAR (Reference 1-1).

Impact of Changes

The proposed TS changes and the RSGs do not result in any change to key input data for the CEA Misoperation events. The core physics, single/sub-group CEA worths and radial power distortion factors, kinetics parameters, Doppler coefficient and MTC dominate these events.

Analysis Overview

The method used in this evaluation performed a comparison of key plant and physics input parameters between those used in the SAR and that of the new input data due to the proposed TS changes, the RSGs, and other plant changes.

Analysis Results

Since the proposed TS changes and the RSGs do not impact the results, the results are bounded by the current analysis.

1.1.4 Control Element Assembly Ejection

Summary

The objective of the CEA ejection event evaluation is to determine the impact of the RSGs and the increase in RCS flow for Cycle 15.

There are no significant impacts due to the RSGs for the CEA ejection events. The only proposed TS change which effects this event is the change to the minimum RCS flow. The proposed increase in minimum RCS flow will have a small beneficial impact on the analysis results.

General Description of the Event

An ejected CEA is assumed to occur due to a complete circumferential break of either the control element drive mechanism (CEDM) housing or the CEDM nozzle on the reactor vessel. The ejection of the CEA results in positive reactivity insertion into the core, which causes local powers and fuel temperatures to increase. The increasing fuel temperature in conjunction with the Doppler fuel temperature coefficient results in negative reactivity insertion into the core. The negative reactivity mitigates the power rise due to the ejected CEA.

After ejection of a CEA, core power rises rapidly. The event proceeds until either a CPC VOPT or a High LPD trip setpoint is reached. The event is terminated when negative reactivity is added due to the insertion of the CEAs following the reactor trip.

Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to review the number of fuel rods that:

experience clad damage, and
contain hot fuel pellets that exceed a fully molten centerline (C_L) condition.

The analysis contains the following criteria:

Clad Damage Total Average Enthalpy ≤200 cal/g, and
Fully Molten C_L Melting Threshold, C_L Enthalpy ≤310 cal/g.

The CEA ejection events for hot full power and hot zero power are described in Chapter 15.1.20 of the SAR (Reference 1-1).

Impact of Changes

The RSGs do not result in any change to key input data for the CEA ejection events. The core physics; ejected CEA worths and 3-D power peaks, kinetics parameters, Doppler coefficient, and MTC dominates these events. The increase in RCS flow was also determined not to have a small beneficial impact on the CEA ejection event.

Analysis Overview

The method used in this evaluation for the CEA ejection events performed a comparison of key plant and physics input parameters between those used in the SAR and that of the new input data due to the RSGs and other plant changes. The key plant and physics input for the CEA ejection events are described in Reference 1-11 (C-E Method for CEA Ejection Analysis).

Analysis Results

Since the results for the high worth CEA ejection events are not impacted by the proposed TS changes and the RSGs, the results are bounded by the current analysis.

1.2 Uncontrolled Boron Dilution Incident

Summary

The objective of the Uncontrolled Boron Dilution incident evaluation is to determine the impact of the proposed TS changes and the RSGs for Cycle 15.

There is no impact due to the proposed TS changes and the RSGs.

General Description of the Event

The Uncontrolled Boron Dilution Event could be a result of improper operator action or a failure in the boric acid make-up flow path that reduces the flow of borated water to the charging pump suction. Either can produce a charging flow boron concentration that is lower than the RCS boron concentration. During operation at power (Modes 1 and 2), an uncontrolled boron dilution adds positive reactivity and can cause an approach to the DNBR and centerline-to-melt (CTM) limits. The CPCs monitor the transient behavior of pertinent safety parameters and will generate a reactor trip if necessary to prevent the DNB and CTM limits from being exceeded. The high pressurizer pressure trip will prevent primary pressure from reaching the RCS pressure upset limit. The RPS trip that is actuated depends on the rate of reactivity addition.

For the subcritical modes (Modes 3 through 6), various alarms/indicators are available to the operator (depending on the mode of operation and plant configuration) to ensure sufficient time is available to respond to an uncontrolled boron dilution event prior to losing SDM. The time required to achieve criticality due to boron dilution is dependent on the initial and critical boron concentrations, the boron reactivity worth, and the rate of dilution.

Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to demonstrate that the SAFDLs are not violated. This is indirectly demonstrated to be satisfied by ensuring that an uncontrolled criticality does not occur within the specified times for operator corrective action.

The criteria for the Uncontrolled Boron Dilution event are the following:

Modes 1-5: No loss of shutdown margin for 15 minutes after operator identification of an unplanned boron dilution.

Mode 6 (Refueling): No loss of shutdown margin for 30 minutes after operator identification of an unplanned boron dilution.

The Uncontrolled Boron Dilution event is described in Chapter 15.1.4 of the SAR (Reference 1-1).

Impact of Changes

The RSGs result in an increase in RCS mass. The core physics parameters of initial boron concentration and inverse boron worth, in combination with TS SDM, and the NSSS RCS mass and assumed charging flow have the major impact on the results of this event. The larger RCS mass results in a longer dilution time constant, which increases the time that the operator has available to perform corrective action.

Analysis Overview

No explicit analysis was performed. The method used in this evaluation was to perform a comparison of key plant and physics input parameters between those used in the SAR and that of the new input data due to the proposed TS changes, the RSGs, and other plant changes.

Analysis Results

Since the proposed TS changes and the RSGs do not impact the results, the results are bounded by the current analysis.

1.3 Loss of Flow Events

1.3.1 Loss of Reactor Coolant Flow Resulting From an Electrical Failure

Summary

The objective of the Loss of Reactor Coolant Flow (LOF) evaluation is to document the impact of the RSGs and Cycle 15 Design changes, which result in the following:

1. an increased maximum initial RCS flow,
2. a slightly more rapid four RCP flow coastdown,
3. a more conservative CPC response time, and
4. the least negative Doppler coefficient becoming less negative.

The impact of the above changes results in a small increase in the LOF DNB required thermal margin. The proposed TS changes in this package have no impact on the loss of reactor coolant flow.

General Description of the Event

The LOF event may result from a loss of electrical power to one or more of the four RCPs. The RCS flow begins to coast down and the RCS temperature and pressure increase simultaneously. This event is mitigated by the CPCs when any one of the four RCPs shaft speed drops below 95% of its nominal speed.

The LOF is analyzed to determine the minimum initial thermal margin that must be maintained by the TS LCOs such that, in conjunction with the RPS, the DNB SAFDL is not violated during the event. This initial margin is monitored by COLSS, when in service, and by the operators using the CPCs when COLSS is out of service (CPC data is compared to a DNBR limit plot).

The principal process variables that determine thermal margin to DNB in the core are monitored by the COLSS. The COLSS computes a power operating limit that ensures that the thermal margin available in the core is equal to or greater than that needed to maintain the minimum DNBR greater than the DNBR limit.

The action of the RPS and insertion of the CEAs mitigate the decrease in DNB thermal margin due to the four RCP flow coastdown. This results in the minimum DNBR (greater than the DNB SAFDL) occurring in less than four seconds after the initiation of the event.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to calculate the LOF DNB thermal margin requirements that must be reserved in the TS LCOs. This assures that the minimum DNBR for the event does not exceed the DNB SAFDL.

The criterion for the LOF event is the following:

DNBR $\geq$ DNB SAFDL

The Loss of Reactor Coolant Flow Resulting From an Electrical Failure event is described in Chapter 15.1.5 of the SAR (Reference 1-1).

Impact of Changes

The RSGs results in a higher maximum initial RCS flow and lower steam generator primary side flow resistance. The lower steam generator primary side flow resistance results in essentially the same RCP flow coastdown upon electrical failure; however, more conservative initial conditions have been assumed resulting in a slightly more rapid coastdown. Both of these changes result in a slightly higher DNB thermal margin requirement (or, lower event DNBR values in the absence of increased thermal margin).

A small increase in the CPC response time is being considered as part of the Cycle 15 and RSG design. This slight increase in CPC response time delays the time that the CEAs enter the core to mitigate the thermal margin degradation.

The least negative Doppler coefficient becoming less negative results in a higher power/heat flux increase during the event. A less negative Doppler coefficient is being considered as part of the Cycle 15 and RSG design.

Analysis Overview

The current LOF event analysis was analyzed using the HERMITE code. The HERMITE code described in Reference 1-4 does not employ a steam generator model, but does use as an input the four RCP flow coastdown data. The effect of the RSGs was modeled by supplying the core flow rate as a function of time as input data to model the four RCP flow coastdown.

The method used in this evaluation performed a comparison of key plant and physics input parameters between those used in the current analysis and that of the new input data due to the RSGs and other plant changes. The key input data that has changed is listed below.

The evaluation was carried out in the following steps to determine the impact of key plant and physic input data changes:

1. The RCP coastdown data for the loss of flow event was generated using the CENTS code (Reference 1-2). The use of the CENTS code is consistent with the current analysis method.

2. The impact of a 0.15% decrease in four pump RCS flow for the first four seconds was assessed. Table 1.3.1-1 documents the flow coastdown for the first ten seconds.

3. The increase in initial maximum RCS flow assumption from 355,200 gpm to 386,400 gpm was assessed.

4. An increase in CPC response time from 0.3 seconds to 0.4 seconds was assessed.

5. The least negative Doppler coefficient becoming less negative, changing from -0.00131 $\Delta\rho/K$ to -0.00128 $\Delta\rho/K$ was assessed.

Analysis Results

The HERMITE code was not used. Instead, an engineering evaluation of changes in key input data was employed to assess the impact on the LOF event. Based on previous sensitivity studies, the required thermal margin increase was conservatively calculated based on the above input data changes.

The decrease in RCS flow due to a slightly more adverse four RCP flow coastdown during the first four seconds was 0.15%. The change resulted in an increase in the required thermal margin of less than 0.15%.

The impact of the increase in maximum initial RCS flow from 355,200 gpm to 386,400 gpm also resulted in an increase in required thermal margin of 0.2%.

The increase in CPC response time results in a 0.55% increase in required thermal margin.

The least negative Doppler coefficient becoming less negative has a negligible impact on the LOF event results.

The overall impact on the required thermal margin increase is less than 1%. Thus, the minimum DNBR in the current analysis was decreased from 1.29 to no less than 1.277, but remains above the DNB SAFDL value of 1.25. Table 1.3.1-2 provides a modified sequence of events from the current analysis.

Although the changes delineated above result in a slight increase in the thermal margin required for the LOF event, the minimum thermal margin reserved by COLSS and the DNBR limit plot (utilized when COLSS is out-of-service) will be updated for Cycle 15, if necessary, and set equal to or greater than the maximum thermal margin degradation observed during a LOF event. Therefore, the CPC trip on pump low speed in conjunction with the initial margin reserved in COLSS is sufficient to protect the DNB SAFDL from any set of initial conditions.

1.3.2 Loss of Reactor Coolant Flow Resulting From a Pump Shaft Seizure

Summary

The objective of the Seized Shaft evaluation is to document the impact of the RSGs, the proposed TS changes, and radiological dose impacts which result in the following:

1. an increased maximum initial RCS flow,
2. a slightly smaller 3-pump asymptotic flow fraction following the seizure of one RCP shaft,
3. a larger RCS and steam generator inventory (affects radiological doses),
4. an increase in rated power to 3026 MWt (for radiological doses only), and
5. a change in radiological dose methodology.

The impact of the above changes results in an increase in the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ) radiological doses. Additionally the changes in the methods presented in Section 1.0.4 contribute to larger doses than those currently in the SAR, which are conservatively concluded to be an unreviewed safety question (USQ) determination. The proposed TS changes do not have a significant impact on the shaft seizure analysis.

General Description of the Events

The Seized Shaft event is analyzed to determine the expected number of fuel pins in DNB due to a reduction from four-pump to three-pump flow. The event is initiated from the minimum initial thermal margin that must be maintained by the TS LCOs. From the number of fuel pins in DNB, the radiological dose values can be determined.

The Seized Shaft event may result from a mechanical failure of one of the RCP shafts. Following the shaft seizure, the core flowrate rapidly decreases to the asymptotic three RCP flowrate. The reduction in RCS flow may result in some fuel pins experiencing DNB. This event is mitigated either by the CPC low DNBR trip or by a CPC RCP shaft speed trip. The reactor trip produces an automatic turbine trip.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine the seized shaft calculated fuel failures and the corresponding EAB (2 hour) and LPZ (8 hour) radiological doses.

The criteria for the seized shaft event are:

EAB Doses (2 hour) are less than 10CFR100 limits.

LPZ Doses (8 hour) are less than 10CFR100 limits.

The Loss of Reactor Coolant Flow Resulting from a Pump Shaft Seizure event is described in Chapter 15.1.5 of the SAR (Reference 1-1).

Impact of Changes

The impact of the RSGs results in a higher maximum initial RCS flow, lower steam generator primary side flow resistance, and larger primary and steam generator fluid masses. The lower steam generator primary side flow resistance results in a lower three-pump asymptotic flow fraction. This factor results in higher DNB thermal margin requirements (or, lower event DNBR values in the absence of increased required thermal margin). The increase in RCS and steam generator masses results in slightly larger steam releases, which increase the radiological doses.

The increase in core power results in an increase in the radiological dose results.

The change in radiological dose methodology results in an increase in the EAB and LPZ whole body dose. For this evaluation, the reported fuel failure for the radiological doses are back calculated from the 10CFR100 dose criteria.

Analysis Overview

The RCS flow coastdown data for the seized rotor event was generated using the CENTS code. The use of the CENTS code is consistent with the current analysis method.

The method of the current analysis for the seized rotor assumes an instantaneous drop from the initial flow rate to the reduced three-pump steady-state flow fraction. Only the final asymptotic three-pump flow fraction is important and not the actual RCS flow coastdown.

The method used is a comparison of key input parameters between those documented in the current analysis and that of the new data due for the RSGs.

The evaluation was carried out in the following steps to determine the impact of key plant and physic input data changes:

1. The RCS flow coastdown data for the seized rotor flow event was generated using the CENTS code. A slightly lower final asymptotic three-pump RCS flow value of 0.6% was assessed.

2. The increase in initial maximum RCS flow limit from 355,200 gpm to 386,400 gpm was assessed.

3. The increase in RCS and steam generator inventories was assessed using the new radiological dose method.

The analysis input and assumptions used in the calculation of the radiological dose releases for the seized shaft event are discussed in Section 1.0.5 of this enclosure and have been incorporated in this analysis with the following clarifications:

1. The condenser is assumed unavailable for cooldown (this is a conservative assumption with respect to the current method defined in the SAR). Thus, the entire cooldown was performed by dumping steam to the atmosphere from the steam generators.

2. The radiological doses were conservatively calculated at a higher rated power of 3026 MWt (3087 MWt including uncertainties) and parametric in 0.5% fuel failure intervals.

3. An RCS primary to secondary leakage rate of 150 gpd per steam generator was assumed consistent with the TS limit on allowable leakage. No increase in leakage (to 720 gpd or 0.5 gpm) was considered for this event as the steam generators are not predicted to depressurize.

Analysis Results

No explicit cases were analyzed. An engineering evaluation of changes in key input data has been employed to assess the impact on the seized shaft event.

The difference in the three-pump asymptotic percentage flow value was lower by 0.6%. This difference has a small impact on the calculated fuel failure for the seized rotor event. The fuel failure calculation was modified to include this small change.

The increase in maximum initial RCS flow was determined to be bounded by the results of the minimum initial RCS flow results in the current analysis. The current analysis is based on the current minimum TS flow rate, hence, the proposed increase in the minimum RCS flow rate has a small beneficial impact on the analysis result.

The effect of the increase in RCS and steam generator inventories was combined with the 3026 MWt rated power physics radiological dose data to calculate the doses in fuel failure increments of 0.5%. The results of the analysis demonstrate that the EAB and LPZ radiological doses remain within a small fraction (10%) of 10CFR100 limits up to 14% fuel failure. The calculated results for 14% fuel failure are presented in Table 1.3.2-1.

1.4 RCS Heatup Events

1.4.1 Loss Of External Load and/or Turbine Trip

Summary

The objective of Loss of External Load and/or Turbine Trip event analysis is to document the impact of

1. the RSGs,
2. a change in the Low Steam Generator Level Trip setpoint and an increase in analytical response time,
3. a reduction in the High Pressurizer Pressure Trip setpoint and reduced analytical response time,
4. an increase in rated power to 3026 MWt,
5. an increase in RCS flow,
6. a change in the High Linear Power Trip setpoint with a prescribed number of MSSVs out of service, and
7. address offsite releases.

The impact of the above changes results in no violation of maximum RCS and steam generator pressure limits. As part of this analysis, a calculation/verification of the High Linear Power Trip setpoint with different number(s) of MSSVs (1, 2 or 3 banks) inoperable is performed. The MSSV inoperable analysis results in lower High Linear Power Trip setpoints when more than one MSSV on each header is out-of-service. Additionally, a new case has been added to TS Table 3.7-1 which allows an individual valve to be taken out of service on a MTC-dependent High Linear Power Trip setpoint. This MTC-dependent High Linear Power Trip setpoint approach was also applied to the one bank of MSSVs out of service case.

General Description of the Event

A loss of external load and/or turbine trip results in a reduction of steam flow from the steam generators to the turbine generator. Cessation of steam flow to the turbine generators occurs because of closure of the turbine stop valves or turbine control valves. The cause of the loss of load may be abnormal events in the electrical distribution network or turbine trip.

The bounding event considered is a Loss of Load (LOL) event initiated by a turbine trip without a simultaneous reactor trip and assuming the Steam Dump and Bypass Control System (SDBCS) is inoperable. If the turbine trip was caused by a total Loss of Condenser Vacuum (LOCV), the main feedwater pump steam turbines would also trip. Therefore, a LOL concurrent with a loss of feed was analyzed to cover these events.

Closure of the turbine stop valves and coastdown of the main feedwater pumps causes the primary and secondary temperatures and pressures to increase rapidly. The PSVs and the MSSVs limit the pressure increase in the primary and secondary systems following reactor trip.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the peak RCS pressure remains below its criterion.

The criteria for the LOL/LOCV event are:

Peak RCS Pressure $\leq$2750 psia
Peak Secondary System Pressure $\leq$ 1210 psia

The Loss of External Load and/or Turbine Trip / Loss of Condenser Vacuum event is described in Chapter 15.1.7 of the SAR (Reference 3.6-1).

This event also is used to determine the High Linear Power Trip setpoint with a prescribed number of MSSVs inoperable such that peak steam generator pressure remains below the criterion.

Impact of Changes

The peak RCS and steam generator pressures are impacted by the replacement steam generator characteristics. Changes in heat transfer area, steam generator pressures, steam generator inventories, and instrument tap spans impact how the event proceeds. The timing of safety systems operation during the event depends on which parameter is dominant (e.g., whether the MSSVs open before or after the High Pressurizer Pressure Trip is generated).

All of the above in combination with the initial core inlet temperature impact the response of the steam generator pressure. Higher initial steam generator pressures and those changes that result in a more rapid increase in steam generator pressure result in the MSSVs opening sooner.

The increase in RCS flow results in a larger peak RCS pressure and a very slightly smaller steam generator pressure.

The decrease in the High Pressurizer Pressure Trip analytical setpoint and response time results in an earlier reactor trip. As indicated in Section 1.0.1 this lower analytical setpoint still supports the current TS setpoint of 2362 psia. This lower analytical setpoint has been justified due to normal environment conditions. This RPS change in combination with the RSGs offsets the increase in RCS flow and improves the peak RCS pressure results.

The increase in rated power results in higher RCS and secondary energy, which makes both RCS and steam generator pressure increase due to the loss of load and concurrent loss of feedwater. The RSGs and decrease in the High Pressurizer Pressure Trip analytical setpoint and response time offset most of the impact on the peak RCS pressure increase. The increase in rated power accentuates the increase in peak secondary pressure.

For the intermediate power levels with MSSVs inoperable, there are two primary RPS trips available; the High Pressurizer Pressure Trip and the Low Steam Generator Level Trip. These events do not challenge the RCS pressure criterion, but do challenge the steam generator pressure criterion. As stated earlier, opening of the MSSVs may delay the High Pressurizer Pressure Trip. Hence, the primary RPS trip becomes the Low Steam Generator Level Trip.

Since the RSGs have a different instrument tap span and these affect the initial steam generator masses and the time in which a Low Steam Generator Level Trip is reached, the intermediate powers with some number of MSSVs inoperable are evaluated. Thus, the changes in Low Steam Generator Level Trip analytical setpoints and response time may result in a longer time to reactor trip, which would result in more residual stored energy that must be released after reactor trip. This typically results in higher steam generator pressures. There is no impact on the RCS pressure since if it were approaching its criterion, the High Pressurizer Pressure Trip would have generated a reactor trip. If the Low Steam Generator Level Trip is the first RPS trip to occur, typically the result will be that the steam generator pressure criterion may be challenged. Typically the Low Steam Generator Level Trip is the primary RPS trip to occur for initial power levels less than hot full power.

Analysis Overview

The methodology used in this analysis was the same as that used for the current analysis. This analysis has utilized the CENTS computer code for the transient analysis simulation.

Input parameters from Table 1.4.1-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The BOC Doppler curve in Figure 1.0.2-2 was assumed.

2. A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 of this enclosure was assumed.

3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. CEA worth of -5.0% $\Delta\rho$ was conservatively assumed.

4. A High Pressurizer Pressure Trip setpoint of 2392 psia and a response time of 0.65 seconds were assumed.

5. An MSSV tolerance of +3% was conservatively assumed.

6. An initial core power of 3087 MWt, based on a rated power of 3026 MWt and a 2% uncertainty, was assumed.

7. A MTC of 0.0×10^{-4} $\Delta\rho/°F$ at HFP was assumed. This is conservative to the BOC MTC of -0.2×10^{-4} $\Delta\rho/°F$ in Figure 1.0.2-1 of this enclosure.

8. The minimum HFP core inlet temperature of 540° F was assumed.

9. A PSV tolerance of 3.2% was conservatively assumed.

10. Parametric analyses were performed on the number of plugged U-tubes per steam generator. It was determined that zero plugged U-tubes per steam generator was limiting.

11. Installation of the RSGs was assumed.

12. A maximum RCS flow of 386,400 gpm was assumed.

13. The PSV flow was adjusted by the Napier correction.

A similar analysis was performed to determine a conservative peak secondary pressure, as the input assumptions described above and denoted in Table 1.4.1-1 are established to ensure a peak primary pressure. This second analysis is effectively the same as the peak primary analysis except the input assumptions delineated above are adjusted to ensure a conservative peak secondary pressure.

For the inoperable MSSV bank analysis (2 or 3 banks), the following assumptions either compliment or replace the above analysis inputs.

1. The EOC Doppler curve in Figure 1.0.2-2 of this enclosure was assumed.

2. An EOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 of this enclosure was assumed.

3. The most positive BOC MTC for a given initial power from Figure 1.0.2-1 was assumed.

4. The maximum core inlet temperature of 556.7° F was assumed.

5. A minimum RCS flow of 315,560 gpm was assumed.

6. Zero plugged U-tubes per steam generator was assumed.

7. A Low Steam Generator Level Trip of 9% of NR and a response time of 1.3 seconds was assumed.

8. Initial core powers were based on a HFP value of 3026 MWt.

9. Initial steam generator pressures were greater than 1000 psia based on the initial power level assumed.

10. For the 2 or 3 inoperable MSSVs per steam line, the values with the lowest opening setpoint(s) were assumed to be inoperable.

A final set of cases assuming only one individual MSSV inoperable and 1 MSSV bank inoperable were assessed. These cases were performed consistent with the other MSSV inoperable cases except a higher High Linear Power Trip setpoint was determined based on MTC. An MTC versus EFPD correlation is currently presented in the Core Operating Limits Report, which is effectively that presented in Figure 1.0.2-1 of this enclosure. The MTC value will be converted to EFPD based on this correlation. A final figure for Cycle 15 will be completed as part of the reload effort.

Analysis Results

The peak RCS and steam generator pressures (2688 psia and 1180 psia, respectively) remained well below the respective criterion of 2750 psia and 1210 psia. The NSSS and RPS responses for the LOCV event are shown in Table 1.4.1-2 and in Figures 1.4.1-1 through 1.4.1-5. The results of the second analysis to determine peak secondary pressure resulted in a steam generator dome pressure of 1209 psia, which remained below the 1210 psia criterion.

The maximum steam generator pressure that occurred for the MSSV inoperable cases was less than 1208 psia. Table 1.4.1-3 lists the maximum allowed initial power versus the prescribed number of MSSVs inoperable.

The combination of the replacement steam generators, an increase in rated power, and the change of the Low Steam Generator Level Trip analytical setpoint and response time resulted in peak RCS and steam generator pressures within acceptance criteria.

No radiological dose calculation was performed for this event. As indicated in Section 1.0.5 of this enclosure, doses for this and other AOOs are deemed acceptable due to the bounding nature of the MSLB and FWLB doses.

1.4.2 Loss of Normal Feedwater Flow

Summary

The objective of the Loss of Normal Feedwater Flow event analysis is to document the impact of:

1. the RSGs,
2. an increase in the Low Steam Generator Level Trip analytical setpoint and response time,
3. an increase in the EFAS analytical setpoint,
4. an increase in rated power to 3026 MWt,
5. the increase in the most negative MTC (more negative), and
6. an increase in RCS flow.

The impact of the above changes results in no loss of secondary heat sink.

General Description of the Event

The loss of normal feedwater (LOFW) event is a reduction of the main feedwater flow to the steam generators without a corresponding reduction of the steam flow from the steam generators. The result of this flow mismatch is a reduction of the steam generators' water inventory as well as a subsequent primary side coolant heatup. The loss of feedwater event can result from either the loss of both main feedwater pumps or the loss of four condensate pumps.

The RPS and the ESFAS provide protection against the loss of secondary heat sink via the Steam Generator Low Level Trip and the automatic initiation of the EFW System. Over pressure protection is also provided by the High Pressurizer Pressure Trip, the PSVs, the SDBCS, and the MSSVs. The opening of the SDBCS valves and the MSSVs maximize the reduction of the steam generator water inventory. Shortly after EFW enters the steam generators, the decrease in steam generator inventory is terminated.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to assure that the secondary heat sink is maintained.

The criterion for the LOFW event is:

Steam Generator heat removal capability maintained.

The LOFW event is described in Chapter 15.1.8 of the SAR (Reference 3.6-1).

Impact of Changes

The RSGs result in higher steam generator heat transfer area and pressures. Higher steam generator heat transfer area and pressures result in a faster depletion of steam generator inventory during the post-trip event. Maximizing the post-trip liquid inventory depletion challenges the EFW System.

The increase in rated power would result in higher residual heat that must be removed during the post-trip event. Since the EFW system remains essentially the same for the increase in rated power as for the current power, there is a greater steam generator liquid decrease prior to post-trip recovery.

The increase in the Low Steam Generator Level Trip and EFW actuation analytical setpoints was required to minimize the decrease in the liquid inventory available for post-trip cooling at the time of trip and EFW System actuation. The original steam generators assumed a Low Steam Generator Level Trip and EFW System actuation analysis setpoint of 5% of narrow range indication. An analysis setpoint of 9% has been used here. The uncertainty , which established the difference between the analysis and equipment setpoint value, is based on the normal environment since there is no high-energy pipe break. As indicated in Section 1.0.1 of this enclosure, the TS setpoint has been lowered even though the analysis value has been raised. This is due to the more detailed break down of instrument uncertainties. The Low Steam Generator Level Trip response times increased from 0.9 seconds, to 1.3 seconds.

During the early portion of the event and prior to opening of the SDBCS valves, the LOFW event behaves like a heat-up event. After the SDBCS valves open, the LOFW behaves like an overcooling event. During this portion of the event, a negative MTC enhances the RCS heat-up prior to reactor trip.

For this event, the minimum RCS flow is conservative. The increase in the minimum RCS flow results in a slight benefit since it reduces the temperature difference across the core, which reduces the primary-to-secondary heat transfer. This results in a slightly slower loss of steam generator inventory.

Analysis Overview

The methodology used in this analysis is the same as that used for the current analysis. This analysis has utilized the CENTS computer code for the transient analysis simulation.

Input parameters from Table 1.4.2-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The EOC Doppler curve in Figure 1.0.2-2 was assumed.
2. A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 of this enclosure was assumed.
3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. CEA worth of –5.0 % $\Delta\rho$ was conservatively assumed.
4. An EFW analytical response time of 97.4 seconds was assumed. EFW flow was determined based on steam generator pressure.
5. An MSSV tolerance of -3.5% was conservatively assumed.
6. An initial core power of 3087 MWt, based on a rated power of 3026 MWt and a 2% uncertainty, was assumed.
7. The most negative MTC of -3.8×10^{-4} $\Delta\rho/°F$ was assumed.
8. Low Steam Generator Level Trip and EFAS analytical setpoints of 9% of narrow range indication were assumed.
9. Installation of the RSGs was assumed.
10. An RCS flow of 315,560 gpm was assumed.
11. The PSV flow was adjusted by the Napier correction.

Analysis Results

The minimum steam generator inventory occurred at 212 seconds for steam generator A (RCS loop with pressurizer) and 288 seconds for steam generator B.

The NSSS, RPS, and EFW system responses for the LOFW event are shown in Table 1.4.2-2 and in Figures 1.4.2-1 through 1.4.2-5.

The combination of the replacement steam generators, an increase in rated power, and the change in Low Steam Generator Level Trip and EFAS setpoints did not result in steam generator dryout. Since a minimum steam generator liquid inventory was maintained, there was no loss of secondary heat sink.

1.4.3 Loss of All Normal and Preferred AC Power to the Station Auxiliaries

Summary

The objective of the Loss of All Normal and Preferred AC Power to the Station Auxiliaries evaluation is to determine the impact of the RSGs. This objective was achieved by identifying other Design Basis Events (DBEs) with the same acceptance criteria that have consequences that bound those of the Loss of Normal and Preferred AC Power (LOAC) event.

General Description of the Event

The LOAC event is defined as a complete loss of preferred (off-site) AC electrical power and a concurrent turbine trip. As a result, electrical power would be unavailable for certain of the station auxiliaries such as the RCPs, the steam generator main feedwater pumps, and the main circulating water pumps. Under such circumstances, the plant would experience a simultaneous loss of load, loss of feedwater flow, and a loss of forced reactor coolant flow.

The LOAC event is followed by automatic startup of the EDGs. The power output of the emergency diesel generators is sufficient to supply electrical power to all engineered safety features and to provide the capability of maintaining the plant in a safe shutdown condition.

The LOAC event is primarily analyzed to determine the radiological dose releases during the event. In addition, the peak primary and secondary pressures and minimum steam generator liquid inventory are reviewed.

Purpose of Analysis and Acceptance Criteria

The criteria for the LOAC event are the following:

DNBR $\geq$ DNB SAFDL
Peak RCS Pressure $\leq$ 2750 psia
Radiological Doses acceptable

The LOAC is described in Chapter 15.1.9 of the SAR (Reference 1-1).

Impact of Changes

The impact of the changes would be encompassed by those for the Loss of Reactor Coolant Flow Resulting from an Electrical Failure (Section 1.3.1), the Loss of External Load and/or Turbine Trip (Section 1.4.1), and the Feedwater Line Break event (Section 1.4.4).

Analysis Overview

The method for evaluation is to identify other DBEs that have behavior similar to the LOAC event, with the same acceptance criteria, and result in more adverse consequences.

Analysis Results

An evaluation of the LOAC has verified that:

1. The LOAC event's minimum DNB SAFDL is bounded by the Loss of Forced Reactor Coolant Flow event (Section 1.3.1).

2. The LOAC event's peak RCS and steam generator pressures are bounded by the Loss of External Load/Turbine Trip event (Section 1.4.1).

3. The LOAC event's radiological doses for the EAB and LPZ are acceptable as discussed in Section 1.0.5 due to the bounding nature of the MSLB and FWLB doses.

Based on this evaluation, no subsequent LOAC analyses have been performed and none need be performed for Cycle 15 and for power uprate as well, since the results of the three bounding events listed meet the acceptance criteria for the respective event.

1.4.4 Feedwater Line Break Accident with or without concurrent Loss Of AC Power

Summary

The objective of Feedwater Line Break (FWLB) with or without concurrent loss of normal AC power event analysis is to document the impact of:

1. the RSGs,
2. an increase in the Low Steam Generator Level Trip analytical setpoint and response time,
3. a reduction in the EFAS setpoint,
4. an increase in rated power to 3026 MWt (dose calculation only),
5. a reduction in the High Pressurizer Pressure Trip analytical setpoint and reduced response time,
6. a change in RPS and ESFAS uncertainties,
7. an increase in RCS flow,
8. a longer MSIV stroke time,
9. an increase in the Low Steam Generator Pressure Trip and MSIS actuation setpoint,
10. an analysis method change in calculation of trip time,
11. a larger RCS and secondary inventory, and
12. a change in radiological dose methodology.

The impact of the above changes results in no violation of RCS and steam generator pressure criteria and no pressurizer overfill condition. Due to changes in the radiological dose methods, larger doses than those currently in the SAR were calculated, which are conservatively concluded to be a USQ.

General Description of the Event

A FWLB event is defined as the rupture of a main feedwater pipe during plant operation. If the feedwater line breaks upstream of the feedwater check valves, steam generator blowdown is prevented by the closure of the check valves. If the break occurs between the steam generator and the check valves, blowdown of that steam generator continues until it empties. Blowdown of the unaffected steam generator is prevented by the action of the feedline check valves and, via MSIS actuation, closure of the MSIVs.

In a postulated FWLB accident, a reactor trip occurs due to one of the following RPS signals:

1. Low Steam Generator Level Trip

2. High Pressurizer Pressure Trip

3. Low Steam Generator Pressure Trip.

Additional reactor trip signals that may respond to the transient are the CPC Low DNBR Trip or the High Containment Pressure Trip.

A loss of offsite AC power is postulated for this transient.

The ESFAS logic initiates EFW to the intact steam generator upon receiving an EFAS signal after the appropriate time delay has been satisfied. Prior to the MSIS condition, EFW flow to the ruptured steam generator is assumed to flow directly out of the break. Due to the EFW header to the steam generators being cross-tied, flow to the intact steam generator may not begin until the ruptured steam generator is isolated. The steam generators are isolated after trip by the MSIS signal. After the MSIS signal due to low steam generator pressure is received, EFW flow to the affected steam generator ceases and all available EFW flow is directed to the intact steam generator (assuming the pressure of the intact steam generator is at least 90 psi greater than that of the affected steam generator).

The opening of the PSVs and the MSSVs mitigates over-pressurization of the RCS and steam generators.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that for the limiting FWLB event, the peak RCS pressure remains below its criterion and the pressurizer does not over fill.

The criteria for the FWLB event are:

Peak RCS Pressure ≤2750 psia
Peak Secondary System Pressure ≤ 1210 psia
Pressurizer does not go solid
Radiological Doses ≤ small fraction (10%) of 10CFR100 limits

The FWLB event is described in Chapter 15.1.14.2 of the SAR (Reference 1-1).

Impact of Changes

The combination of the RSGs and the increase in rated thermal power produces a higher performance regime which requires reanalysis to determine if RCS peak pressure (and long term pressurizer fill) is adversely affected during the FWLB event.

The RSGs result in larger steam generator heat transfer area and in higher steam generator pressures. Higher steam generator heat transfer area and pressures result in a faster depletion of steam generator inventory during the post-trip event. Maximizing the post-trip liquid inventory depletion challenges the EFW system.

The increase in the Low Steam Generator Level Trip analytical setpoint was credited to minimize the decrease in the liquid inventory available for post-trip cooling at the time of trip. The Low Steam Generator Level Trip analytical response time increased from 0.9 seconds to 1.3 seconds. Abnormal environmental instrument uncertainties were used for the Low Steam Generator Level Trip setpoint determination since this event is a high-energy pipe break. The Low Steam Generator Level Trip needs only to function until the High Containment Pressure Trip (with a reduced response time of 1.2 seconds) would occur. Hence, the uncertainties need not be based on the containment design limits but on environmental conditions at the time that the High Containment Pressure Trip would occur.

The EFAS setpoint was decreased to aid in lowering the Low Steam Generator Level Trip equipment setpoint. A lower setpoint in combination with the RSG will help avoid EFW actuation on uncomplicated reactor trips. The original steam generators assumed a Low Steam Generator Level Trip and EFAS analysis setpoint of 5% of narrow range indication.

The uncertainty applied to the difference between the analysis and equipment setpoint values is based on the harsh environment since this event is a high-energy pipe break. EFAS functions must maintain flow until operator control is established following a high energy pipe break.

The High Pressurizer Pressure Trip employed the harsh environment uncertainty as the difference between the analysis and equipment setpoint since this event is a high-energy pipe break. The overall uncertainty was revisited and some of the conservatism in the analytical setpoint was removed. Thus, the High Pressurizer Pressure Trip analytical setpoint decreased from 2422 psia to 2415 psia. The analytical response time was also reduced from its previous value of 0.9 seconds to 0.65 seconds, which remains above the theoretical response time and historical test data.

A change in analysis methodology has been incorporated into the FWLB event. Previously, a parametric analysis was performed on FWLB size and the affected SG level to obtain a simultaneous reactor trip on High Pressurizer Pressure, Low Steam Generator Level on the intact steam generator, and dry-out of the affected steam generator. This was an overly conservative method to have one steam generator reach the low level setpoint at the same time the affected steam generator would dry-out. To accomplish this, often different initial steam generator levels were assumed. Controlling to different steam generator levels is an overly conservative assumption. For the new method, the limiting break size is determined by a parametric analysis that is performed on initial steam generator level and pressurizer pressure to obtain a simultaneous High Pressurizer Pressure Trip and Low Steam Generator Level Trip on the intact steam generator. Both steam generators are assumed to begin at the same initial level.

The increase in core power and RCS / steam generator masses results in slightly larger steam releases. The larger steam releases and the change in radiological dose methodology results in an increase in the EAB and LPZ whole body dose.

Analysis Overview

The methodology used in this analysis has changed slightly from that used in the analysis of record. The previous method determined the limiting FWLB area by combining a simultaneous High Pressurizer Pressure Trip and Low Steam Generator Level Trip on the intact steam generator with a concurrent emptying of the affected steam generator. This required an overly conservative large initial mass difference between the two steam generators. The new method assumes both steam generators are at the same initial mass level. The limiting FWLB area is calculated based on a simultaneous High Pressurizer Pressure Trip and Low Steam Generator Level Trip on the intact steam generator. This is still considered a very conservative approach as no credit is taken for the low level trip in the affected steam generator and the fluid discharge through the break was assumed to be saturated liquid until the affected generator empties.

This analysis has utilized the CENTS computer code for the transient analysis simulation.

Input parameters from Table 1.4.4-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The BOC Doppler curve in Figure 1.0.2-2 was assumed.

2. A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 of this enclosure was assumed.

3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. The curve is consistent with that used in most analyses versus a curve associated with a +0.6 ASI as was used for the Cycle 13 analysis. A CEA worth of -5.0% $\Delta\rho$ was conservatively assumed.

4. The feedwater line break analyzed was assumed to occur during hot full power operation with a loss of offsite power at the time that the trip breakers opened. With a loss of offsite power the turbine stop valves are assumed to close, RCPs begin to coast down, and the pressurizer control systems are lost.

5. The initial steam generator liquid inventory for both steam generators was assumed to be 178,500 lbm.

6. A parametric analysis was performed to determine the FWLB area (0.1798 ft^2) such that a simultaneous trip occurred on High Pressurizer Pressure and Low Steam Generator Level of the intact steam generator. A High Pressurizer Pressure Trip analytical setpoint of 2415 psia with a delay time of 0.65 seconds was assumed. A Low Steam Generator Level Trip analytical setpoint of 6% of narrow range indication with a 1.3 second response time was assumed. This is different than the previous analysis which assumed a concurrent emptying of the affected steam generator. The analytical trip setpoints for the High Pressurizer Pressure Trip conservatively assumes a harsh environment uncertainty and the Low Steam Generator Level Trip assumes an abnormal environment uncertainty.

7. Only EFW flow from one EFW pump was credited to the steam generator with the intact feedwater line. A conservative EFW flow analytical actuation setpoint of 0% of narrow range indication was assumed with a delay time of 112.4 seconds. The uncertainty assumed an EFW flow actuation setpoint based on a harsh environment uncertainty. The time of EFW flow delivery to this generator was based on the maximum of:

   a) the time to receive an EFAS with a delay period that allows the EFW pump to accelerate, or

   b) the time to receive a MSIS with a delay period that allows EFW flow to the affected steam generator to be isolated, or

   c) the time the steam generator ΔP setpoint is reached with a delay period that allows EFW flow to the intact steam generator to be re-initiated.

Isolation of EFW to the affected steam generator is based on the EFW valve isolation time of 36.4 seconds. EFW flow rate to the intact steam generator is dependent on steam generator pressure.

8. A MSIS analytical setpoint of 658 psia was assumed with a 1.4 second response time, a 3.5 second MSIV closure time, and a 35 second EFW isolation valve stroke time. A high ΔP analytical setpoint of 220 psid was assumed with a 1.4 second response time and a 35 second EFW isolation valve stroke time.

9. A conservatively small value for the fuel gap heat transfer coefficient was assumed corresponding to BOC.

10. A MSSV lift tolerance of +3% and PSV lift tolerance of +3.2% were assumed.

11. An initial core power of 2900 MWt, based on a rated power of 2815 MWt and a 3% uncertainty, was assumed.

12. The BOC MTC of -0.2×10^{-4} $\Delta\rho/°F$ was assumed.

13. Assuming equilibrium core conditions maximized decay heat.

14. The analysis considered plugged U-tubes between zero and 10% plugged range per steam generator, with zero percent being conservative.

15. Installation of the RSGs was assumed.

16. A minimum RCS flow of 315,560 gpm was assumed.

17. An initial steam generator pressure of 1000 psia was assumed.

18. The PSV flow was adjusted by the Napier correction.

19. Steam generator full heat transfer area is conservatively assumed down to 19,000 lbm (liquid mass). At 19,000 lbm, the steam generator heat transfer is assumed to ramp linearly to zero at 2000 lbm.

The analysis input and assumptions used in the calculation of the radiological dose releases for the FWLB event are discussed in Section 1.0.5 of this enclosure and have been incorporated in this analysis with the following clarifications:

1. The condenser is assumed unavailable for cooldown due to the loss of offsite power. Thus, the entire cooldown was performed by dumping steam to the atmosphere from the steam generators.

2. Because of the locations of the feedwater check valves, only inside containment FWLBs are considered. This prevents direct release of the inventory from the affected steam generator. However, no credit was taken for hold-up in containment.

3. Due to the tremendous loss of feedwater associated with the event, there is a possibility that both steam generators could reach dry-out. Thus, the analysis conservatively assumed a decontamination factor of 1.0 for both steam generators when steaming the plant.

Analysis Results

The peak RCS and steam generator pressures remained below the respective criteria of 2750 psia and 1210 psia, and the pressurizer did not fill solid with liquid.

The NSSS, RPS, and EFW system responses for the FWLB with loss of AC power on turbine trip event are shown in Table 1.4.4-2 and in Figures 1.4.4-1 through 1.4.4-5.

The combination of the replacement steam generators, an increase in minimum RCS flow, the change in the analytical Low Steam Generator Level Trip and EFAS setpoints, and the change in the analytical MSIS setpoint did not result in the RCS and steam generator pressures exceeding criteria and a pressurizer over-fill did not occur.

The radiological doses for the EAB and LPZ are less than a small fraction of the 10CFR100 limits of 30 Rem for the thyroid and 2.5 Rem for whole body. The calculated results for all doses are presented in Table 1.4.4-3.

1.5 RCS Overcooling Events

1.5.1 Excess Heat Removal due to Feedwater System Malfunction

Summary

The objective of Excess Heat Removal due to Feedwater System Malfunction event analysis is to document the impact of:

1. the RSGs,
2. credit for the CPC VOPT,
3. an increase in rated power to 3026 MWt, and
4. the increase in the most negative MTC (more negative).

The impact of the above changes results in no violation of the SAFDLs and is valid for both Cycle 15 and the increase in rated power to 3026 MWt.

The only proposed TS change that has an impact on this analysis is the increase in minimum RCS flow, which has a small impact on the results.

General Description of the Event

An RCS overcooling event caused by a malfunction within the feedwater system can be initiated by a sudden increase in feedwater flow rate, a sudden decrease in the feedwater enthalpy, or inadvertent startup of the EFW System. Failures or malfunctions of the Feedwater Control System can initiate an increase in feedwater flow rate or excess feedwater. A sudden reduction in feedwater enthalpy can be initiated by loss of the high pressure feedwater heaters. In order to lose this heating, four valves (one per extraction line) would need to be closed.

Inadvertent startup of the EFW system would supply less than 840 gpm (per pump assuming a steam generator pressure of 900 psig) of relatively cold water from the condensate storage tank to the steam generators. Inadvertent startup of the EFW pumps results in significantly less feedwater than the increase in main feedwater flow rate postulated below due to a malfunction of the control valves and overspeed of the main feedwater pumps. The inadvertent actuation of EFW system event is therefore bounded.

A feedwater system malfunction can cause a reduction in RCS temperature followed by an increase in reactor power in the presence of a negative Moderator Temperature Coefficient (MTC). The increase in feedwater flow transient is terminated by either the CPC VOPT or a CPC low DNBR trip.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the CPCs provide sufficient protection such that the minimum DNBR and maximum peak LHR are within SAFDLs.

The criteria for the RCS Overcooling event are the following:

DNBR ≥ DNB SAFDL
Peak LHR ≤21 KW/ft

The Excess Heat Removal due to Feedwater System Malfunction event is described in Chapter 15.1.10 of the SAR (Reference 1-1).

Impact of Changes

The RSGs result in a larger steam generator heat transfer area and in higher steam generator pressures. These result in a faster cooldown (primary to secondary heat transfer) during the post-trip event. Maximizing the immediate post-trip cooldown results in a closer approach to the SAFDLs.

The maximum possible feedwater flow is fixed by feedwater system design, but the steady-state feedwater flow at 3026 MWt is greater than the steady-state flow at the current power level. Therefore, the maximum possible increase in feedwater flow is greater for an excess feedwater flow event initiated at the current power level rather than at 3026 MWt. This analysis conservatively assumes the same relative increase in feedwater flow that is available at the current rating is also available at the increased power rating.

The increase in the most negative MTC (more negative) results in a faster transient power rise. More rapid cooldown results in a larger addition of positive reactivity, which results in a faster increase in core power and heat flux. The faster transient power response presents a greater challenge to the CPCs response and a larger overshoot of core power and heat flux at the time of trip. This larger overshoot results in a more rapid approach to the SAFDLs after reactor trip.

Credit for the CPC VOPT results in a plant trip prior to the high linear power trip, resulting in event termination.

Analysis Overview

The methodology used in this analysis is similar to the methodology used in the current analysis of record, except that the CENTS code is used instead of the CESEC code. The CENTS code has been previously approved for ANO-2. The minimum DNBR evaluation was determined using the CETOP code.

Two different types of feedwater malfunction events were reviewed:

1. An instantaneous increase in main feedwater to 160% of initial flow to both steam generators with a decrease in feedwater enthalpy of 152 Btu/lbm.
2. A loss of two feedwater heaters in both main feedwater trains that resulted in a decrease in feedwater enthalpy of 86 Btu/lbm.

Of the two feedwater malfunction events, the instantaneous increase in main feedwater to 160% of initial main feedwater flow with a decrease in feedwater enthalpy of 152 Btu/lbm was determined to be the most adverse event of the two.

Input parameters from Table 1.5.1-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The BOC Doppler curve in Figure 1.0.2-2 was assumed.
2. A delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 was assumed.
3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. A CEA worth of -5.0% $\Delta\rho$ was assumed.
4. The CPC VOPT was employed in the analysis. A cold leg RTD response time of 8 seconds was accounted for along with a CPC trip delay time of 0.60 seconds.
5. An initial core power of 3087 MWt, based on a rated power of 3026 MWt and a 2% uncertainty, was assumed.
6. The most negative MTC of -3.8×10^{-4} $\Delta\rho/°F$ was assumed..
7. Initial RCS pressure was assumed to be 2300 psia.
8. Initial RCS flow was assumed at the minimum value of 315,560 gpm.

9. For the feedwater flow increase event, it was assumed that the main feedwater flow to both steam generators increased from 102% to 160% of the flow at 3026 MWt instantaneously (0.5 seconds) with a decrease in feedwater enthalpy of 152 Btu/lbm.

10. Installation of the RSGs was assumed.

11. An initial steam generator pressure of 1003 psia was assumed.

Analysis Results

An increase in main feedwater can cause an overcooling of the RCS as a result of the decreasing cold leg inlet temperature. Core power also increases due to the reactivity feedback interaction caused by the lower cold leg inlet temperature. The CPC VOPT terminates the transient.

The NSSS and RPS responses for excess heat removal due to feedwater system malfunction are shown in Table 1.5.1-2 and in Figures 1.5.1-1 through 1.5.1-5.

For the limiting feedwater malfunction event, the increase in feedwater flow to 160% with a 152 Btu/lbm decrease in feedwater enthalpy, the minimum DNBR is greater than 1.25 and the peak linear heat rate is less than 21 KW/ft. Thus, the SAFDLs are protected.

This event was reanalyzed due to various changes in RSG and plant parameters. The results have been determined to be acceptable. The proposed TS changes do not impact this analysis except due to the small increase in minimum RCS flow which has a minimal impact on the results.

1.5.2 Excess Heat Removal due to Main Steam System Valve Malfunction

Summary

The objective of Excess Heat Removal due to Main Steam System Valve Malfunction event analysis is to document the impact of:

1. the RSGs,
2. a lower SIAS setpoint,
3. an increase in the MSIS setpoint,
4. credit the CPC VOPT,
5. an increase in rated power to 3026 MWt,
6. the increase in the most negative MTC (more negative),
7. an increase in the turbine admission valve capacity, and
8. offsite releases.

The impact of the above changes results in no violation of the SAFDLs and is valid for both Cycle 15 and the increase in rated power to 3026 MWt.

The only proposed TS changes that have an impact on this analysis are the increase in minimum RCS flow, the change in the MSIS setpoint, and the change in the SIAS setpoint. A change in the offsite release is expected for this event due to the increase in RSG secondary inventory. Radiological doses from the MSLB and FWLB are considered bounding.

General Description of the Event

Reactor Cooling System (RCS) overcooling events can result from the malfunction of valve(s) within the Main Steam System.

The excess heat removal due to malfunction of the Main Steam System valves (referred to as excess load event) may be caused by:

(a) Rapid opening of the turbine admission valves,

(b) Opening of one of the SDBCS valves, and

(c) Inadvertent opening of an atmospheric dump valve (ADV).

Similar to the increase in feedwater flow event, the CPC will terminate this transient on either a VOPT or low DNBR trip to protect the SAFDLs.

Of the three types of valve malfunctions listed above that can initiate excess steam flow, inadvertent opening of an ADV is the most adverse. The increase in steam flow caused by rapid opening of the turbine admission valves from their steady state 100% power position to full open position is typically less than the design flow capacity of a fully open atmospheric dump valve. The high pressure turbine will be modified for Cycle 15 to accommodate the RSG pressures and anticipated power uprate efforts. The excess capacity of the turbine admission valves will be less than that of the ADV event analyzed below, assuming the plant is operating at normal 100% power conditions with a steam generator pressure of approximately 940 psia. The turbine admission valve capacity under high steam generator pressure conditions, (1000 psia) will slightly exceed the ADV capacity by approximately 2%. This excess capacity is only available in an off normal operating regime (plant operation at the high end of the TS Tcold operating range). This analysis assumes the inadvertent opening of one ADV upstream of the MSIV associated with steam generator A. At the full open position, this analysis conservatively assumed 13% flow capacity for the dump valve at power uprate conditions.

Additionally, the excess load event is analyzed from different initial power levels, MTC values, and load demands as part of the CPC filter verification analysis (see Section 1.5.8). The object of this is to verify that the CPC Tcmax and Tcmin algorithms provide conservative input into the CPC VOPT and CPC Low DNBR calculations. If the CPC filter coefficients/algorithms are non-conservative, then a penalty factor is provided for inclusion in the CPC constants calculation. The fastest events present the most challenge to the CPCs, since input is changing rapidly. If the CPC provides adequate protection for the faster events, then the slower events are also protected.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the CPCs provide sufficient protection such that the minimum DNBR and maximum peak LHR are within the SAFDLs.

The criteria for the RCS Overcooling event are the following:

DNBR ≥ DNB SAFDL
Peak LHR ≤21 KW/ft
Radiological Doses ≤small fraction (10%) of 10CFR100 limits

The Excess Heat Removal due to Main Steam System Valve Malfunction event is described in Chapter 15.1.10 of the SAR (Reference 3.6-1).

Impact of Changes

The RSGs result in higher steam generator heat transfer areas and pressures. Higher steam generator heat transfer area and pressure result in a faster cooldown (primary to secondary heat transfer) during the post-trip event. Maximizing the immediate post-trip cooldown produces a closer approach to the SAFDLs.

The increase in rated power would minimize the cooldown difference between the rated SDBCS valve flow rate and initial power. This analysis conservatively assumed that the ADV flow rate is 13% of the total steam flow for 3026 MWt.

The increase in the most negative MTC (more negative) results in a faster transient cooldown. More rapid cooldown results in a larger addition of positive reactivity, which results in a faster increase in core power and heat flux. The faster transient power response presents a greater challenge to the CPC response and a larger overshoot of core power and heat flux at the time of trip. This larger overshoot results in a more rapid approach to the SAFDLs after reactor trip.

An increase in turbine valve capacity results in a slightly faster and larger cooldown event. As indicated above, during normal 100% power operation at 2815 MWt, the turbine valve excess capacity is bounded by the 13% flow capacity assumed for an ADV. A mismatch between primary and secondary power slightly larger than the capacity of one ADV, is applicable to off-normal Cycle 15 operating regimes. The mismatch is slightly larger than the capacity of one ADV. Even though operation with this excess capacity is not anticipated for Cycle 15, this difference is covered by the CPC dynamic filters analysis in Section 1. 8. For a rated power of 3026 MWt, the opening of the ADV will bound the turbine valve excess capacity.

This analysis credits the CPC VOPT, which will limit the potential power rise and terminate the event.

The increase in the MSIS setpoint will improve the offsite releases for this event. However, power uprate assumptions, larger steam generator inventories, and a change in analysis methodology result in a small increase in offsite releases. Due to the bounding nature of the MSLB and FWLB results, no explicit dose calculation has been performed.

Analysis Overview

The methodology used in this analysis is similar to the methodology used in the current analysis, except that the CENTS code is used instead of the CESEC code. The CENTS code has been previously approved for ANO-2. The minimum DNBR evaluation was determined using the CETOP code.

Input parameters from Table 1.5.2-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The BOC Doppler curve in Figure 1.0.2-2 was assumed.

2. A delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 of this enclosure was assumed.

3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. A CEA worth of -5.0% $\Delta\rho$ was assumed.

4. The analysis is conservatively based on an inadvertent opening of an ADV with a flow capacity of approximately 13% full power flow. By maintaining this conservative assumption, the impact of increasing the rated power was very small.

5. The CPC VOPT was employed in the analysis. A cold leg RTD response time of 8 seconds was included along with a CPC trip delay time of 0.60 seconds.

6. An initial core power of 3087 MWt, based on a rated power of 3026 MWt and a 2% uncertainty, was assumed.

7. The most negative MTC of -3.8×10^{-4} $\Delta\rho/°F$ was assumed. This results in the largest radial power distortion in the core due to the core temperature asymmetry.

8. The analytical MSIS setpoint was 693 psia. The MSIVs, MFIVs, and back-up MFIVs all receive an MSIS signal to close. An analytical response time of 4.9 seconds (which includes a 1.4 second MSIS response time) was assumed for the MSIVs. The MFIVs were assumed to close in 26.4 seconds (including the 1.4 second MSIS response time), which is longer than the time to close the back-up MFIVs.

9. Installation of the RSGs was assumed.

10. An initial RCS pressure of 2300 psia was assumed.

11. An initial RCS flow of 315,560 gpm was assumed.

12. An initial steam generator pressure of 1003 psia was assumed.

13. An analytical SIAS setpoint of 1400 psia was assumed. A response time of 40 seconds for the HPSI pumps to reach full speed was also assumed.

14. The MSSVs are assumed to lift early at -3.5%.

Analysis Results

The impact of the ADV malfunction is an overcooling of the RCS. Core power also increases due to the reactivity feedback interaction caused by the lower cold leg inlet temperature. The CPC VOPT terminates the transient.

The NSSS and RPS responses for excess heat removal due to opening of an ADV are shown in Table 1.5.2-2 and in Figures 1.5.2-1 through 1.5.2-5.

For the opening of an atmospheric dump valve event, the minimum DNBR is greater than 1.25 and the peak LHR is less than 21 KW/ft. Thus, the SAFDLs are protected.

A small increase in radiological dose is expected due to the larger RSG secondary inventory. No dose calculation was performed for this event, because as indicated in Section 1.0.5, doses for this and other AOOs are deemed to be acceptable due to the bounding nature of the MSLB and FWLB doses.

The proposed TS changes with respect to minimum RCS flow, the MSIS setpoint, and the SIAS setpoint have been considered in this analysis.

1.5.3 Major Secondary System Pipe Breaks with or without Concurrent Loss of AC Power

Summary

The objective of the MSLB with or without a concurrent loss of AC power event analysis is to document the impact of:

1. the RSGs,
2. an increase in rated power to 3026 MWt,
3. the increase in the most negative MTC (more negative),
4. an increase in the Low Steam Generator Pressure Trip and MSIS setpoints,
5. a reduction in CEA worth at trip,
6. crediting the SITs,
7. crediting the High Containment Pressure Trip and CPC VOPT,
8. an increase in the MSIV, MFIV, and Backup MFIV response times,
9. a decrease in the CPC Low RCP Shaft Speed trip analytical setpoint,
10. a larger RCS and secondary inventory, and
11. a change in radiological dose methodology.

The impact of the above changes results in no violation of SAFDLs for the post-trip event and the radiological doses remain less than the 10CFR100 limits. This analysis is valid for both Cycle 15 and the increase in rated power to 3026 MWt. Due to changes in the methods presented in Section 1.0.5 and the larger RCS and secondary inventory, higher whole body doses than those currently in the SAR have been calculated, resulting in a USQ.

This analysis is related to the proposed TS changes for minimum RCS flow, Low Steam Generator Pressure setpoints, and Low Pressurizer Pressure setpoints.

General Description of the Event

A MSLB is defined as a pipe break in the main steam system. The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator, resulting in a decrease in the overall RCS temperature and pressure.

In the presence of a negative MTC, the cooldown causes positive reactivity to be added to the core. A highly negative MTC in conjunction with a major secondary system pipe break can combine to degrade SDM and result in a potential post trip return to power.

With a concurrent loss of AC power (LOAC), power is lost to the CEA holding coils which results in an immediate reactor trip. For conservatism, the analysis assumes that the reactor will trip on the CPC trip of Low Primary Coolant Pump Shaft Speed, approximately one second after the pipe break. With offsite power available, the reactor trips on High Containment Pressure, Low Steam Generator Pressure, Low Steam Generator Level, or High Core Power.

For major secondary system pipe breaks, the Low Steam Generator Pressure Trip initiates a MSIS which causes closure of the MSIVs and MFIVs. The steam flow from the intact steam generator is terminated by the complete closure of the MSIVs. Since the pipe break is assumed to occur upstream of the MSIV, the steam flow from the affected steam generator is not terminated until the affected steam generator dries out. The large cooldown of the RCS results in the reduction of the RCS pressure, which will empty the pressurizer and initiate a SIAS. The emptying of the affected steam generator and the initiation of boron injection terminates the return to power and causes the core reactivity to decrease. The operator, via the appropriate emergency procedures, may initiate plant cooldown by manual control of ADVs, or by opening the MSIV bypass valve associated with the intact steam generator, anytime after reactor trip occurs. The plant is then cooled to the shutdown cooling temperature, at which time shutdown cooling can be initiated.

In the current analysis, four MSLB events were chosen to maximize the potential for a post-trip return-to-power. The events were:

1. A nozzle break MSLB at HFP concurrent with a LOAC,
2. A nozzle break MSLB at HFP with offsite power available,
3. A nozzle break MSLB at HZP concurrent with a LOAC, and
4. A nozzle break MSLB at HZP with offsite power available.

In addition to the above combinations, the HFP and HZP cases with offsite power available are analyzed for both Inside Containment (IC) and Outside Containment (OC) breaks. For the MSLB cases with loss of offsite power, the IC cases are bounding (more adverse) than the OC cases with respect to the post-trip return-to-power. This is due to reactor trip being related to the loss of offsite power and the MSIS actuation being based on a lower setpoint value IC. This analysis looked at the following MSLB events:

1. A nozzle break at HFP with concurrent LOAC.
2. A nozzle break IC at HFP with offsite power available.

3. A guillotine break OC at HFP with offsite power available.

4. A nozzle break at HZP with concurrent LOAC.

5. A nozzle break IC at HZP with offsite power available.

6. A guillotine break OC at HZP with offsite power available.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the radiological doses are within their respective limits and that a coolable geometry is maintained.

The criteria for the MSLB with and without LOAC events are as follows:

Maintain a coolable geometry
Radiological Doses are within 10CFR100 limits

The Main Steam Line Break (MSLB) with or without a concurrent loss of AC power event is described in Chapter 15.1.14.1 of the SAR (Reference 1-1).

Impact of Changes

The RSGs result in higher steam generator heat transfer area, inventory, and pressure. Higher steam generator heat transfer area and pressures result in a faster cooldown (primary to secondary heat transfer) during the post-trip event. Maximizing the immediate post-trip cooldown produces a closer approach to the SAFDLs. The larger steam generator inventory also allows for a larger potential cooldown.

The increase in rated power maximizes the amount of energy that is removed by the broken steam line and the cooldown effect on the RCS temperature.

The increase in the most negative MTC (more negative) results in a more adverse reactivity addition during the post-trip transient cooldown. The larger post-trip reactivity addition challenges the post-trip negative reactivity from the CEA worth at trip and the boron added from the safety injection system. Should the positive reactivity from the MTC and Doppler temperature changes be greater than the post-trip combined negative reactivity, the potential exists for the core to go critical.

The faster cooldown rate due the RSGs heat transfer area, larger inventory, higher pressures, an increase in rated power, and a more negative MTC are compensated by the steam generator internal flow restrictors. These restrict the maximum effective break area to less than 2 ft^2, approximately one-third that of the previous break size area of 6.36 ft^2.

The Low Steam Generator Pressure Trip and MSIS setpoints were increased due to higher operating steam generator pressures.

The reduction in CEA worth at trip results in less negative reactivity to offset the positive reactivity from MTC and Doppler temperature changes.

The SITs were credited in the analysis to help offset the positive reactivity from MTC and Doppler temperature changes.

Since the RSGs internal flow restrictors result in a slower depressurization of the steam generator, the actuation of the Low Steam Generator Pressure Trip is delayed. Other RPS trips such as the High Containment Pressure Trip and CPC VOPT can occur prior to the Low Steam Generator Pressure Trip.

The increase in response times for the MSIVs results in a slightly faster cooldown early in the event due to the longer time to isolate the intact steam generator. The overall effect is more than offset by the new RSG internal flow restrictor.

The increase in response times for the FWIVs and Backup FWIVs result in a longer cooldown of the affected steam generator since more inventory is added due to the longer isolation time of the main feedwater.

The CPC Low RCP Shaft Speed trip analytical setpoint was decreased. This impacts only the concurrent LOAC power cases and its impact is negligible.

The change in radiological dose methodology along with the increase in steam generator inventory, results in an increase in the EAB and LPZ whole body dose.

Analysis Overview

The methodology used in this analysis is the same as that used in the current analysis.

This analysis has utilized the CENTS computer code for the transient analysis simulation. The minimum DNBR evaluation was determined using the HRISE code which employed the MacBeth correlation.

The no moisture carryover steam line break events were reanalyzed. CENTS was used to model the NSSS response, RCP coastdown, and natural circulation. RELAP5/MOD3.1 was used to model the feedwater system response for the HFP (or full load) cases. HRISE was used to calculate the thermal margin on DNBR. ROCS/HERMITE were used to assess reactivity feedback and peaking.

Input parameters for HFP and HZP from Table 1.5.3-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. A double-ended guillotine break (6.357 ft^2) causes the greatest cooldown of the RCS and the most severe degradation of SDM. Due to integral flow restrictors, this results in an equivalent break area of less than 2.0 ft^2.

2. A break inside or outside the containment building, upstream of the MSIVs and flow measuring venturis causes a non-isolatable condition in the affected steam generator.

3. A SIAS is actuated when the pressurizer pressure drops below 1400 psia. Time delays associated with the safety injection pump acceleration and valve opening are taken into account. A 40-second HPSI response time was assumed to account for these delays. Additionally, the event was initiated from the highest pressure allowed by the TSs to delay the effect of the safety injection boron.

4. The cooldown of the RCS is terminated when the affected steam generator blows dry. As the coolant temperatures begin increasing, positive reactivity insertion from moderator reactivity feedback decreases. The decrease in moderator reactivity combined with the negative reactivity inserted via boron injection cause the total reactivity to become more negative.

5. CENTS is used to model the RCP coast down on a loss of offsite power. The CPC low DNBR (based on pump speed) trip is credited in this analysis following a loss of offsite power. The analysis assumed a CPC low DNBR trip setpoint based on 95% of RCP speed with a 1.0 second response time.

6. Due to the reduction of the effective break area, a combination of RPS trips was employed to generate a reactor trip for the offsite power available cases.

   A Low Steam Generator Pressure Trip setpoint of 693 psia for outside containment breaks (normal environment) was assumed with a 1.3 second response time.

   A High Containment Pressure Trip setpoint of 20.7 psia for inside containment breaks (harsh environment) was assumed with a 1.59 second response time.

For HFP outside containment breaks (normal environment), the CPCs is also available to generate a reactor trip. A CPCs Variable Overpower Trip (VOPT) was assumed with a conservative 1.2 second response time.

7. MSIS is actuated on a low steam generator pressure setpoint of 658 psia for inside containment breaks (harsh environment) and 693 psia for outside containment breaks (normal environment). The MSIVs, MFIVs and back-up MFIVs all receive an MSIS signal to close. A response time of 4.9 seconds (which includes a 1.4-second MSIS response time) was assumed for the MSIVs. The MFIVs and Back-up MFIVs were assumed to close in 41.4 seconds and 34.9 seconds with a loss of offsite power, and 26.4 seconds and 19.9 seconds with offsite power available, respectively.

8. The HERMITE code (Reference 1-4) was used to calculate the reactivity for the post-trip return to power portion of the analysis. This was done since the HERMITE code, which is a three-dimensional, coupled neutronics, open channel thermal hydraulics code, can more accurately model the effects of moderator temperature feedback on the power distribution and reactivity for the critical configuration existing during the return to power. The HERMITE results used in the ANO-2 analysis were actually obtained from a parametric study performed for Calvert Cliffs Unit 1 Cycle 7. ANO-2 specific ROCS calculations were used to confirm the applicability of these parametric results to ANO-2.

9. Three-dimensional power distribution peaks (Fq) were determined with the ROCS and HERMITE evaluations mentioned above. Axial profiles consistent with these conservative power distribution peaks were utilized in the analysis.

10. The power produced by the decay of the initial condition delayed neutron precursors and by nominal decay power is distributed according to the nominal power distribution.

11. The thermal margin on DNBR in the reactor core was simulated using the HRISE computer program, which employed the MacBeth CHF correlation and a 1.3 DNBR limit described in Reference 1-14. RCS conditions from CENTS (RCS temperature, pressure, flow, and power) are used in the HRISE thermal margin calculations.

12. The EOC Doppler curve in Figure 1.0.2-2 was assumed. This was based on the most negative FTC. This FTC, in conjunction with the decreasing fuel temperatures, causes the greatest positive reactivity insertion during the steam line break event.

13. The delayed neutron fraction assumed is the maximum value including uncertainties for end-of-cycle conditions (total delayed neutron fraction, β, 0.005994). This too minimizes neutron generation time and thus increases the potential for return to power.

14. EFW is conservatively modeled to actuate early.

15. The SITs were credited in this analysis only for the AC power available cases. The SITs were configured to have the minimum allowed pressure with the maximum volume of water and minimum water temperature. The boron concentration was at the minimum allowed value.

16. A minimum initial RCS flow of 315,560 gpm was assumed for HFP, and a minimum initial RCS flow of 314,682 gpm was assumed for HZP.

17. An initial steam generator pressure of 1001 psia was assumed for HFP, and an initial steam generator pressure of 1065 psia was assumed for HZP.

The conservative assumptions included in the HZP and HFP simulations are discussed below.

The MTC assumed in the analysis corresponds to the most negative value. This negative MTC results in the greatest positive reactivity addition during the RCS cooldown caused by the steam line break. Since the coefficient of reactivity associated with moderator feedback varies significantly over the range of moderator density covered in the analysis, a curve of reactivity insertion versus moderator density rather than a single value of MTC is assumed in the analysis. The moderator cooldown curve used in the analysis (Figure 1.5.3-1) was conservatively calculated assuming that on reactor trip, the highest worth control element assembly is stuck in the fully withdrawn position. The effect of uneven temperature distribution on the moderator reactivity is accounted for by assuming that the moderator reactivity is a function of the lowest cold leg temperature.

For conservatism, the full steam generator heat transfer surface area is assumed to always be covered by the 2-phase level until a steam generator becomes essentially empty.

The minimum CEA worth assumed to be available for shutdown at the time of reactor trip at the maximum allowed power level is -6.84 % $\Delta\rho$. For the HZP cases a shutdown CEA worth of -4.84 %$\Delta\rho$ was used. The scram worths used are consistent with the moderator cooldown curve and stuck rod assumed in the analysis. The CEA reactivity addition curve of Figure 1.0.2-3 adjusted to a worth of -6.84 %$\Delta\rho$ was used in the HFP cases. The HZP cases assumed a CEA drop time consistent with Figure 1.0.2-4 with the 0.6 second holding coil delay time and a scram worth of -4.84 %$\Delta\rho$; however, a more conservative normalized reactivity insertion versus CEA position for a +0.6 ASI curve was used.

The EFW system is conservatively modeled to initiate early with both EFW pumps available, maximizing the potential cooling that could occur. System response times, flows and setpoints are assumed based on increasing the cooling potential of the EFW system.

These analyses have considered the worst single failure of an active component. The analysis assumed that, for the loss of AC power cases, one EDG failed to start. The failure of an EDG resulted in the failure of one HPSI pump and one of the MFIVs to close. The faster closing back-up MFIVs were assumed to remain open. For the HFP case with AC available, a bus fast transfer failure is the most limiting single failure. This failure was modeled as the failure of the back-up MFIV and a HPSI pump. A fast transfer failure would only result in the delayed actuation of the back-up MFIV and HPSI pump. These components would be actuated once the EDG has started. Therefore, the modeling of the fast transfer failure was conservative. This conservative modeling of a fast transfer failure was slightly more limiting than the single failure of a main feedwater pump to trip, which is consistent with the current analysis. A single failure of a HPSI pump to start was assumed for the HZP case with AC available.

The HFP feedwater addition to the steam generators assumed in this analysis was re-generated due to the installation of the RSGs and increase in rated power. The analysis used a RELAP5/MOD3.1 model (Reference 1-13) to generate the feedwater system response. The steam generator pressure profiles and time of MSIS were verified to be consistent between the CENTS and RELAP5/MOD3.1 results. For the HZP (or no load) cases, feedwater flow is modeled by matching the energy input by the core at the start of the event. An increase in feedwater flow is assumed based on the capacity of the auxiliary feedwater (AFW) pumps.

The key parameters used for the post-trip steam line break analyses are listed in Table 1.5.3-1. For the HFP cases, an RCS flow of 315,560 gpm was assumed. For the HZP cases a lower RCS flow of 314,682 gpm was assumed.

The analysis input and assumptions used in the calculation of the radiological dose releases for the HFP and HZP MSLB events are discussed in Section 1.0.5 of this enclosure and have been incorporated in this analysis with the following clarifications:

1. A MSLB location OC but upstream of the MSIVs was assumed.

2. The condenser is assumed unavailable for cooldown due to the loss of offsite power. Thus, the entire cooldown was performed by dumping steam to the atmosphere from the steam generators.

3. The affected steam generator was assumed to boil dry and is a direct source to the atmosphere for all isotopes carried by the tube leakage. The analysis conservatively assumed a decontamination factor of 1.0 for the affected steam generator.

Analysis Results

Tables 1.5.3-2 through 1.5.3-5 present the sequence of events for the HFP and HZP steam line break cases with and without a concurrent loss of AC power. Only the limiting inside or outside containment case was presented for the HFP and HZP conditions with AC available. Figures 1.5.3-2 through 1.5.3-25 show the transient response for key parameters.

The HFP results of this analysis indicate that a slight return to criticality occurs for the case with loss of AC power. The new maximum post trip reactivity values are 0.0173 %Δρ and -0.0218 %Δρ considering a loss of AC and offsite power available, respectively. The peak return to power and minimum DNBR values are 2.76% and 1.70, and 4.26% and 2.72 considering a loss of AC and offsite power available, respectively.

The HERMITE 3-D feedback and 3-D peaking factors are power dependent. The Cycle 15 - 2815 MWt values were more limiting than the Cycle 16 - 3026 MWt values. This input in conjunction with the RSG resulted in a slightly more adverse post-trip return to criticality for the HFP with loss of offsite power event (see the sequence of events in Table 1.5.3-2, maximum post trip reactivity is 0.0211 %Δρ, peak return to power is 3.39% of 2815 MWt, and minimum DNBR is 1.56). The times for the sequence of events were within two seconds of the Cycle 16 sequence of events. Since the results for Cycle 15 are valid for only one cycle, they are provided as footnotes to the Cycle 16 sequence of events.

The HZP results of this analysis indicate that a slight return to critical occurs for the case with loss of AC power. The new maximum post trip reactivity values are +0.206 %Δρ and -0.545 %Δρ considering a loss of AC and offsite power available, respectively. The peak return-to-power and minimum DNBR values are 0.15% and >10, and zero and >10 considering a loss of AC and offsite power available, respectively.

As these results indicate acceptable DNBR values, no fuel failure is predicted. The results of the steam line break analyses demonstrated that there were no calculated fuel failures, thus the coolable geometry has been maintained.

A sensitivity study was completed on CEA worth at trip to determine the lowest CEA worth value that would produce either a DNBR of 1.30 (MacBeth) or a peak Linear Heat Rate of 21 KW/ft. The method used was to hold all input parameters, both physics input and plant values constant, and lower the CEA worth at trip until one of the above limits was reached.

The purpose of this sensitivity study was to determine the amount of CEA worth at trip that could be utilized in future reload efforts to offset other physics parameters. Thus, the incremental CEA worth at trip of 0.09 %$\Delta\rho$ can be credited in future reload efforts.

The radiological doses for the EAB and LPZ for an event generated iodine spike and no iodine spike are less than a small fraction of the 10CFR100 limits of 30 Rem for the thyroid and 2.5 Rem for whole body. For a pre-existing iodine spike, the EAB and LPZ doses remain within the 10CFR100 limits of 300 Rem for thyroid and 25 Rem for whole body. The calculated results for all doses are presented in Tables 1.5.3-6 and 1.5.3-7 of this enclosure.

1.6 Steam Generator Tube Rupture with or without a Concurrent Loss of AC Power

Summary

The objective of the Steam Generator Tube Rupture with and without a LOAC event evaluations is to determine the impact of the RSGs for Cycle 15.

There is no impact due to the proposed TS changes and the RSGs. This event is the limiting event with respect to the low pressurizer pressure SIAS setpoint.

General Description of the Event

The Steam Generator Tube Rupture (SGTR) event with or without a LOAC power is a penetration of the barrier between the RCS and the main steam system. Integrity of this barrier is significant from a radiological standpoint. A leaking steam generator tube would allow transport of reactor coolant into the main steam system. Radioactivity contained in the reactor coolant would mix with the shell side water in the affected steam generator. A direct release path to atmosphere could result in a challenge to the 10CFR100 radiological dose limits.

The initiating event is the double-ended rupture of one U-tube with either a LOAC or no loss of AC power. For the concurrent LOAC power event, a CPC Low RCP Shaft Speed Trip occurs when any one of the four RCP shaft speeds drops below 95% of its nominal speed. For the no LOAC power event, the CPC Low DNBR Trip will provide a reactor trip and prevent the DNB safety limit from being exceeded.

The double-ended tube rupture with concurrent LOAC power results in a slow RCS depressurization event after the initial RCS pressure increases due to the simultaneous loss of AC power. As a result of the LOAC, electrical power would not be available for station auxiliaries such as the RCPs, the steam generator feedwater pumps, and the main circulating water pumps. The plant would experience a simultaneous loss of load, loss of feedwater flow, and loss of forced reactor coolant flow. For the first five seconds this event behaves like a loss of normal AC power.

Due to the concurrent loss of AC power, the SDBCS valves are unavailable and the secondary steam release would occur via the MSSVs prior to operator action. Operator action is taken at 30 minutes. At this time, the operator isolates the affected steam generator and initiates a controlled cooldown to shutdown cooling using the ADV of the intact steam generator. After the RCS temperature reaches the shutdown cooling temperature, the operator engages the shutdown cooling system. RCS heat removal via the steam generators is terminated at this time.

For the transient with AC power available, station auxiliaries would be available after trip to mitigate the results of the event. The SDBCS valves are available and most of the secondary steam release would occur directly to the condenser. Operator action is taken at 30 minutes. At this time, the operator isolates the affected steam generator and initiates a controlled cooldown to shutdown cooling using either the SDBCS valves or the ADV of the intact steam generator. After the RCS temperature reaches the shutdown cooling temperature, the operator engages the shutdown cooling system. RCS heat removal via the steam generators is terminated at this time.

The initial RCS pressure spike is small and there is no challenge to the PSVs. The actuation of MSSVs will prevent the secondary system pressure from exceeding 110% of its design limit.

The SGTR with concurrent LOAC event is analyzed to determine the radiological doses for the EAB and the LPZ doses. Since the steam releases for this event are directly to the atmosphere via the MSSVs and the intact steam generator ADV, the SGTR event radiological doses with AC power is bounded.

Purpose of Analysis and Acceptance Criteria

The purpose of this evaluation is to determine that the SGTR event EAB and LPZ radiological dose results are less than 10CFR100 limits.

The criteria for the SGTR event with and without concurrent LOAC are the following:

DNBR ≥ DNB SAFDL
Peak RCS Pressure ≤2750 psia
Peak Secondary System Pressure ≤1210 psia
Radiological Doses less than 10CFR100 limits

The SGTR event with and without concurrent LOAC is described in Chapter 15.1.18 of the SAR (Reference 1-1).

Impact of Changes

The RSGs result in a larger steam generator volume and liquid mass, a higher steam generator pressure, a smaller steam generator primary side flow resistance, and a larger number of U-tubes that have a longer length and a smaller diameter.

The larger steam generator volume results in greater steam generator liquid and steam inventories, which impact radiological dose results slightly. Higher steam generator pressures result in a lower pressure difference between primary and secondary systems, which results in a slower primary mass leak rate into the affected steam generator. Although the overall primary side flow resistance is lower due to the increase in the number of U-tubes, the flow resistance for an individual U-tube is higher due to the longer length and smaller diameter. This also results in a smaller leak rate into the affected steam generator. A smaller leak rate results in lower total primary mass release to the affected steam generator, which results in lower steam generator activity and lower radiological doses.

An increase in the minimum RCS flow results in a small benefit in the calculation of required thermal margin and minimum DNBR for this event.

Analysis Overview

The method used is a comparison of changes in key input parameters between those documented in Reference 1-1 versus the new data due to the RSGs.

The major change is the actual steam generator. The RSG consists of the following:

1. A larger secondary side volume of 8172 ft^3 versus 7957 ft^3
2. A larger number of U-tubes per steam generator of 10,637 versus 8411
3. A smaller U-tube inside diameter of 0.608 inches versus 0.654 inches
4. Different U-tube loss coefficients (longer active and inactive U-tube lengths)
5. Higher steam generator operating pressure

Analysis Results

An engineering evaluation of changes in key input data was employed to assess the impact on the SGTR events. No computer codes were used. The comparison of key input parameters demonstrated that all values were either the same or conservative for Cycle 15, except for some RSG data. The major driving force is the leak rate from the broken U-tube. The leak rate for the RSG would be lower than for the current steam generator due to the following:

1. The smaller U-tube diameter results in a smaller flow that is directly proportional to the square of the diameter. This alone results in reduction in U-tube leak rates of 13%.

2. The higher secondary side pressure results in a lower pre-trip delta-pressure from primary to secondary system.

3. A comparison of the U-tube flow resistances resulted in a reduction of the U-tube leak rate of at least 5% due to a larger U-tube flow resistance.

Since the U-tube leak rate is less, the primary mass released to the affected steam generator would be less than that documented, hence no increase in radiological doses. The proposed TS changes do not negatively impact this analysis. Due to the bounding nature of the current analysis, this event was not reanalyzed. The existing analysis credits a SIAS setpoint of 1600 psia. From this limiting assumption, the new TS setpoint has been determined using instrument uncertainties under normal conditions.

1.7 Instantaneous Closure of a Single MSIV

Summary

The objective of the Instantaneous Closure of a Single Main Steam Isolation Valve event analysis is to document the impact of:

1. the RSGs,
2. an increase in rated power to 3026 MWt,
3. the increase in the most negative MTC (more negative), and
4. an increase in RCS flow.

The impact of the above changes results in no violation of the SAFDLs and is valid for both Cycle 15 and the increase in rated power to 3026 MWt.

The only proposed TS changes which have an impact on this analysis is the increase in minimum RCS flow, which has a small beneficial impact.

General Description of the Event

An Asymmetric Steam Generator Transient (ASGT) is an event that causes a rapid imbalance in steam flow between the two steam generators. This event is initiated by an instantaneous closure of one of the two MSIVs. The instantaneous MSIV closure causes the temperature and pressure in the affected steam generator to increase. The unaffected steam generator then picks up the lost load and in doing so causes its temperature and pressure to decrease.

This event also causes an asymmetry in the reactor core inlet temperatures. A skewed power distribution in the reactor core will also occur due to the influence of the MTC. This in turn may cause an increase in core power peaking and the minimum DNBR to be approached before the power decreases. This event is terminated by a CPCs ASGT Trip (high differential temperature between the cold legs).

The ASGT event is analyzed to determine the minimum initial thermal margin that must be maintained by the TS LCOs such that, in conjunction with the RPS, the DNB SAFDL is not violated during the event. This initial margin is monitored by the COLSS, when in service, and by the operators using the CPC when COLSS is out of service (CPC data compared to DNBR limit plot).

The principal process variables that determine thermal margin to DNB in the core are monitored by the COLSS. The COLSS computes a power operating limit, which ensures that the thermal margin available in the core is equal to or greater than that needed to maintain the minimum DNBR greater than the DNBR limit.

The action of the RPS and the insertion of the CEAs mitigate the decrease in DNB thermal margin due to the asymmetry in core inlet temperature and core power distribution. This results in the minimum DNBR occurring in less than ten seconds after the initiation of the event.

Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to calculate the ASGT event DNB thermal margin requirements that must be reserved in the TS LCOs. This assures that the minimum DNBR and the peak LHR for the event do not exceed the DNB and centerline-to-melt SAFDLs.

The criteria for the ASGT event are the following:

DNBR $\geq$ DNB SAFDL
Peak LHR $\leq$ 21 KW/ft

The Instantaneous Closure of a Single MSIV event is described in Chapter 15.1.36 of the SAR (Reference 1-1).

Impact of Changes

The RSGs result in higher steam generator heat transfer area and pressures. Since for an ASGT event, one generator's load is lost and the other attempts to supply full load, a T_{cold} asymmetry is introduced across the core. The greater the T_{cold} asymmetry, the larger the radial power distortion across the core and the larger the thermal margin degradation. Higher steam generator heat transfer area and pressures affect temperature asymmetry across the core, which induce a radial power asymmetry across the core.

The increase in the most negative MTC (more negative) value results in a larger radial power distortion for a given difference in T_{cold} across the core. A larger radial power distortion results in a larger loss of thermal margin during the event. This results in higher thermal margin requirements.

An increase in minimum RCS flow has a very small impact on the analysis.

Analysis Overview

The methodology used in this analysis is the same as that used in the current analysis.

This analysis has utilized the CENTS computer code for the transient analysis simulation. The minimum DNBR evaluation was determined using the CETOP code.

Input parameters from Table 1.7-1 and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The BOC Doppler curve in Figure 1.0.2-2 was assumed.

2. A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 1.0.2 of this enclosure were assumed.

3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. A CEA worth of -4.5% $\Delta\rho$ was conservatively assumed.

4. A CPC ASGT Trip setpoint of 11°F was assumed. Cold and hot leg RTD response times of 8 seconds and 13 seconds, respectively, were accounted for along with a CPC trip delay time of 0.60 seconds.

5. The analysis was performed at 90% of rated power and assumed a nominal RCS pressure of 2200 psia.

6. An increase in core rated power to 3026 MWt rated was assumed.

7. The most negative MTC of -3.8×10^{-4} $\Delta\rho$/°F was assumed with 10% plugging assumed in the affected steam generator. This results in the largest radial power distortion in the core due to the core temperature asymmetry.

8. Installation of the RSGs was assumed.

9. An RCS flow of 315,560 gpm was assumed.

Table 1.7-1 lists the initial input assumptions for the ASGT event.

Analysis Results

For the limiting ASGT event, the minimum DNBR is greater than 1.25 and the peak power never increases above its initial value. Although the radial power distortion is large, this in combination with the core power results in a peak LHR that is less than 21 KW/ft. Thus, the SAFDLs are protected.

The NSSS and RPS responses for the ASGT event are shown in Table 1.7-2 and in Figures 1.7-1 through 1.7-5. The combined effects of the input modifications have shown that there are no adverse impacts due to the RSGs, an increase in rated power to 3026 MWt, an increase in RCS flow, and the increase in the most negative MTC (more negative) to -3.8×10^{-4} $\Delta\rho/°F$.

The ASGT Trip setpoint that is incorporated in the CPCs ensures that the acceptable DNB and CTM limits will not be exceeded during an ASGT event. The minimum thermal margin required (reserved) in COLSS for the ASGT event is set equal to or greater than the maximum thermal margin degradation observed during an ASGT event.

Only the minimum RCS flow proposed TS change affects this analysis, and as indicated above, acceptable results have been obtained.

1.8 CPC Dynamic Filters Analysis

Summary

The objective of CPC Dynamic Filter analysis is to document the impact of:

1. the RSGs,
2. an increase in rated power to 3026 MWt,
3. an increase in the most negative MTC (more negative), and
4. an increase in RCS flow

These changes will affect the dynamics of the transients, which will impact those events that lead to a reactor trip. The CPCs and RPS assure that a reactor trip will occur before the DNB and centerline-to-melt SAFDLs are exceeded.

This analysis results in no changes to the CPC filter coefficients and the corresponding correction factors. This is valid for both Cycle 15 and for the increase in rated power to 3026 MWt.

The only proposed TS change, which affects this analysis, is the increase in minimum RCS flow.

General Description of the Event

The CPCs monitor key DNB and Centerline-to-Melt (CTM) parameters. Based on these input parameters, the CPCs perform on-line calculations to determine when a SAFDL is expected to be violated. For the AOOs, which are a sub-class of the SAR DBEs, CPCs must ensure that the SAFDLs for DNB and CTM are protected.

This safety analysis evaluates the Increase Power Filter and the Increasing and Decreasing Temperature Filters along with any associated correction factors. These filters are reviewed for a set of AOOs that provide the greatest challenge to the SAFDLs. Ensuring the CPC filter responses and corresponding correction factors are conservative will result in a CPC reactor trip prior to the DNB and CTM SAFDLs being violated.

Increasing Power Filters

Of the possible rising power events (Boron Dilution, Excess Loads, Single and Bank CEA Withdrawals), the Bank CEA Withdrawal is examined because it results in the fastest rate of increasing power of all of the CPC DBEs. The Increasing Neutron Flux Filter is shown to be conservative by comparing the response of the CPC compensated core average heat flux to the actual rate of core heat flux increase. For the Neutron Flux Filter to be conservative, the CPC calibrated heat flux should be greater than the actual core heat flux.

Increasing RCS Temperature Filters

Increasing temperature that is not driven by a power increase can be caused by decreased heat removal events. Several potential decreasing heat removal AOOs are part of the CPC DBEs. A loss of feedwater or a loss of load each decreases the rate of heat removal. The loss of load is the more adverse heatup scenario.

The CPC filters provide two RCS temperature indications, T_{CMIN} (minimum cold leg temperature) and T_{CMAX} (maximum cold leg temperature), that are used in the protective calculations.

T_{CMAX} is used as the core inlet temperature for the CPCs DNBR calculation. To be conservative, the value of T_{CMAX} should be larger than the 'actual' core inlet temperature.

T_{CMIN} is used to adjust the raw neutron power signal for downcomer temperature shadowing. To be conservative, the value of T_{CMIN} should be less than the actual RCS temperature existing in the downcomer region of the reactor vessel at any given time in the transient.

The CPC lead and lag temperature filters take the Cold Leg RTD signals and adjust them to obtain the desired conservative direction of T_{CMIN} and T_{CMAX}. The Loss of Load is selected as the CPC DBE with which to examine these filters for transients resulting in an increase in RCS temperatures.

Decreasing RCS Temperature Filters

Decreasing temperature that is not driven by a power reduction can be caused by an excess load event. A spectrum of possible excess loads could be imposed upon the NSSS by the secondary system. An increase in feedwater flow or a decrease in feedwater temperature has the potential to increase the heat demand on the primary system. A single SDBCS valve has the capability of imposing an increase of ~12% of rated steam flow. A change in the position of a turbine admission valve has the potential to result in larger variations in the steam demand from the initial conditions.

The CPC filters provide two RCS temperature indications, T_{CMIN} and T_{CMAX}, that are used in the protective calculations.

T_{CMAX} is used as the core inlet temperature for the CPC DNBR calculation. To be conservative, the value of T_{CMAX} should be greater than the actual core inlet temperature.

T_{CMIN} is used to adjust the raw neutron power signal for downcomer temperature shadowing. To be conservative, the value of T_{CMIN} should be less than the actual RCS temperature existing in the downcomer region of the reactor vessel at any given time in the transient.

The CPC lead and lag temperature filters take the Cold Leg RTD signals and adjust them to obtain the desired conservative direction of T_{CMIN} and T_{CMAX}. The Excess Load Event is selected as the CPC DBE with which to examine these filters for transients resulting in decreasing RCS temperatures.

A spectrum of potential turbine driven increases in steam flow is analyzed to ensure that the filters are conservative in the decreasing temperature direction over a spectrum of possible power-to-load imbalances. For HFP conditions the following spectrum of excess load increases were analyzed:

1. Turbine demand from 80% to 125%.
2. Turbine demand from 80% to 110%.

Purpose of Analysis and Acceptance Criteria

The objective of this analysis is to ensure that various CPC RCS temperature and core power filters installed at ANO-2 are adequate to provide protection given the RSGs and power uprate. This analysis also demonstrates adequate protection if the extent of steam generator tube plugging reaches 10% of the total number of steam generator U-tubes. The CPC filters that fall within the scope of this analysis are:

1. The filters on increasing Core Power
2. The filters on increasing RCS Temperatures
3. The filters on decreasing RCS Temperatures

The criteria for the DBEs protected by the CPCs (e.g., AOOs) consist of the following:

DNBR $\geq$ DNB SAFDL
Peak LHR $\leq$ 21 KW/ft

This analysis does not directly address the above criteria. Instead, the result of this analysis is a set of filter coefficients and correction factors that act upon various parameters that go into determining if a CPC Low DNBR or High LPD Trip should occur. These filter coefficients and correction factors ensure that certain parameters used in the CPCs trip decision are conservative.

Impact of Changes

The impact of the changes would be the same as those described in Sections 1.1.2 (Uncontrolled CEA Withdrawal from Critical Conditions), 1.4.1 (Loss of External Load and/or Turbine Trip, and 1.5.2 (Excess Heat Removal due to Main Steam System Valve Malfunction) of this enclosure.

Analysis Overview

This analysis used the CENTS computer code for the transient analysis simulation. The minimum DNBR evaluation used the CETOP code.

Previously defined input parameters and the bounding physics data from Section 1.0.2 of this enclosure have been incorporated in this analysis with the following clarifications:

1. The BOC Doppler curve in Figure 1.0.2-2 was assumed.

2. Both BOC and EOC delayed neutron fractions and neutron lifetimes consistent with those defined in Section 1.0.2 of this enclosure were assumed, depending on the event.

3. The CEA reactivity insertion curve in Figure 1.0.2-3 was assumed. This curve accounts for a 0.6 second holding coil delay. CEA worths dependent on initial core power were conservatively assumed.

4. Parametric in core power from 20% to 100% power based on a rated core power of 3026 MWt was assumed for the decreasing RCS temperature filters and increasing power filters analysis.

5. An MTC dependent on initial power level was assumed (see Figure 1.0.2-1).

6. Installation of the RSGs was assumed.

Analysis Results

The CPC transient filters analysis was performed to assure that the CPCs could conservatively respond to the following events with the changes due to the RSGs, an increase in rated power, an increase in RCS flow, and an increase in negative MTC (more negative):

1. The cooldown associated with an excess heat removal event,
2. The heatup associated with a loss of load event; and,
3. The power increase associated with CEA bank withdrawal.

The CPC transient filters analysis verifies that the CPC adjusted process parameters are conservative with respect to the expected values for a given transient event. The CPC coefficients are adjusted as necessary to assure the CPCs action prevents SAFDL violation during the transient. This analysis included parametric studies on RCS flow and tube plugging to determine the limiting values of these inputs.

The results of the analysis verified proper response to the significant overcooling, heatup, and power increasing transients and conservative CPC actions. Consequently, the effects of the RSGs, the increase in rated power, the increase in RCS flow, and the increase in the negative MTC value (more negative) on the significant excess heat removal, heatup, and power increase events have been evaluated. This evaluation ensures that the CPCs and RPS will provide the necessary trip functions to protect the SAFDLs.

References for RSGs Report Section 1

1-1 "Arkansas Nuclear One Unit 2 Safety Analysis Report", Amendment 15, Docket #50-368.

1-2 "Technical Manual for the CENTS Code," CENPD 282-P-A, February 1991.

1-3 "CETOP-D Code Structures and Modeling Methods for Arkansas Nuclear One - Unit 2, CEN-214(A)-P, July 1982.

1-4 "A Multi-Dimensional Space-Time Kinetics Code for PWR Transients", CENPD-188-A, July 1976.

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1-10 "Safety Evaluation by the Office of Nuclear Reactor Regulation Supporting Amendment No. 24 to Facility Operating License No. NPF-6 Arkansas Power and Light Company, Arkansas Nuclear One-Unit No. 2, Docket No. 50-368."

1-11 "C-E Method for Control Element Assembly Ejection Analysis", CENPD-190-A, January 1976.

1-12 NRC letter from Herbert N. Berkow, NRC to A. E. Scherer of CE, "Acceptance for Referencing of Licensing Topical Report CEN-308-P and CEN-310-P, "CPC/CEAC Software Modifications for the CPC Improvement Program" and "CPC and Methodology Changes for the CPC Improvement Program", March 12, 1986.

1-13 "RELAP5MOD3.1/MOD3 Code Manual Volumes I, II, III and IV", NUREG/CR-5535.

1-14 MacBeth, R.V., "An Appraisal of Forced Convection Burnout Data", Proc. Inst. Mech. Engrs., Vol. 180, Pt. 3C, 1965-1966.

Table 1.0-1

NON-LOCA DESIGN BASIS EVENTS CYCLE 15 ANALYSIS STATUS

RSGs Section	SAR Section	Section Title	Analysis Effort
1.1.1	15.1.1	Uncontrolled CEA Withdrawal from a Subcritical Condition	Evaluated
1.1.2	15.1.2	Uncontrolled CEA Withdrawal from Critical Conditions Hot Zero Power (HZP) Hot Full Power (HFP)	 Evaluated Evaluated
1.1.3	15.1.3	CEA Misoperation	Evaluated
1.2	15.1.4	Uncontrolled Boron Dilution Incident Modes 1 and 2 Modes 3, 4, 5, and 6	 Evaluated Evaluated
1.3	15.1.5	Total and Partial Loss of RCS Forced Flow Four Pump Loss of Flow Seized Rotor	 Evaluated Evaluated
None	15.1.6	Idle Loop Startup	Not Reanalyzed
1.4.1	15.1.7	Loss of External Load and/or Turbine Trip	Reanalyzed
1.4.2	15.1.8	Loss of Normal Feedwater Flow	Reanalyzed
1.4.3	15.1.9	Loss of All Normal and Preferred AC Power to the Station Auxiliaries	Evaluated
1.5.1 & 1.5.2	15.1.10	Excess Heat Removal Due to Secondary System Malfunction	Reanalyzed
None	15.1.11	Failure of the Regulating Instrumentation	Not Applicable
None	15.1.12	Internal and External Events Including Major and Minor Fires, Floods, Storms, and Earthquakes	Not Reanalyzed
None	15.1.13	Major Rupture of Pipes Containing Reactor Coolant up to and Including Double-Ended Rupture of Largest Pipe in the Reactor Coolant System (LOCA)	See Enclosure 3
1.5.3	15.1.14	Major Secondary System Pipe Breaks with or without a Concurrent Loss of AC Power Main Steam Line Break (MSLB)	Reanalyzed
1.4.4		Feedwater Line Break (FWLB)	Reanalyzed

Table 1.0-1 *(Continued)*

NON-LOCA DESIGN BASIS EVENTS CYCLE 15 ANALYSIS STATUS

RSGs Section	SAR Section	Section Title	Analysis Effort
None	15.1.15	Inadvertent Loading of a Fuel Assembly into the Improper Position	Not Reanalyzed
None	15.1.16	Waste Gas Decay Tank Leakage or Rupture	Not Reanalyzed
None	15.1.17	Failure of Air Ejector Lines (BWR)	Not Applicable
1.6	15.1.18	Steam Generator Tube Rupture with or without a Concurrent Loss of AC Power (SGTR)	Evaluated
None	15.1.19	Failure of Charcoal of Cryogenic System (BWR)	Not Applicable
1.1.4	15.1.20	CEA Ejection HZP HFP	 Evaluated Evaluated
None	15.1.21	The Spectrum of Rod Drop Accidents (BWR)	Not Applicable
None	15.1.22	Break in Instrument Line or Other Lines from Reactor Coolant Pressure Boundary that Penetrate Containment	Not Reanalyzed
None	15.1.23	Fuel Handling Accident	Not Reanalyzed
None	15.1.24	Small Spills or Leaks of Radioactive Material Outside Containment	Not Reanalyzed
None	15.1.25	Fuel Cladding Failure Combined with Steam Generator Leak	Not Reanalyzed
None	15.1.26	Control Room Uninhabitability	Not Reanalyzed
None	15.1.27	Failure or Over pressurization of Low Pressure Residual Heat Removal System	Not Reanalyzed
(see 1.4.1)	15.1.28	Loss of Condenser Vacuum (LOCV)	Not Reanalyzed (SAR 15.1.7)
(see 1.4.1)	15.1.29	Turbine Trip with Coincident Failure of Turbine Bypass Valves to Open	Not Reanalyzed (SAR 15.1.7)

Table 1.0-1 ***(Continued)***

NON-LOCA DESIGN BASIS EVENTS CYCLE 15 ANALYSIS STATUS

RSGs Section	SAR Section	Section Title	Analysis Effort
None	15.1.30	Loss of Service Water System	Not Reanalyzed
None	15.1.31	Loss of one DC System	Not Reanalyzed
None	15.1.32	Inadvertent Operation of ECCS During Power Operation	Not Reanalyzed
None	15.1.33	Turbine Trip with Failure of Generator Breaker to Open	Not Reanalyzed
None	15.1.34	Loss of Instrument Air System	Not Reanalyzed
None	15.1.35	Malfunction of Turbine Gland Sealing System	Not Reanalyzed
1.7	15.1.36	Transients Resulting from the Instantaneous Closure of a Single MSIV	Reanalyzed

Table 1.0.1-1		
Initial Conditions to Safety Analysis		
Core Parameter	**Units**	**Analysis Value**
Core Power (nominal / with uncertainty) Rated Uprated	MWt	 2815 / 2900 3026 / 3087
Reactor Coolant Pump (total) Nominal Maximum	MWt	 10 18
Steady State Core Inlet Temperature (including uncertainty) Hot Full Power Hot Zero Power	°F	 $540.0 \leq Tin \leq 556.7$ $523.0 \leq Tin \leq 552.0$
Steady State Pressurizer Pressure (including uncertainty) (1)	psia	$2000 \leq$ Prz Press ≤ 2300
Steady State RCS Flow (including uncertainty)	gpm	$315{,}560 \leq$ Flow $\leq 386{,}400$
Steady State Axial Shape	asi	$-0.3 \leq$ ASI $\leq +0.3$
Moderator Temperature Coefficient	°F/Δρ	Figure 1.0.2-1
Maximum Linear Heat Rate Rated Uprated	KW/ft	 13.5 13.7
CEA Insertion Time	Position vs. Time	Figure 1.0.2-4
Steady State Linear Heat Rate for Centerline Melt Limit	KW/ft	21.0
DNB SAFDL CE-1 MacBeth		 1.25 1.30

Table 1.0.1-1 *(Continued)*		
Initial Conditions to Safety Analysis		
Core Parameter	**Units**	**Analysis Value**
Pressurizer Safety Valves		
Opening Setpoint	psia	2500
Tolerance	%	3[2]
Main Steam Safety Valves		
Opening Setpoints	psig	
Bank 1 @		1078
Banks 2 and 3 @		1105
Banks 4 and 5 @		1132
Tolerance	%	3

(1) Initial pressures are input as pressurizer pressure, but are referred to as RCS pressure in the individual event input Tables. Plots are of RCS pressure. Therefore the initial values on the plots are slightly higher by 20 to 30 psi than the value quoted in the "Assumptions" Tables.

(2) A tolerance of 3.2% or 3.5% has been conservatively used in some analyses.

Table 1.0.1-2		
RPS/ESFAS Setpoints and Response Times		
RPS / ESFAS Signal	**Analysis Setpoint, Units**	**Response Time, seconds**
High Containment Pressure RPS trip	20.7 psia	1.2[6]
Low Pressurizer Pressure RPS trip SIAS HPSI	 1400 psia 1400 psia [5]	 1.2 40 [3]
High Pressurizer Pressure, Normal Harsh	 2392 psia 2415 psia	0.65
Low Steam Generator Level, RPS trip Normal Abnormal EFAS trip Normal Harsh (FWLB only) EFW Train A EFW Train B	 9% of NR 6% of NR 9% of NR 0% of NR	 1.3 97.4 112.4[3]/97.4[4]
EFAS Isolation, psid EFW Train A EFW Train B	220 psid	1.4 [1] 97.4 112.4[3]/97.4[4]

Table 1.0.1-2 *(Continued)*

RPS/ESFAS Setpoints and Response Times

RPS / ESFAS Signal	Analysis Setpoint, Units	Response Time, seconds
Low Steam Generator Pressure		
RPS trip		1.3
Normal	693 psia	
MSIS		1.4 (1)
Normal	693 psia	
Harsh	658 psia	
Main Steam Isolation		4.9
Feedwater Isolation Valves		41.4(3)/26.4(4)
Feedwater Back-up Valves		34.9(3)/19.9(4)
Core Protection Calculators		
Low RCP Shaft Speed	0.95	0.4
ASGT function - ΔTcold	11°F	0.4 (2)
Variable Overpower Trip		0.4 (2)
Floor	30% of rated	
Ceiling	110% of rated	
DELSPV (difference)	10% of rated	
SPVMAX (rate),	1%/minute	
Effective RTD Time Constant, seconds		
Hot Leg		13
Cold Leg		8

(1) Included as part of the overall ESFAS response time as part of the specific ESFAS function, which is defined as part of the individual event section (e.g., the 4.9 second MSIV closure time includes 1.4 second MSIS response time).
(2) Does not include two cycles of 0.1 seconds for the CPCs UPDATE subroutine execution time.
(3) Diesel generator starting and sequence loading delays included.
(4) Diesel generator starting delay not included, sequence loading delays included. Offsite power available.
(5) SGTR assumes 1600 psia.
(6) A response time of 1.59 seconds has been conservatively used for some analyses.

TABLE 1.0.4-1
Fuel Pin Activities

Isotope	Maximum Activity (Ci/pin)
I-131	2.002E+03
I-132	2.882E+03
I-133	4.072E+03
I-134	4.517E+03
I-135	3.788E+03
Kr-85	2.281E+01
Kr-85m	6.473E+02
Kr-87	1.279E+03
Kr-88	1.805E+03
Xe-131m	2.249E+01
Xe-133	4.055E+03
Xe-133m	1.263E+02
Xe-135	1.055E+03
Xe-135m	7.993E+02
Xe-138	3.540E+03

TABLE 1.0.4-2A
ICRP-30 DATA FOR ISOTOPES

Isotope	Thyroid DCF (Rem/Ci)	Whole Body γ DCF (Rem-m^3/Ci-s)
I-131	1.1E+06	-
I-132	6.3E+03	-
I-133	1.8E+05	-
I-134	1.1E+03	-
I-135	3.1E+04	-
Kr-85		3.31E-04
Kr-85m		2.31E-02
Kr-87		1.33E-01
Kr-88		3.38E-01
Xe-131m		1.25E-03
Xe-133		4.96E-03
Xe-133m		4.29E-03
Xe-135		3.59E-02
Xe-135m		6.37E-02
Xe-138		1.87E-01

TABLE 1.0.4-2B
ICRP-2 DATA FOR ISOTOPES

Isotope	Thyroid DCF (Rem/Ci)	Whole Body γ DCF (Rem-m^3/Ci-s)	Whole Body β DCF (Rem-m^3/Ci-s)
I-131	1.48E+06	9.30E-02	4.49E-02
I-132	5.35E+04	5.98E-01	9.71E-02
I-133	4.00E+05	1.60E-01	9.38E-02
I-134	2.50E+04	4.58E-01	1.26E-01
I-135	1.24E+05	4.43E-01	7.08E-02
Kr-85		5.28E-04	5.11E-02
Kr-85m		3.80E-02	5.59E-02
Kr-87		3.55E-01	2.42E-01
Kr-88		4.35E-01	7.82E-02
Xe-131m		6.78E-03	3.15E-02
Xe-133		1.24E-02	3.36E-02
Xe-133m		1.42E-02	4.07E-02
Xe-135		6.20E-02	7.27E-02
Xe-135m		1.07E-01	2.25E-02
Xe-138		2.74E-01	2.76E-01

TABLE 1.0.4-3

Atmospheric Dilution Factors (χ/Q, s/m^3)

Time Period	EAB	LPZ
0-2 hr	6.5E-04	-
0-8 hr	-	3.1E-05
8-24 hr	-	3.6E-06
1-4 days	-	2.3E-06
4-30 days	-	1.4E-06

TABLE 1.0.4-4

Breathing Rates

Time After Accident	Breathing Rate, m^3/s
0-8 hr	3.47E-04
8-24 hr	1.75E-04
1-30 days	2.32E-04

TABLE 1.3.1-1

FOUR REACTOR COOLANT PUMP FLOW COASTDOWN
RESULTING FROM AN ELECTRICAL FAILURE

Time (Seconds)	Core Flow Rate (Normalized)
0.0	1.0000
0.5	0.9715
1.0	0.9323
1.5	0.8953
2.0	0.8607
2.5	0.8293
3.0	0.7996
3.5	0.7721
4.0	0.7465
4.5	0.7225
5.0	0.7000
10.0	0.5349

TABLE 1.3.1-2

SEQUENCE OF EVENTS
FOR THE 4-PUMP LOSS OF COOLANT FLOW ANALYSIS

Time, seconds	Event	Setpoint or Value
0.0	Loss of power to all four reactor coolant pumps	------
0.8	CPC Low RCP Speed Trip (95%)	95% nominal speed
1.1 *	Trip breakers open	------
1.7 *	Shutdown CEAs begin to drop into core	------
2.8 *	Minimum CE-1 DNBR	1.29 **

* For Cycle 15 the CPC Low RCP Speed Trip response time was increased to 0.4 seconds. Hence, all values have increased by 0.1 seconds.

** For Cycle 15 adjustments this value decreased to 1.277.

TABLE 1.3.2-1

RADIOLOGICAL DOSE RESULTS FOR CYCLE 15
REACTOR COOLANT PUMP SHAFT SEIZURE
ASSUMING 14% FUEL FAILURE

Radiological Dose	**No Iodine Spiking, Rem**
Thyroid	
EAB	5
LPZ	3
Whole Body	
EAB	1
LPZ	0.1

TABLE 1.4.1-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT
LOSS OF CONDENSER VACUUM

Parameter	Units	Conservative Assumptions
Initial Core Power Level	MWt	3087
RCP Heat	MWt	18
Core Inlet Coolant Temperature	°F	540.0
Reactor Coolant System Flow	gpm	386,400
Reactor Coolant System Pressure	psia	2000
Steam Generator Pressure	psia	848
Moderator Temperature Coefficient	10^{-4} $\Delta\rho$/°F	0.0
Fuel Temperature Coefficient	-	BOC
CEA Worth on Trip	10^{-2} $\Delta\rho$	-5.0
Steam Generator Tube Plugging	%	0
Tolerance on MSSV Setpoint	%	3
Tolerance on PSV Setpoint	%	+3.2
Steam Bypass System	-	Inoperative
Feedwater Regulating System	-	Manual

TABLE 1.4.1-2

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT
LOSS OF CONDENSER VACUUM

Time (seconds)	Event	Setpoint or Value
0.0	Loss of Condenser Vacuum, Turbine Stop Valves Close, Main Feedwater Valves Close	---
7.63	High Pressurizer Pressure Trip Condition Occurs	2392 psia
8.28	Trip Breakers Open	---
8.88	CEAs Begin to Drop	---
9.05	Main Steam Safety Valves Open	1125.48 psia
10.10	Pressurizer Safety Valves Open	2580 psia
10.53	Maximum RCS Pressure Occurs	2688 psia (1)
12.10	Pressurizer Safety Valves Close	2503 psia
17.10	Peak Secondary Side Pressure (Steam Dome)	1180 psia

(1) Includes reactor coolant pump head

TABLE 1.4.1-3

RESULTS FOR CYCLE 15
LOSS OF CONDENSER VACUUM
INOPERABLE MSSV CASES

Maximum Number of MSSVs Inoperable	**MTC 10^{-4} Δρ/°F**	**Power Level (%)**
1	-2.1	97
	-1.3	93
	-0.6	89
	0	84

Maximum Number of MSSVs Inoperable Per Steam Generator	**MTC 10^{-4} Δρ/°F**	**Power Level (%)**
1	-2.5	93
	-1.6	89
	-0.81	84
	-0.17	80
	0	76
2	n/a	43
3	n/a	25

TABLE 1.4.2-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT
LOSS OF NORMAL FEEDWATER FLOW

Parameter	Units	Conservative Assumptions
Initial Core Power Level	MWt	3087
RCP Heat	MWt	18
Core Inlet Coolant Temperature	°F	556.7
Reactor Coolant System Flow	gpm	315,560
Reactor Coolant System Pressure	psia	2000
Steam Generator Pressure	psia	1000
Moderator Temperature Coefficient	10^{-4} $\Delta\rho$/°F	-3.8
Fuel Temperature Coefficient	-	EOC
CEA Worth on Trip	10^{-2} $\Delta\rho$	-5.0
Steam Bypass System	-	Automatic
Feedwater Regulating System	-	Malfunction

TABLE 1.4.2-2

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT
LOSS OF NORMAL FEEDWATER FLOW

Time (seconds)	Event	Setpoint or Value
0.0	LOFW occurs	-
27.4	Steam Dump and Bypass Begins to Open	-
49.2	Low Steam Generator Level Trip Condition occurs	9% of NR
50.5	Trip Breakers Open	-
51.1	CEAs Begin to Drop, MSSVs Open	- 1054.45 psia
53.5	Peak RCS Pressure Occurs	2153 psia
54.5	Peak Steam Generator Pressure Occurs	1091 psia
89.3	MSSVs Close	1002 psia
146.6	EFW Begins to Inject	-
212.0	Minimum Liquid Inventory in Steam Generator A	-
288.0	Minimum Liquid Inventory in Steam Generator B	-

TABLE 1.4.4-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT
FEEDWATER LINE BREAK

Parameter	Units	Conservative Assumptions
Initial Core Power Level	MWt	2900
RCP Heat	MWt	18
Core Inlet Coolant Temperature	°F	556.7
Reactor Coolant System Flow	gpm	315,560
Reactor Coolant System Pressure	psia	2000
Steam Generator Pressure	psia	1000
Moderator Temperature Coefficient	10^{-4} $\Delta\rho$/°F	-0.2
Fuel Temperature Coefficient	-	BOC
CEA Worth on Trip	10^{-2} $\Delta\rho$	-5.0
Steam Generator Tube Plugging	%	0
Tolerance on MSSV Setpoint	%	+3
Tolerance on PSV Setpoint	%	+3.2

TABLE 1.4.4-2

PRINCIPAL RESULTS FOR CYCLE 15 AT 3026 MWT
FEEDWATER LINE BREAK

Time (seconds)	Event	Setpoint or Value
0.0	Feedwater Line Break Occurs	-
44.9	Low SG Level Trip Occurs on Intact SG	6% of NR
45.4	Affected Steam Generator Empties	-
45.5	High Pressurizer Pressure Trip Condition Occurs	2415 psia
46.2	Trip Circuit Breakers Open, Loss of AC Power Occurs, RCPs Begin Coastdown	-
46.8	CEAs Begin to Drop	-
47.9	Pressurizer Safety Valves Open	2580 psia
48.1	EFAS, EFW Pumps Start	0% of NR
49.2	Peak RCS Pressure Occurs	2694 psia [(1)]
53.9	Pressurizer Safety Valves Close	2502.5 psia
128.2	SG Low Pressure Trip and MSIS Initiated	658 psia
129.6	Main Steam Isolation Valves Begin to Close	-
133.1	Main Steam Isolation Valve Closed	-
139.4	Pressure Difference Between Steam Generators, EFAS Signal Opens EFW Valves to Feed Intact SG	220 psid
175.8	Emergency Feedwater Enters Intact SG	-
176.1	Minimum Liquid Mass in the Intact SG	13,140 lbm
303.7	MSSVs Open on Intact SG (long term cycling start)	1125.5 psia
2000	Case Terminated	-

(1) Includes reactor coolant pump head.

TABLE 1.4.4-3

RADIOLOGICAL DOSE RESULTS FOR
THE FEEDWATER LINE BREAK EVENT

Radiological Dose	**No Iodine Spiking, Rem**
Thyroid	
EAB	9
LPZ	0.5
Whole Body	
EAB	< 0.1
LPZ	< 0.1

TABLE 1.5.1-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT
FEEDWATER SYSTEM MALFUNCTION

Parameter	Units	Conservative Assumptions
Initial Core Power Level	MWt	3087
RCP Heat	MWt	10
Core Inlet Coolant Temperature	°F	556.7
Reactor Coolant System Flow	gpm	315,560
Reactor Coolant System Pressure	psia	2300
Steam Generator Pressure	psia	1003
Moderator Temperature Coefficient	10^{-4} $\Delta\rho$/°F	-3.8
Fuel Temperature Coefficient	-	BOC
CEA Worth on Trip	10^{-2} $\Delta\rho$	-5.0
Steam Bypass System	-	Automatic
Feedwater Regulating System	-	Malfunction
Feedwater Energy Reduction	BTU/lbm	152

TABLE 1.5.1-2

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT
FEEDWATER SYSTEM MALFUNCTION

Time (seconds)	Event	Setpoint or Value
0.0	Failure Occurs in Feedwater Control System	-
0.5	Symmetric Feedwater Flow to Both SGs Increases to Approximately 160%	-
18.2	CPC VOPT Condition Occurs	112%
18.8	Trip Breakers Open	-
19.4	CEAs Begin to Drop	-
19.5	Maximum Core Power Occurs, Minimum DNBR	114% > 1.25
19.9	Dump Valves Fully Open	-
28.3	Dump Valves Begin to Close	-

TABLE 1.5.2-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT
STEAM BYPASS SYSTEM MALFUNCTION

Parameter	Units	Conservative Assumptions
Initial Core Power Level	MWt	3087
RCP Heat	MWt	10
Core Inlet Coolant Temperature	°F	556.7
Reactor Coolant System Flow	gpm	315,560
Reactor Coolant System Pressure	psia	2300
Steam Generator Pressure	psia	1003
Moderator Temperature Coefficient	10^{-4} $\Delta\rho$/°F	-3.8
Fuel Temperature Coefficient	-	BOC
CEA Worth on Trip	10^{-2} $\Delta\rho$	-5.0
Steam Bypass System	-	Malfunction
Feedwater Regulating System	-	Manual

TABLE 1.5.2-2

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT
STEAM BYPASS SYSTEM MALFUNCTION

Time (seconds)	Event	Setpoint or Value
0.0	One Atmospheric Dump Valve Opens	-
17.9	CPC VOPT condition Occurs	112%
18.5	Trip Breakers Open	-
19.1	CEAs Begin to Drop	-
19.3	Maximum Core Power Occurs, Minimum DNBR	113% of rated > 1.25
21.5	Peak RCS Pressure Occurs	2247 psia
23.5	Steam Generator Safety Valves Open	1061 psia
24.9	Peak Steam Generator Pressure Occurs	1086 psia
40.2	Steam Generator Safety Valves Close	1003 psia
55.1	Pressurizer Emptied, SIAS Setpoint Achieved	1400 psia
119.1	Boron Reaches Injection Nozzle	-
188.3	Low Steam Generator Pressure, MSIS Initiated	693 psia
193.2	Main Steam Isolation Valves Fully Closed	-
214.7	Main Feedwater Isolation Valves Fully Closed	-
209.5	Minimum RCS Pressure	887 psia
1800	Operator Assumes Control of Plant	-

TABLE 1.5.3-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT STEAM LINE BREAK ANALYSIS
FROM HOT FULL POWER TO HOT ZERO POWER

		Assumptions	
Parameter	**Units**	**Hot Full Power**	**Hot Zero Power**
Initial Core Power Level	MWt	3087	1
RCP Heat	MWt	10	10
Initial Core Inlet Coolant Temperature	°F	556.7	552
Initial Reactor Coolant System Flow	gpm	315,560	314,682
Initial Reactor Coolant System Pressure	psia	2300	2300
Initial Steam Generator Pressure	psia	1001	1065
Moderator Temperature Coefficient	10^{-4} Δρ/°F	-3.8 (1)	-3.8 (1)
Fuel Temperature Coefficient	-	EOC	EOC
CEA Worth on Trip	10^{-2} Δρ	-6.84	-4.84
MTC Multiplier	-	1.0	1.0
Feedwater Regulating System	-	Automatic	Automatic

(1) See Figure 1.5.3-1

TABLE 1.5.3-2

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT STEAM LINE BREAK
HOT FULL POWER WITH LOSS OF AC

Time, (seconds)	Event	Setpoint or Value
0.0	Steam Line Break Occurs Loss of AC Power Occurs RCPs Begin Coastdown	-
0.51	CPC Low RCP Speed Trip Signal	95% of Rated Speed
1.51	Trip Breakers Open	-
2.11	CEAs Begin to Drop	-
14.16	MSIS Setpoint Achieved	658 psia
15.58	MSIVs Begin to Close	-
19.08	Complete Closure of the MSIV	-
25.21	EFW System Actuated	41% of NR
26.98	Pressurizer Empties	< 0.5 ft
27.80	SG Delta Pressure Achieved	220 psid
37.45	SIAS Setpoint Achieved	1400 psia
50.21	Turbine-Driven EFW Pump Feeding Intact SG	-
77.45	SIAS Pumps Begin Injection	-
113.21	Motor-Driven EFW Pump Begins to Feed Intact SG	-
133.45	Boron Reaches RCS	-
281.60	Maximum Post-Trip Reactivity (1)	0.0173 %$\Delta\rho$
286.56	Time of Minimum DNBR, (MacBeth) (1)	1.70

TABLE 1.5.3-2 *(Continued)*

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT STEAM LINE BREAK
HOT FULL POWER WITH LOSS OF AC

Time, (seconds)	Event	Setpoint or Value
288.04	Maximum Post-Trip Fission Power [1]	2.76% of 3026 MWt
491.12	Affected SG Empties, (liquid mass in evaporator)	< 1000 lbm
600	End of Calculation	-
1800	Operator Initiates Cooldown (not simulated)	-

(1) For Cycle 15, the HFP with loss of offsite power sequence of events is the same with the exact timing of the event being within 2 seconds of the times shown above.

The Cycle 15 maximum post-trip fission power is 3.39% of 2815 MWt, the minimum MacBeth DNBR is 1.56, and the maximum post-trip reactivity is 0.0211.

TABLE 1.5.3-3

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT STEAM LINE BREAK HOT FULL POWER WITH AC AVAILABLE INSIDE CONTAINMENT

Time, (seconds)	Event	Setpoint or Value
0.0	Steam line break occurs	-
2.01	Containment High Pressure Trip Signal	20.7 psia
3.59	Trip Breakers Open	-
4.19	CEAs Begin to Drop	-
16.59	MSIS Setpoint Achieved	658 psia
17.99	MSIVs Begin to Close	-
21.49	Complete Closure of the MSIV	-
22.16	Pressurizer Empties	< 0.5 ft
24.46	SIAS Setpoint Achieved	1400 psia
30.76	EFW System Actuated	41.0% of NR
32.59	SG Delta Pressure Achieved	220 psid
55.78	Turbine-Driven EFW Pump Feeding Intact SG	-
64.46	SIAS Pumps Begin Injection	-
95.30	Boron Reaches RCS	-
113.78	Motor-Driven EFW Pump Feeding Intact SG	-
116.46	Time of Minimum DNBR, (MacBeth)	2.72
118.58	Maximum Post-Trip Fission Power	4.26% of 3026 MWt
120.54	SIT Activation Pressure Reached	550 psia

TABLE 1.5.3-3 *(Continued)*

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT STEAM LINE BREAK HOT FULL POWER WITH AC AVAILABLE INSIDE CONTAINMENT

Time, (seconds)	Event	Setpoint or Value
267.08	Maximum Post-Trip Reactivity	-0.0218% $\Delta\rho$
302.53	Affected SG Empties, (liquid mass in evaporator)	< 1000 lbm
400	End of Calculation	-
1800	Operator Initiates Cooldown (not simulated)	-

TABLE 1.5.3-4

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT STEAM LINE BREAK
HOT ZERO POWER WITH LOSS OF AC

Time, (seconds)	Event	Setpoint or Value
0.0	Steam Line Break Occurs Loss of AC power Occurs RCPs Begin Coastdown Maximum Start-Up Feed Pump Flow to Affected SG	-
0.51	CPC Low RCP Speed Trip Signal	95% of Rated Speed
1.51	Trip Breakers Open	-
2.11	CEAs Begin to Drop	-
11.66	MSIS Setpoint Achieved	658 psia
13.06	MSIVs Begin to Close	-
16.56	Complete Closure of the MSIV	-
28.20	SG Delta Pressure Achieved	220 psid
55.90	Pressurizer Empties	< 0.5 ft
61.06	SIAS Setpoint Achieved	1400 psia
63.30	EFIV Closed	-
101.06	SIAS Pumps Begin Injection	-
141.34	Boron Reaches RCS	-
400.51	Maximum Post-Trip Reactivity	+0.206% $\Delta\rho$
684.00	Time of Minimum DNBR, (MacBeth)	22.8
684.12	Time of Maximum Post-Trip Fission Power,	0.15% of 3026 MWt
900	End of calculation	-
1800	Operator Initiates Cooldown (not simulated)	-

TABLE 1.5.3-5

SEQUENCE OF EVENTS FOR THE CYCLE 15 AT 3026 MWT STEAM LINE BREAK - HOT ZERO POWER WITH AC AVAILABLE OUTSIDE CONTAINMENT

Time, (seconds)	Event	Setpoint or Value
0.0	Steam Line Break Occurs Maximum Start-Up Feed Pump Flow to Affected SG	-
11.06	Low SG Pressure Trip, MSIS Setpoint Achieved	693 psia
12.37	Trip Breakers Open	-
12.46	MSIVs Begin to Close	-
12.97	CEAs Begin to Drop	-
15.96	Complete Closure of MSIVs	-
26.60	SG Delta Pressure Achieved	220 psid
46.30	Pressurizer Empties	< 0.5 ft
47.47	EFIV Closed	-
49.42	SIAS Setpoint Achieved	1400 psia
59.82	Time of Minimum DNBR, (MacBeth)	78.9
89.42	SIAS Pumps Begin Injection	-
116.42	Boron Reaches RCS	-
125.82	SIT Activation Pressure Achieved	550 psia
233.64	Maximum Post-Trip Reactivity	-0.545% $\Delta\rho$
404.46	Affected SG Empties, (liquid mass in evaporator)	< 1000
500	End of Calculation	-
1800	Operator Initiates Cooldown (not simulated)	-

TABLE 1.5.3-6

NO IODINE SPIKE AND EVENT GENERATED IODINE SPIKE
RADIOLOGICAL DOSE RESULTS FOR MAIN STEAM LINE BREAK EVENT

Radiological Dose	No Iodine Spike, Rem	Event Generated Iodine Spike, Rem
Thyroid		
EAB	5	9
LPZ	0.3	3
Whole Body		
EAB	< 0.1	< 0.1
LPZ	< 0.1	< 0.1

TABLE 1.5.3-7

PRE-EXISTING IODINE SPIKE RADIOLOGICAL DOSE RESULTS
FOR MAIN STEAM LINE BREAK EVENT

Radiological Dose	Pre-existing Iodine Spike, Rem
Thyroid	
EAB	10
LPZ	2
Whole Body	
EAB	< 0.1
LPZ	< 0.1

TABLE 1.7-1

ASSUMPTIONS FOR CYCLE 15 AT 3026 MWT
ASYMMETRIC STEAM GENERATOR TRANSIENT EVENT

Parameter	Units	Conservative Assumptions
Initial Core Power Level	MWt	90% of 3026
Core Inlet Coolant Temperature	°F	556.7
Reactor Coolant System Flow	gpm	315,560
Reactor Coolant System Pressure	psia	2200
Initial Steam Generator Pressure	psia	978
Moderator Temperature Coefficient	10^{-4} $\Delta\rho$/°F	-3.8
Fuel Temperature Coefficient	-	BOC
CEA Worth on Trip	10^{-2} $\Delta\rho$	-4.5
Steam Generator Tube Plugging	%	10 (Affected SG Only)
Tolerance on MSSV Setpoint	%	+3.5
Axial Shape Index	asiu	-0.3

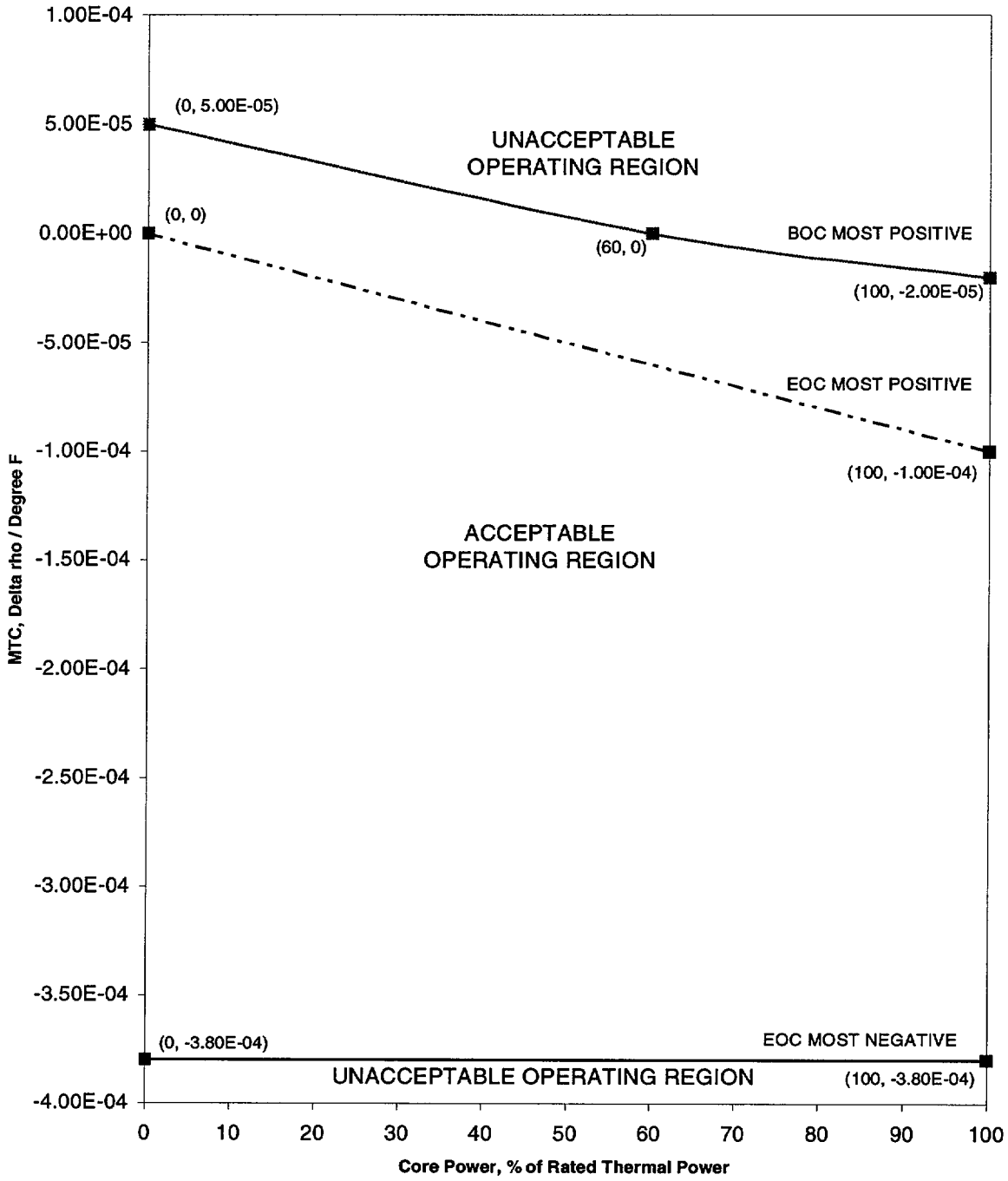
TABLE 1.7-2

SEQUENCE OF EVENTS FOR CYCLE 15 AT 3026 MWT ASYMMETRIC STEAM GENERATOR TRANSIENT EVENT

Time (seconds)	Event	Setpoint or Value
0.0	Spurious Closure of a Single MSIV	-
4.2	MSSVs Open on Affected Steam Generator	1131 psia
5.6	ASGT Trip Setpoint Achieved	11°F
6.2	Trip Breakers Open	-
6.8	CEAs Begin to Drop	-
9.2	Time of Minimum DNBR	> 1.25
12.9	Maximum Steam Generator Pressure Occurs	1192 psia

Figure 1.0.2-1

Moderator Temperature Coefficient vs. Core Power



The beginning of Cycle (BOC) MTC limit line is effective from BOC to 166.4 EFPD. From 332.5 EFPD to the End of Cycle (EOC), the lower EOC limit line is in effect. Between 166.4 EFPD and 332.5 EFPD, the positive MTC limit may be interpolated linearly with burnup

Figure 1.0.2-2

Doppler Reactivity vs. Fuel Temperature

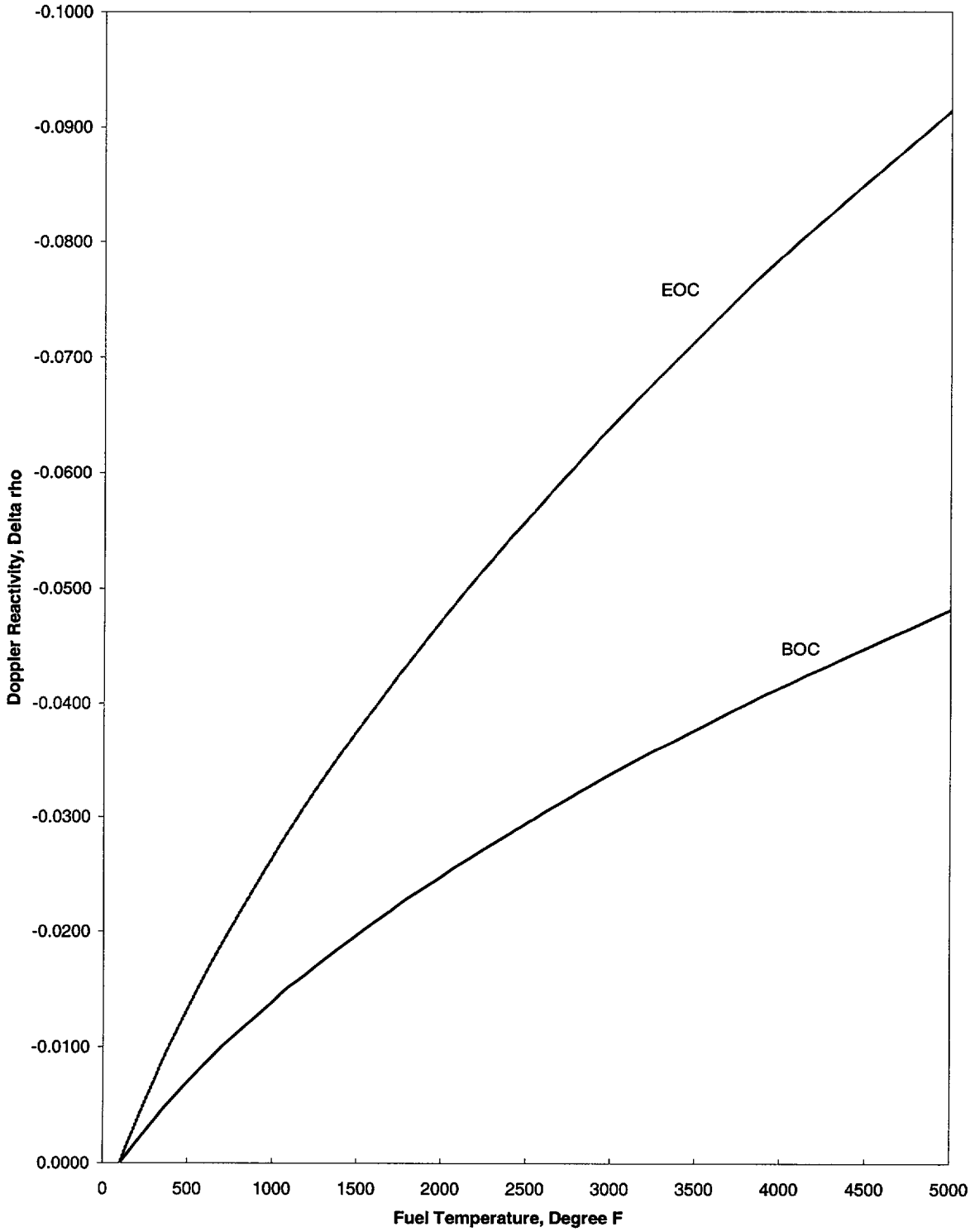


Figure 1.0.2-3

Reactivity Insertion vs. Time

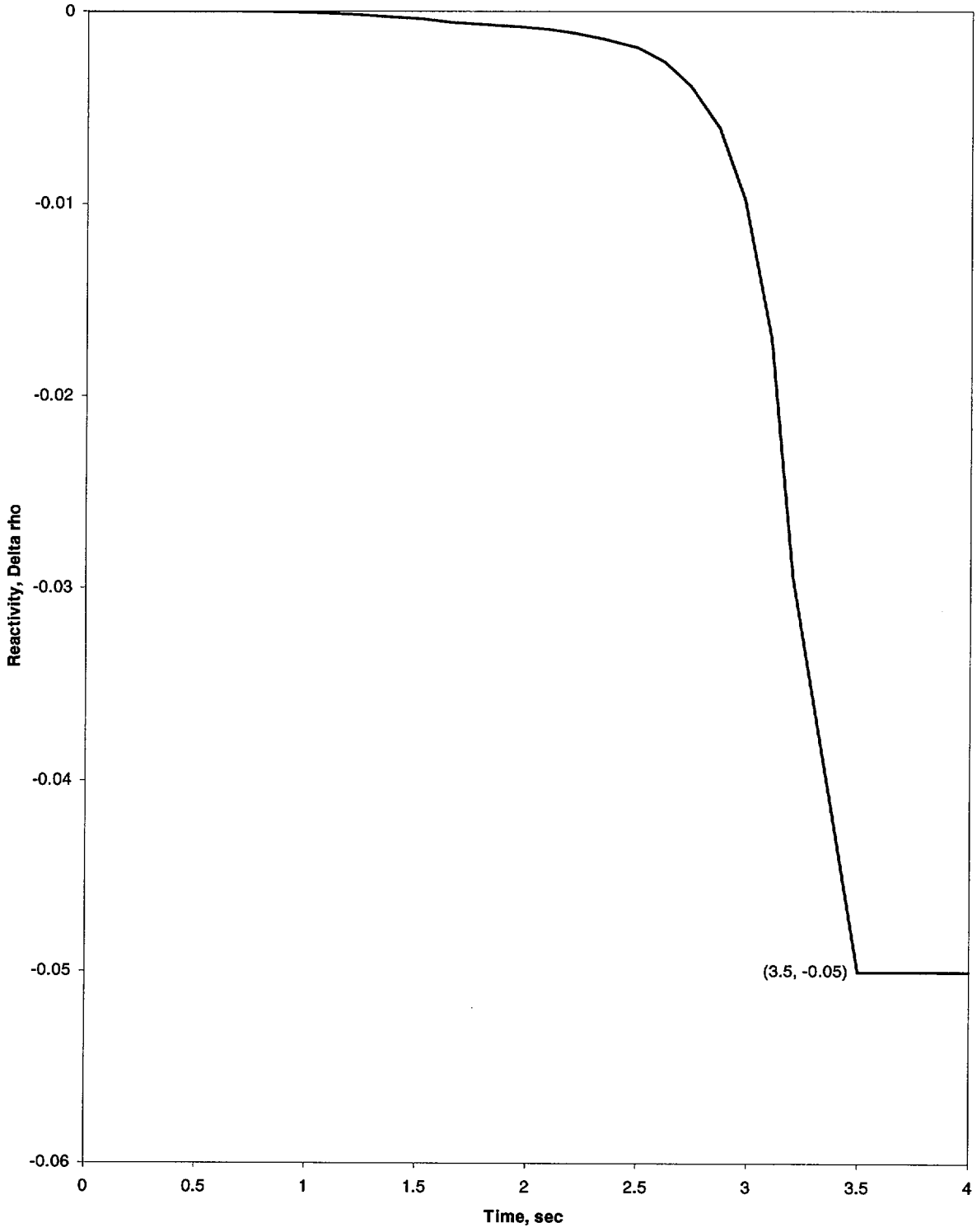


Figure 1.0.2-4

CEA Insertion vs. Time

Figure 1.4.1-1

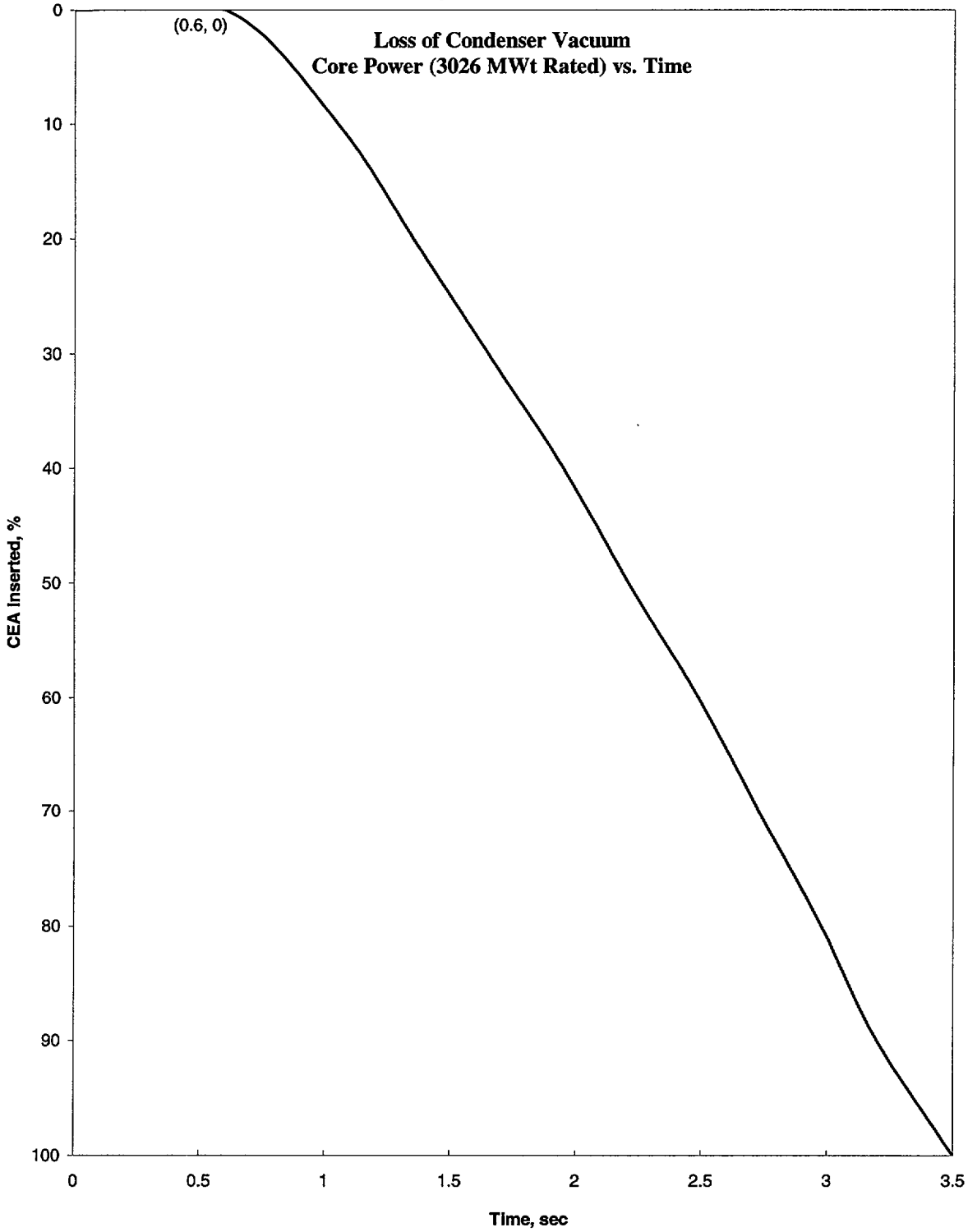


Figure 1.4.1-2

Loss of Condenser Vacuum
Core Average Heat Flux (3026 MWt Rated) vs. Time

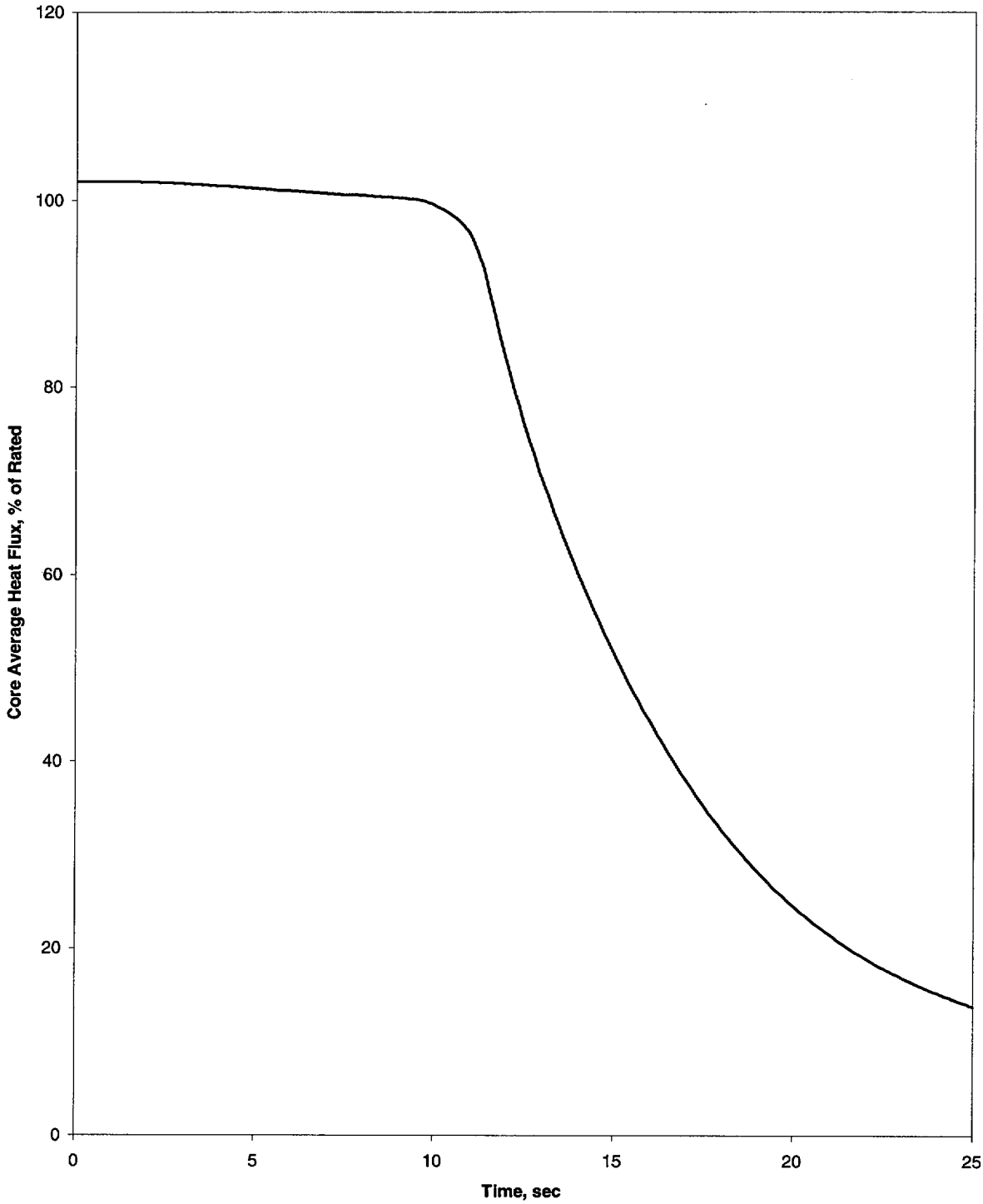


Figure 1.4.1-3

Loss of Condenser Vacuum
Reactor Coolant System Pressure vs. Time

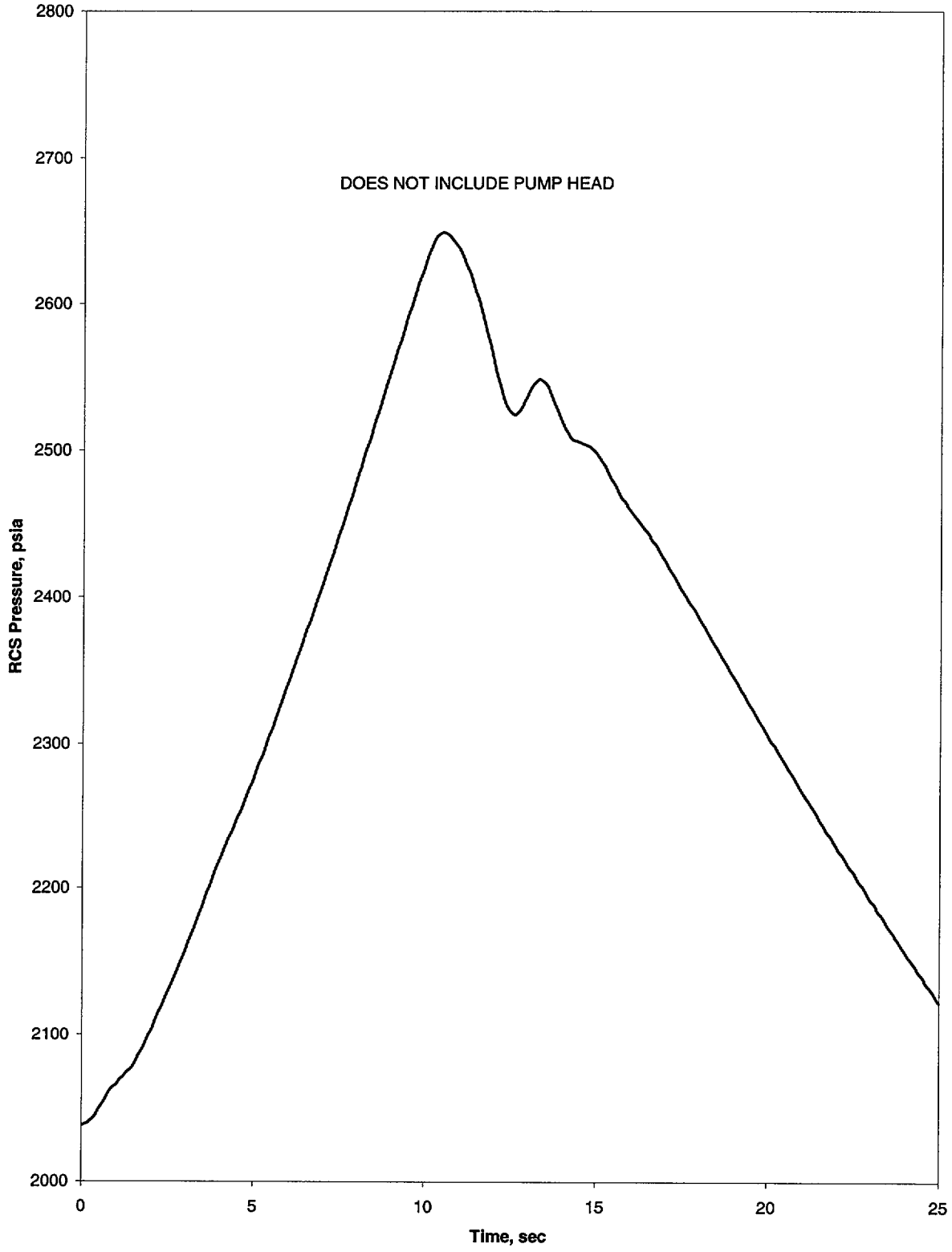


Figure 1.4.1-4

Loss of Condenser Vacuum
Reactor Coolant System Temperature vs. Time

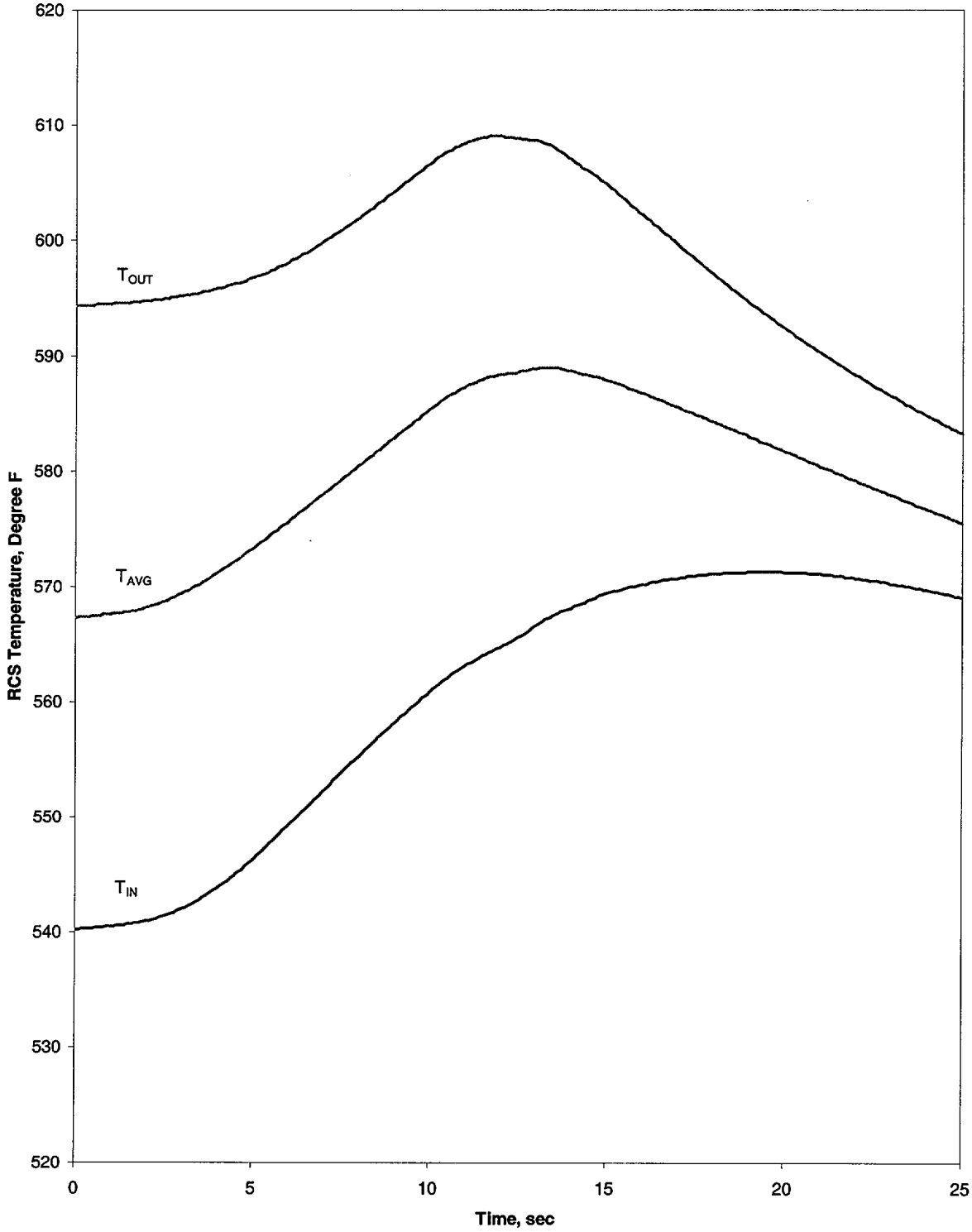


Figure 1.4.1-5

Loss of Condenser Vacuum
Steam Generator Pressure vs. Time

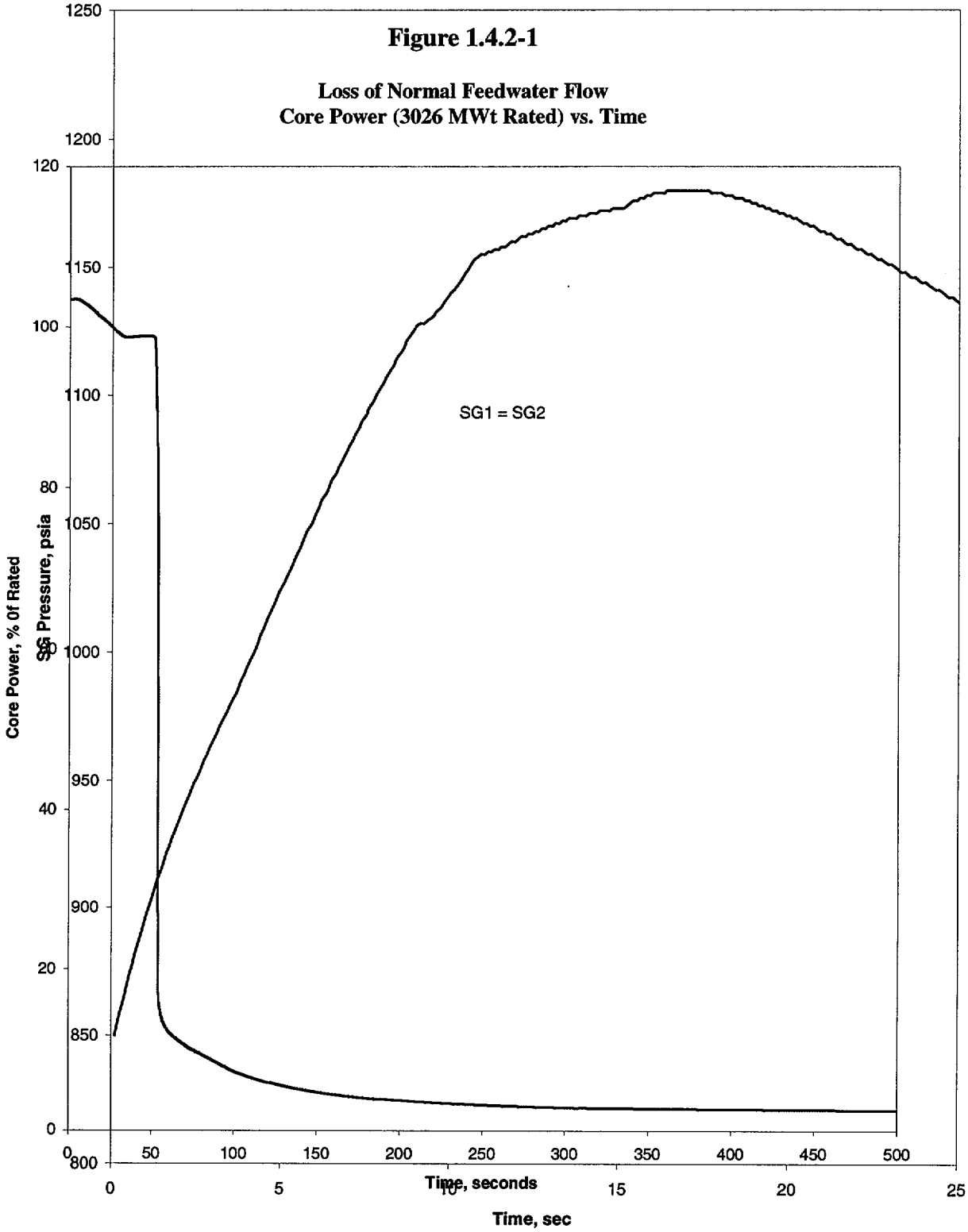


Figure 1.4.2-2

Loss of Normal Feedwater Flow
Core Average Heat Flux (3026 MWt Rated) vs. Time

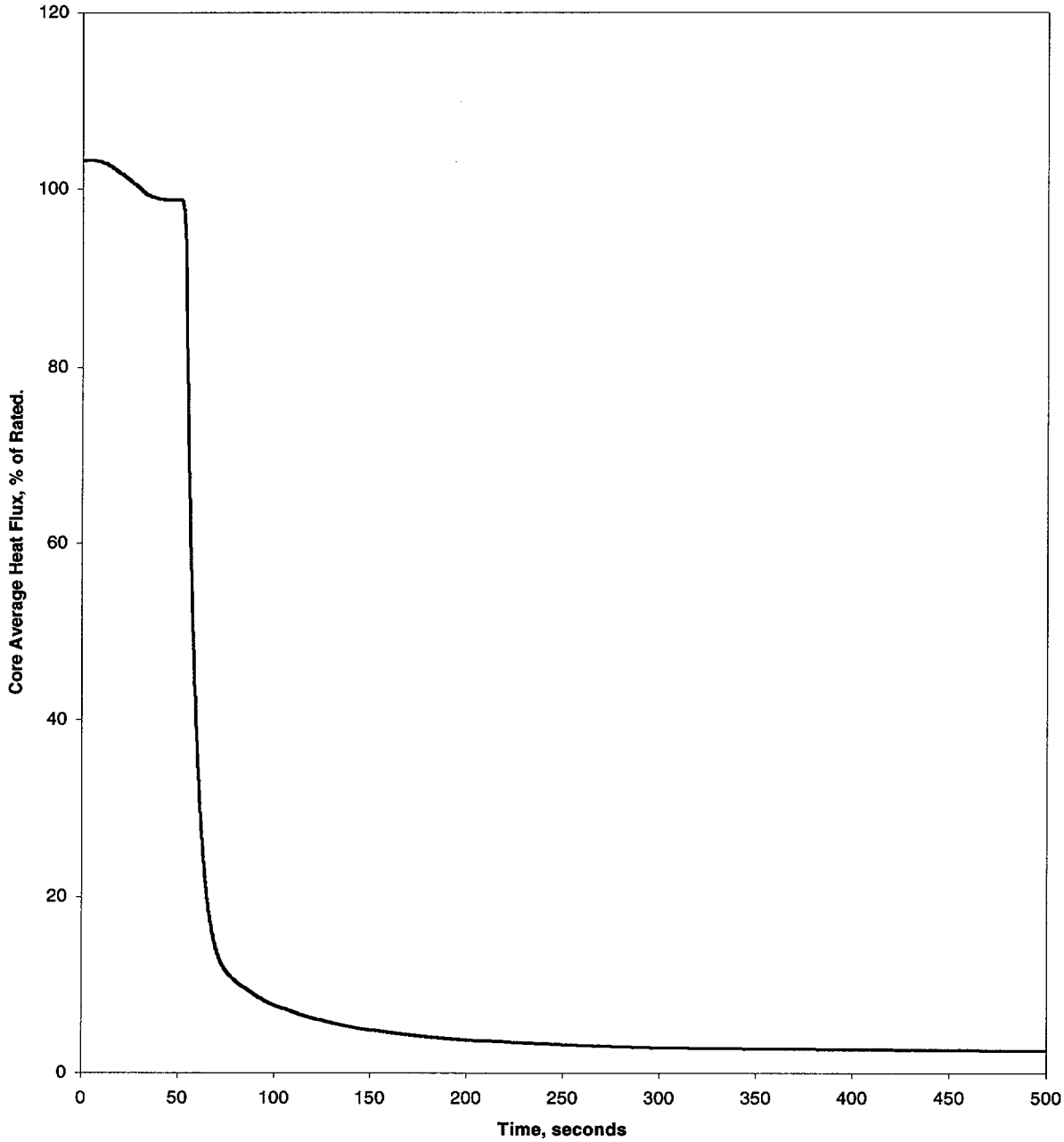


Figure 1.4.2-3

Loss of Normal Feedwater Flow
Reactor Coolant System Pressure vs Time

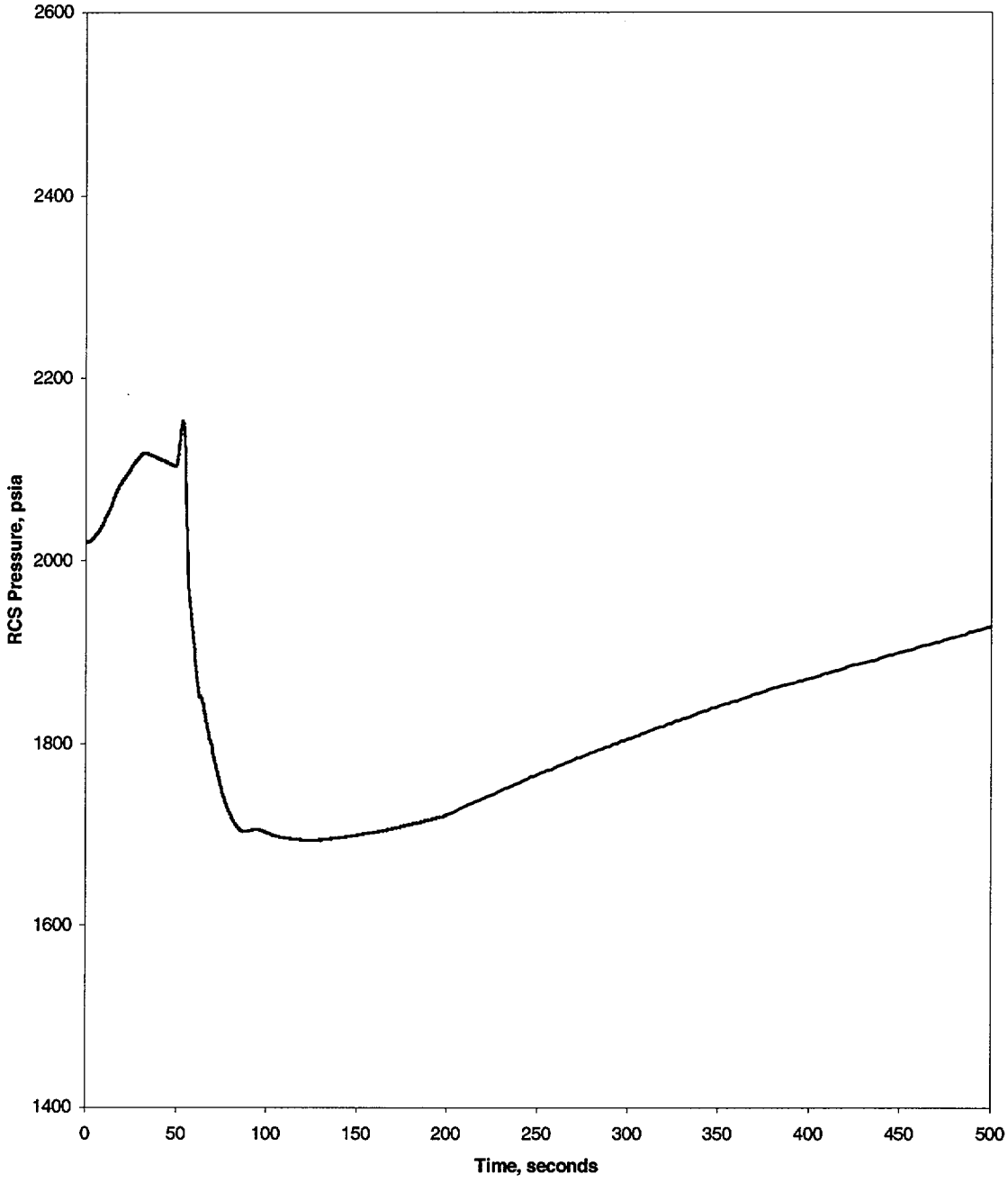


Figure 1.4.2-4

Loss of Normal Feedwater Flow
Reactor Coolant System Temperature vs. Time

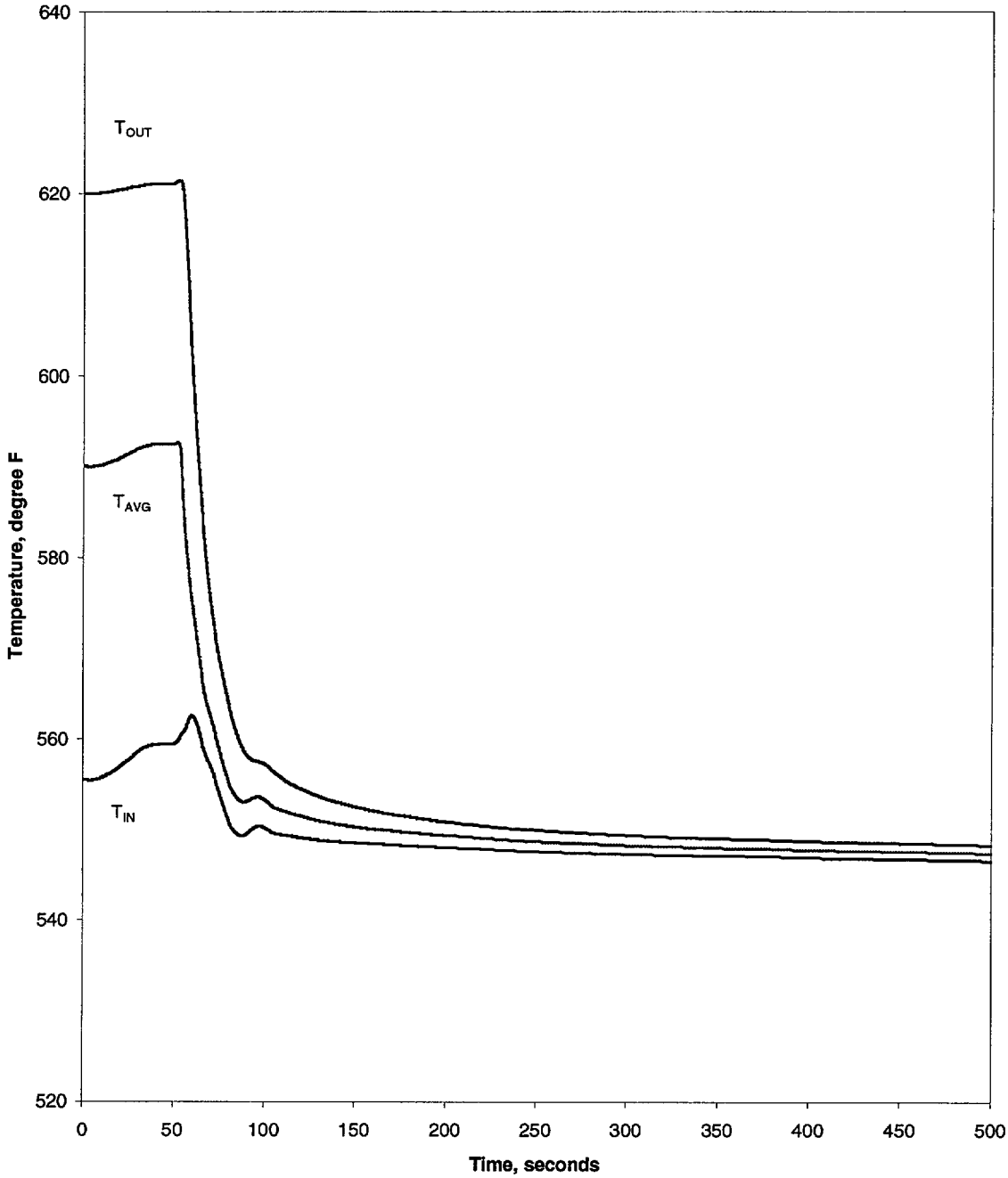


Figure 1.4.2-5

Loss of Normal Feedwater Flow
Steam Generator Pressure vs. Time

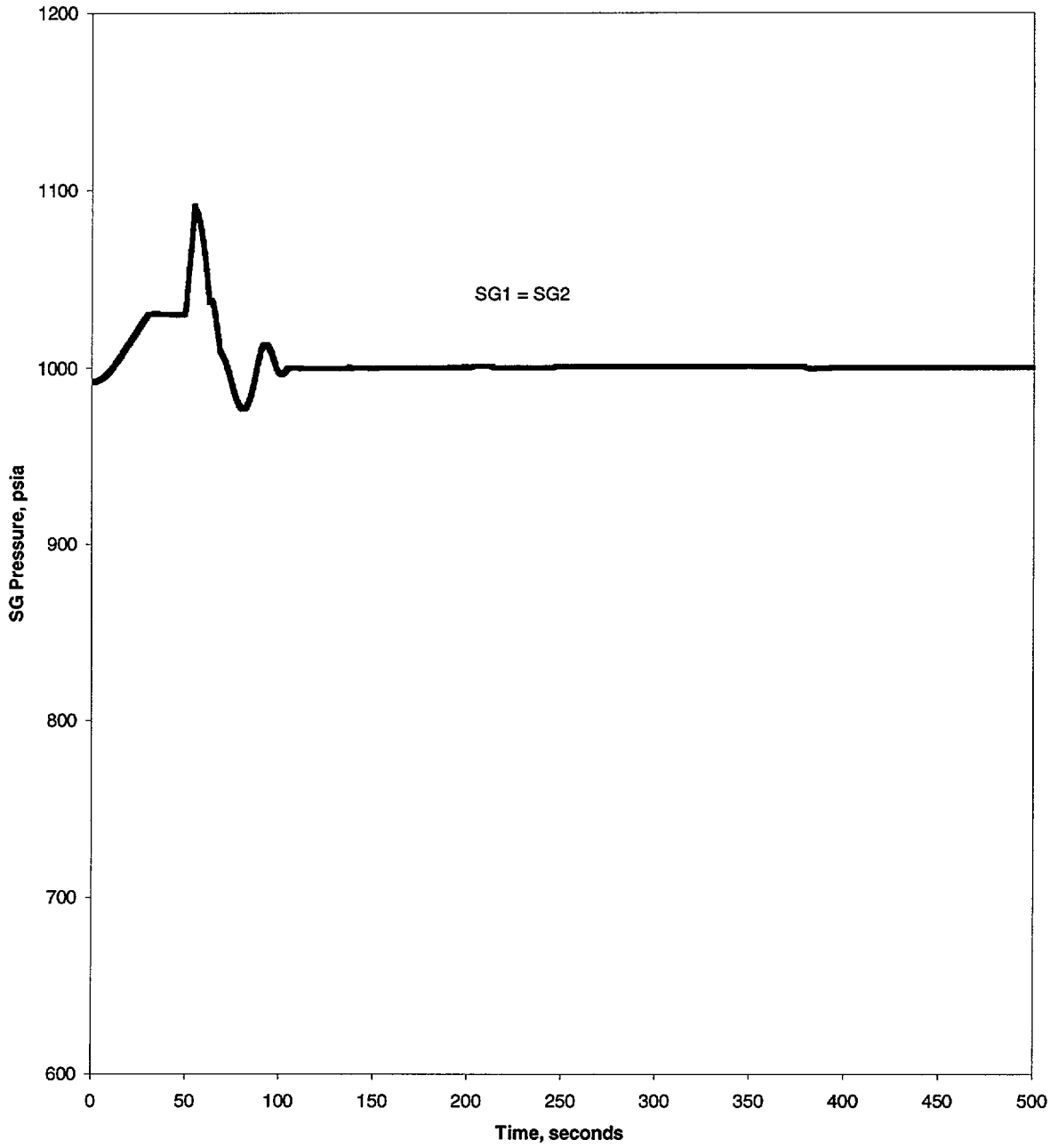


Figure 1.4.4-1

Feedwater Line Break
Core Power (2815 MWt Rated) vs. Time

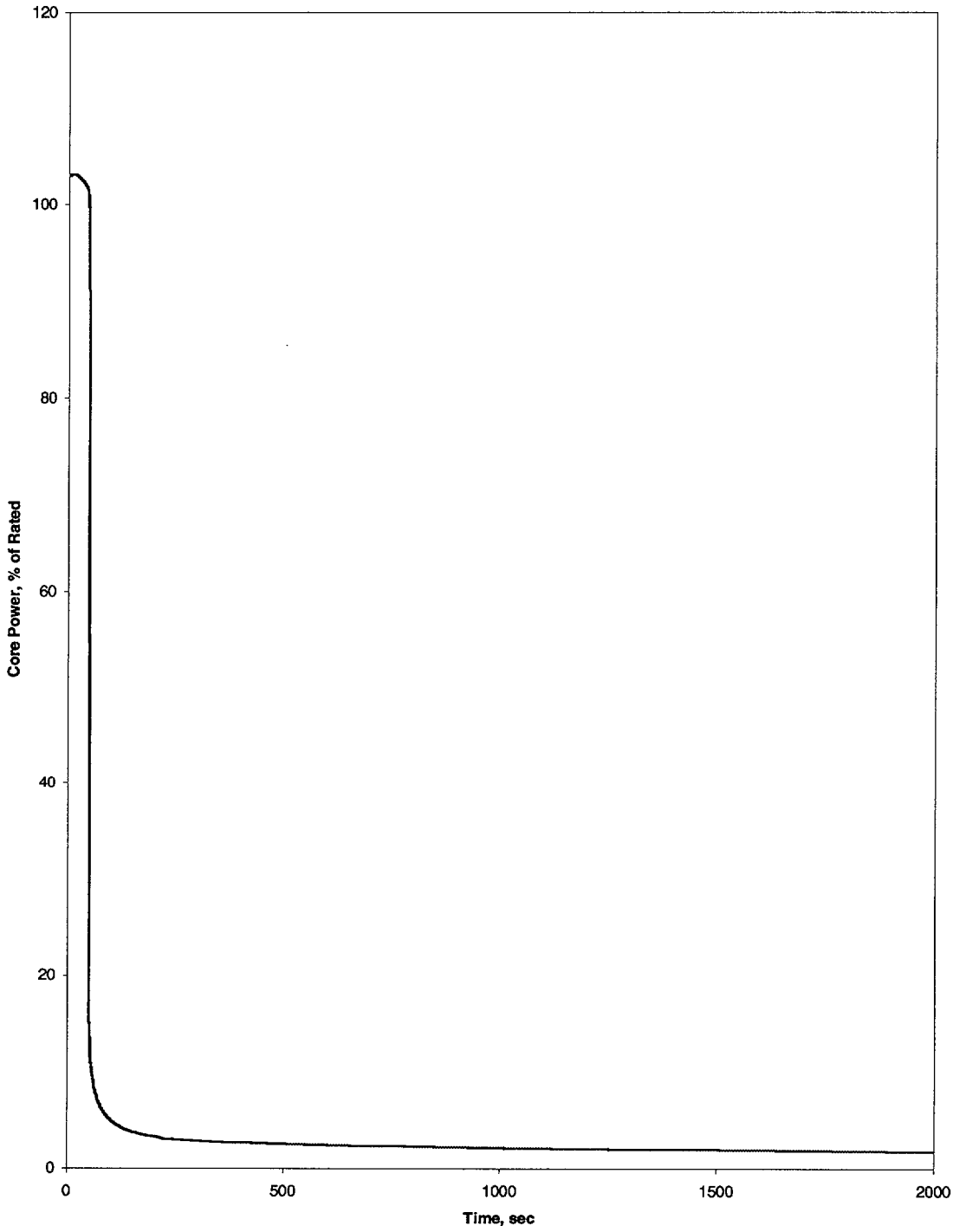


Figure 1.4.4-2

Feedwater Line Break
Core Average Heat Flux (2815 MWt Rated) vs. Time

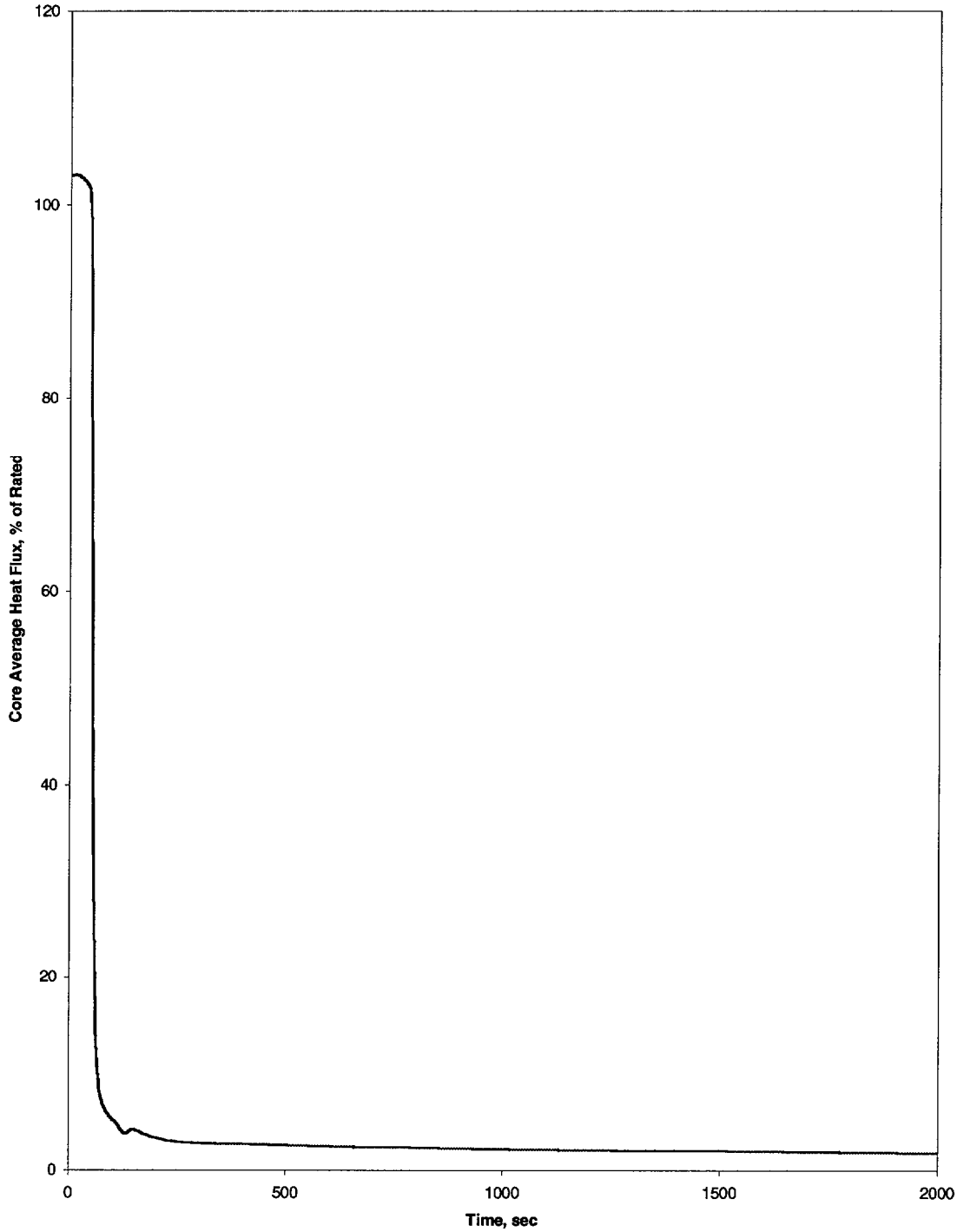


Figure 1.4.4-3

Feedwater Line Break
Reactor Coolant System Pressure vs. Time

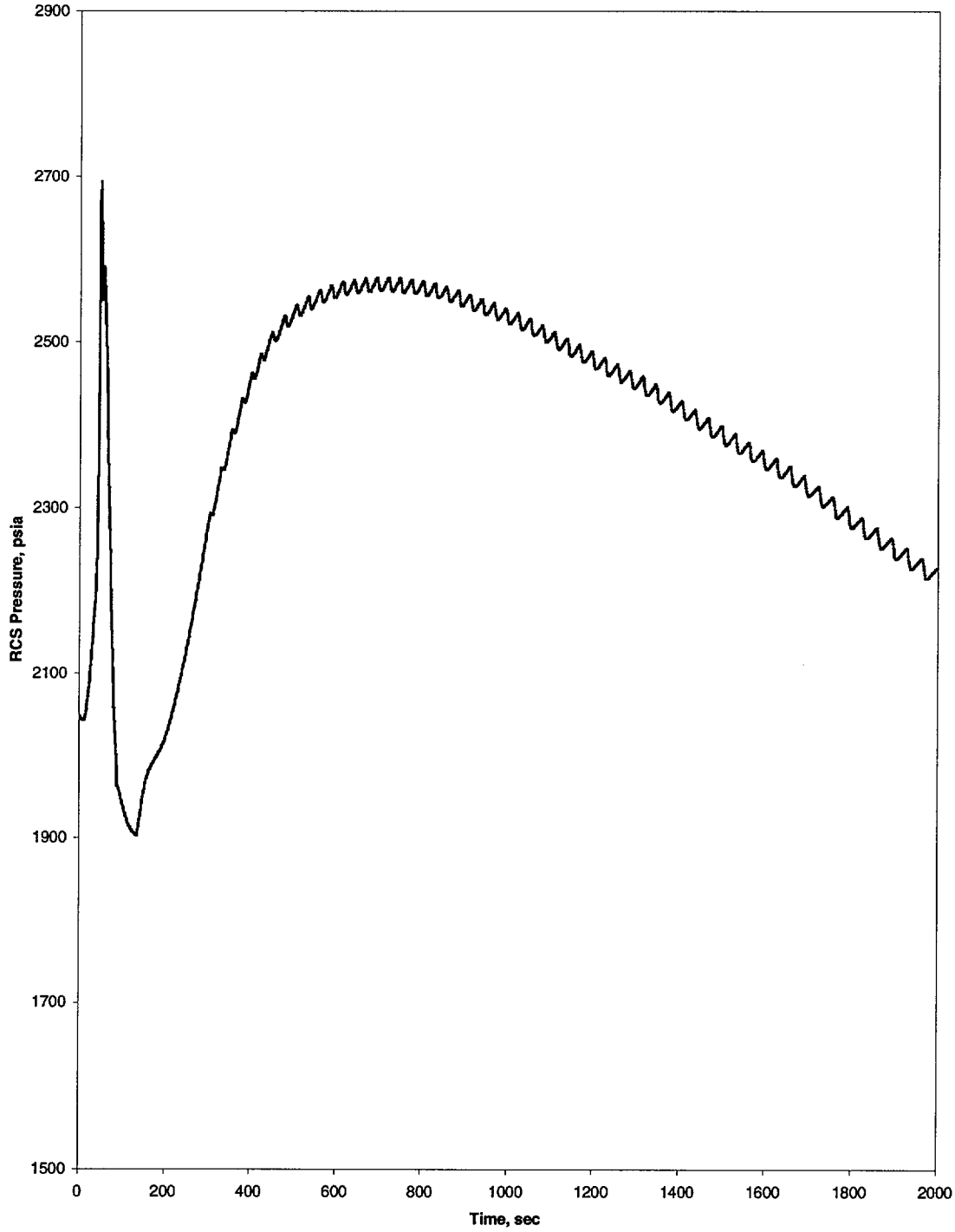


Figure 1.4.4-4

Feedwater Line Break
Reactor Coolant System Temperature vs. Time

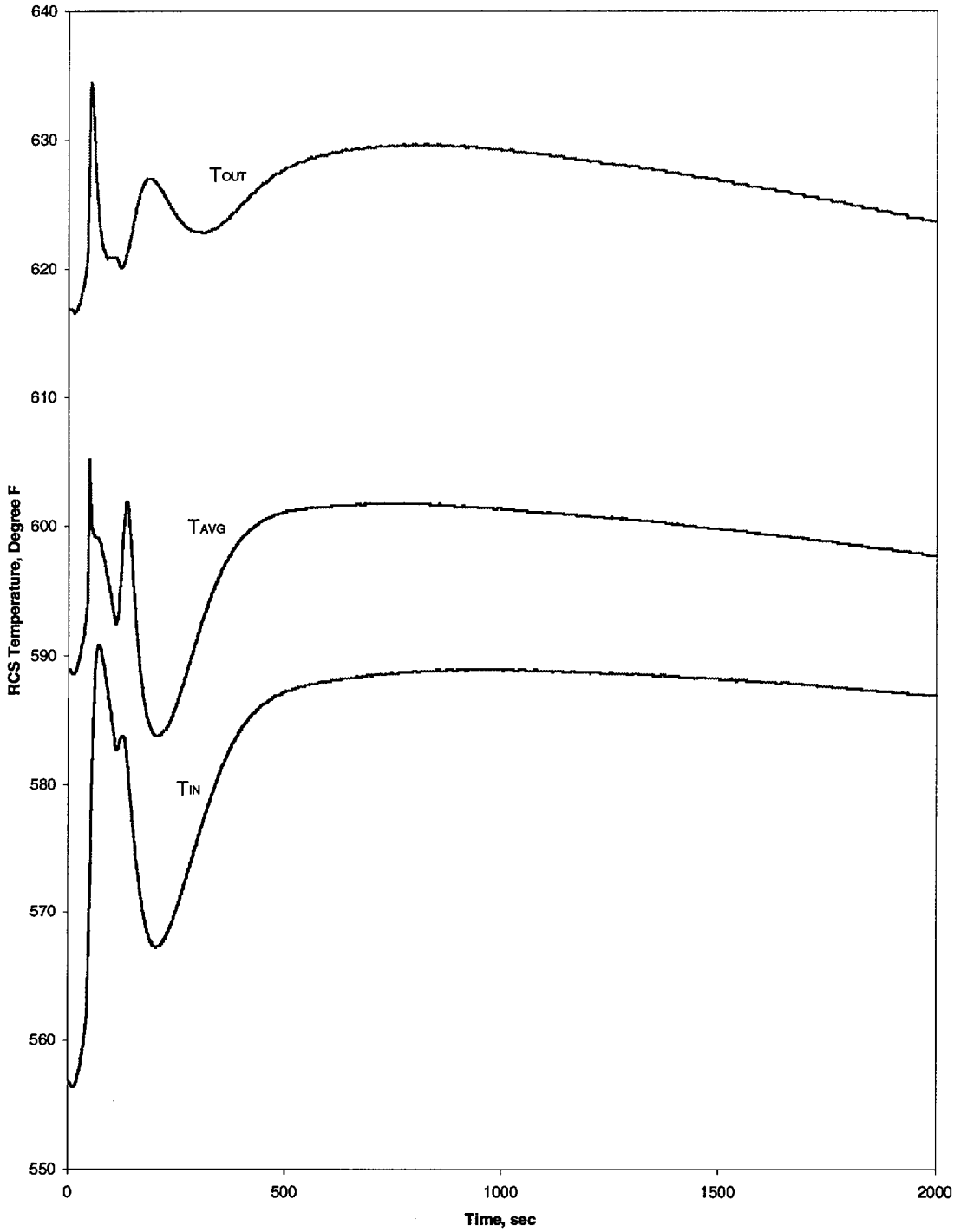


Figure 1.4.4-5

Feedwater Line Break
Steam Generator Pressure vs. Time

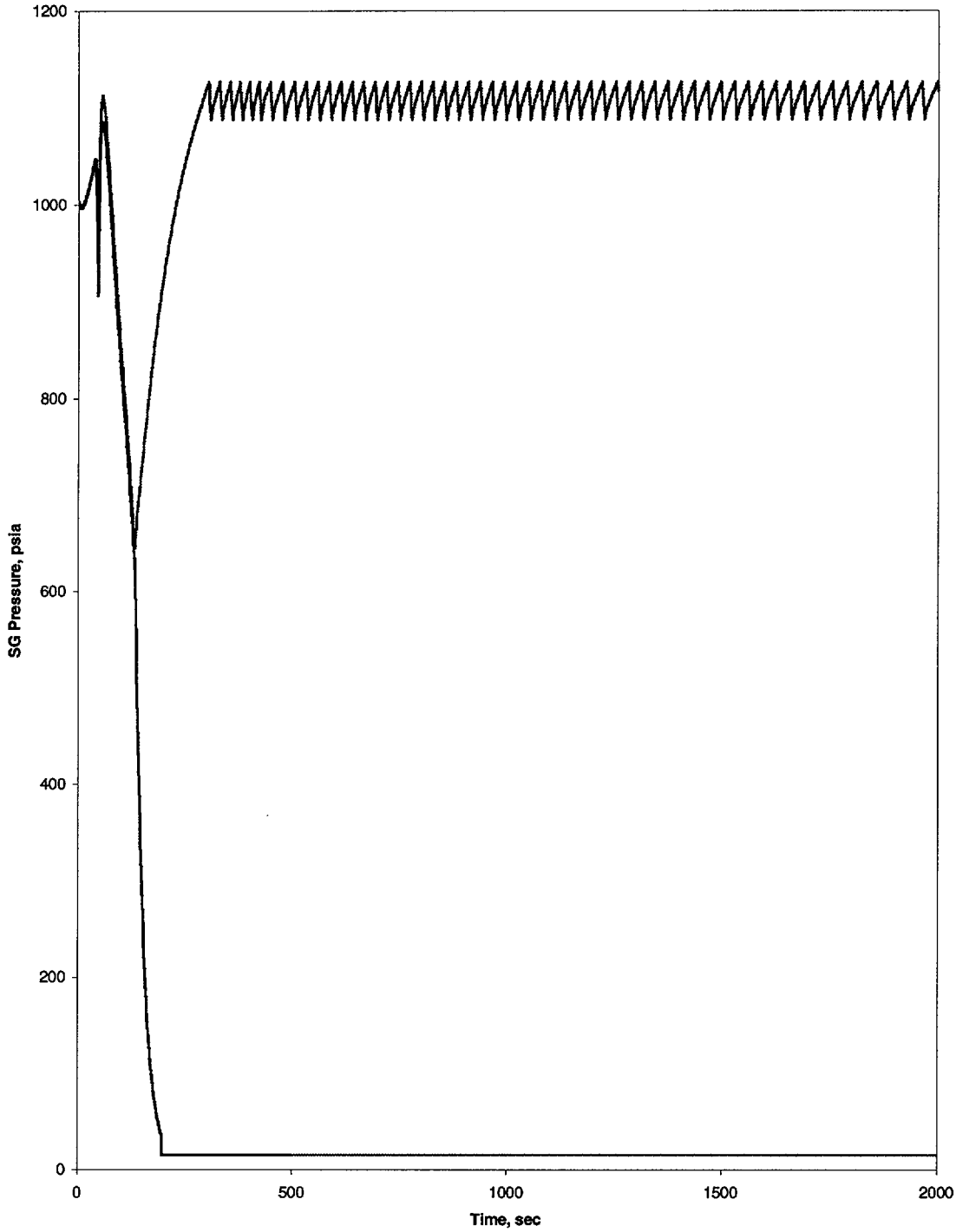


Figure 1.5.1-1

Feedwater System Malfunction
Core Power (3026 MWt Rated) vs. Time

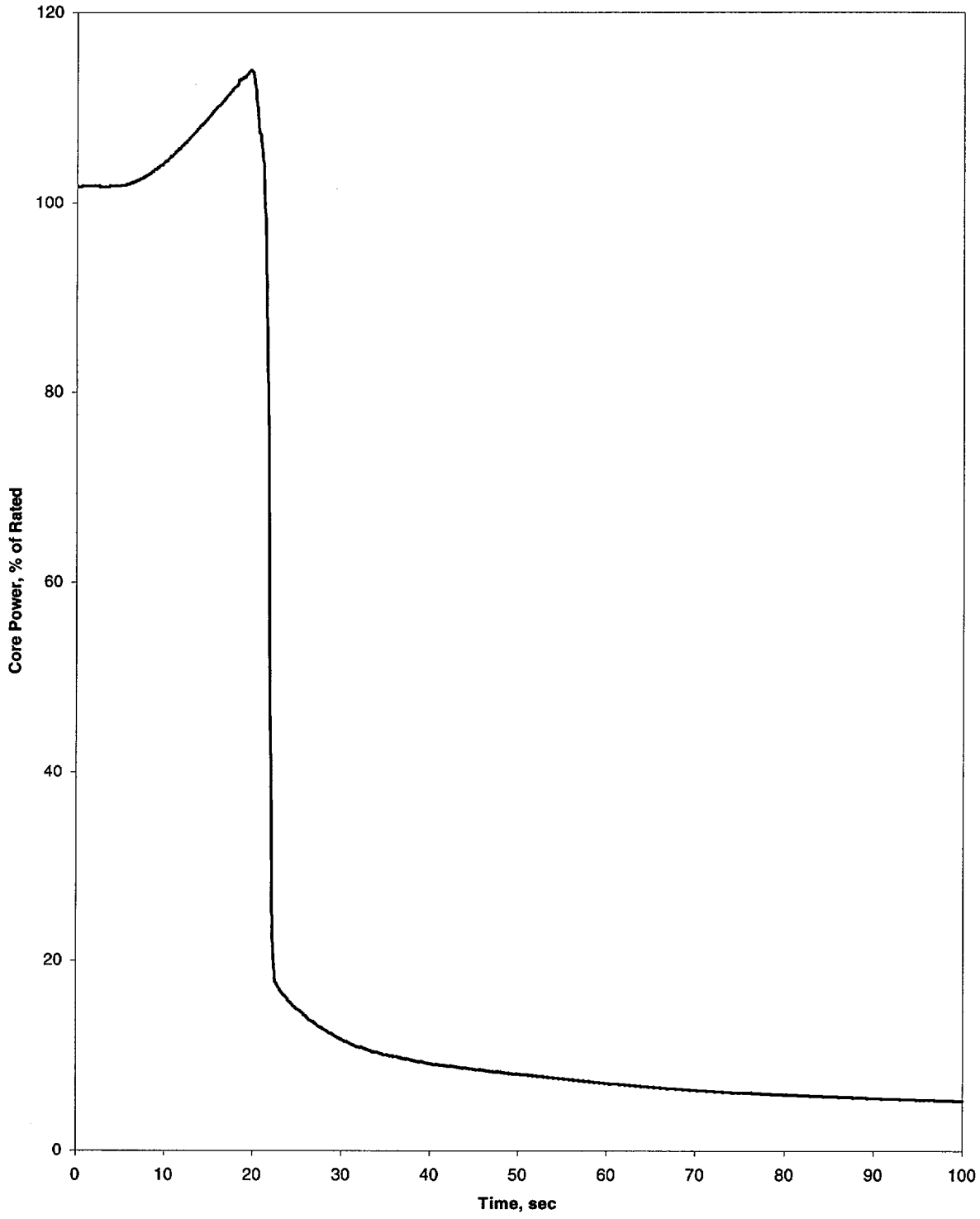


Figure 1.5.1-2

Feedwater System Malfunction
Core Average Heat Flux (3026 MWt Rated) vs. Time

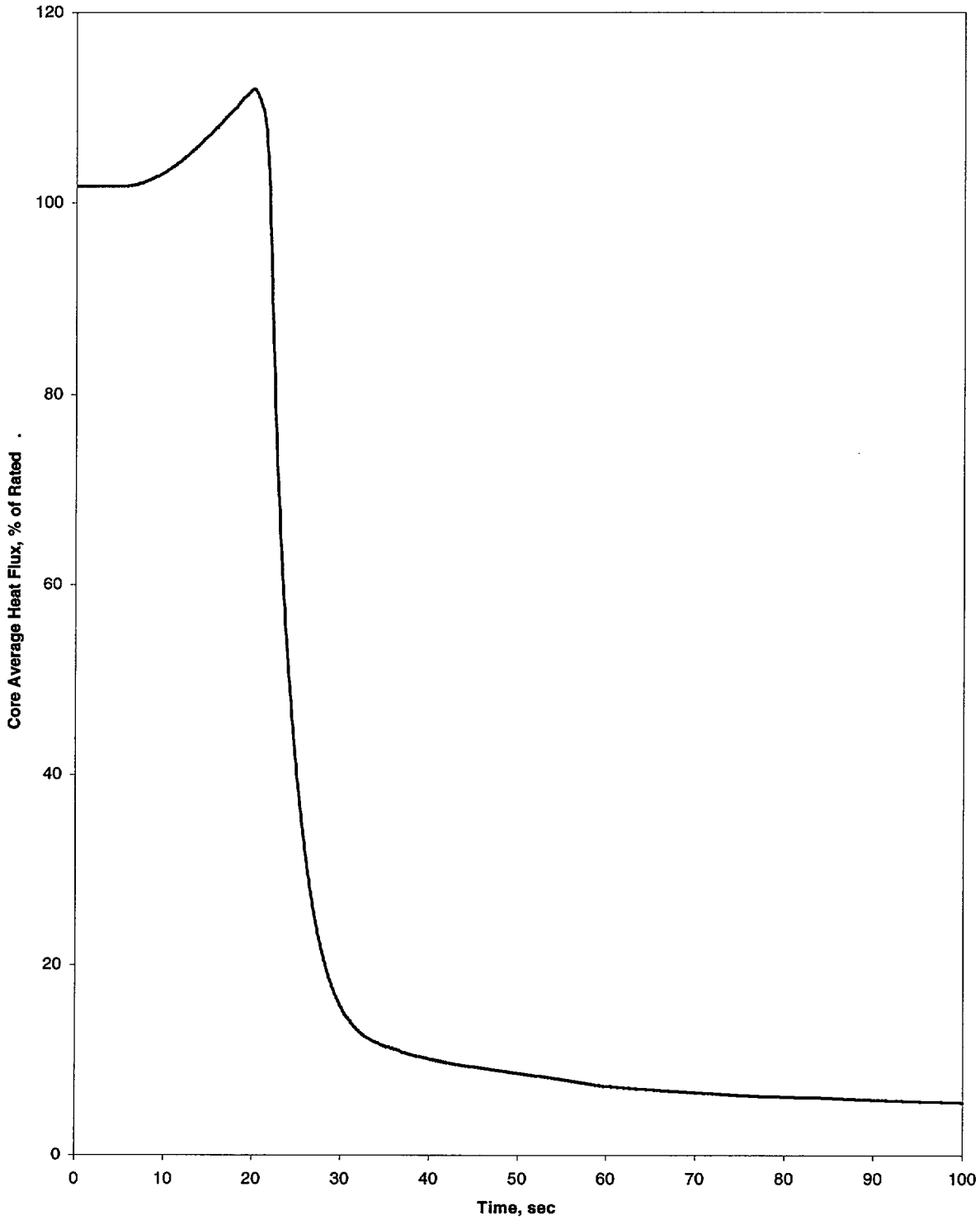


Figure 1.5.1-3

Feedwater System Malfunction
Reactor Coolant System Pressure vs. Time

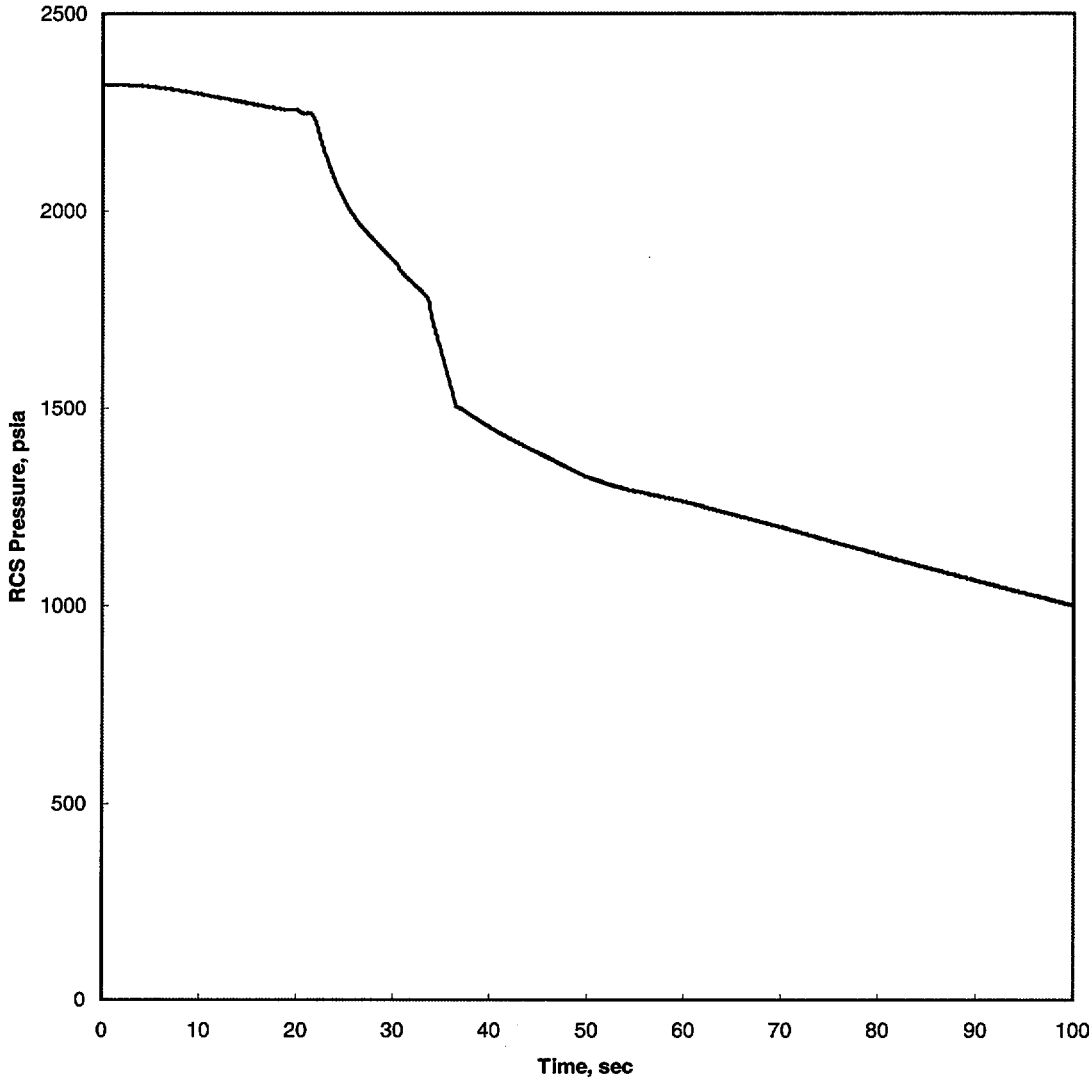


Figure 1.5.1-4

Feedwater System Malfunction
Reactor Coolant System Temperature vs. Time

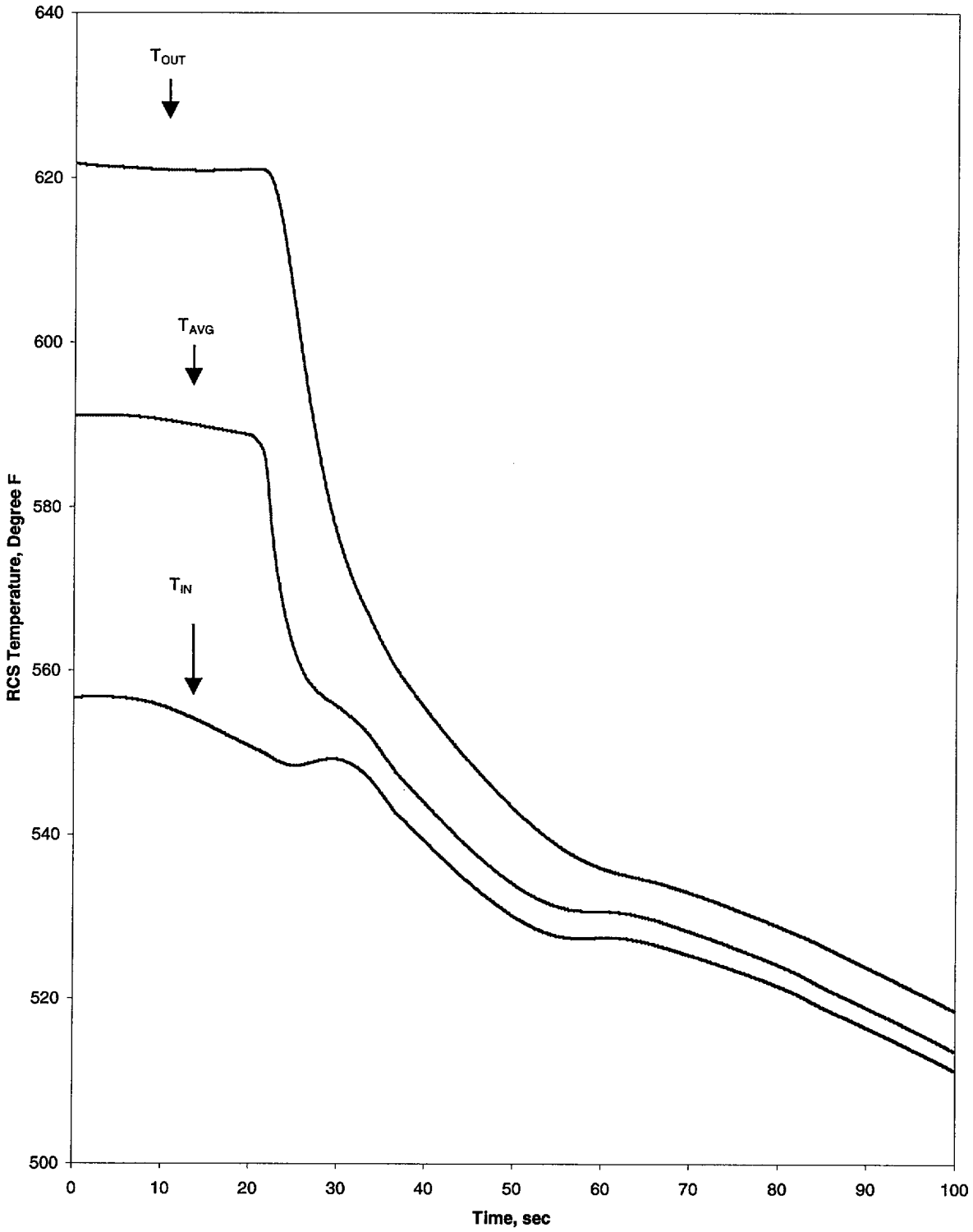


Figure 1.5.1-5

Feedwater System Malfunction
Steam Generator Pressure vs. Time

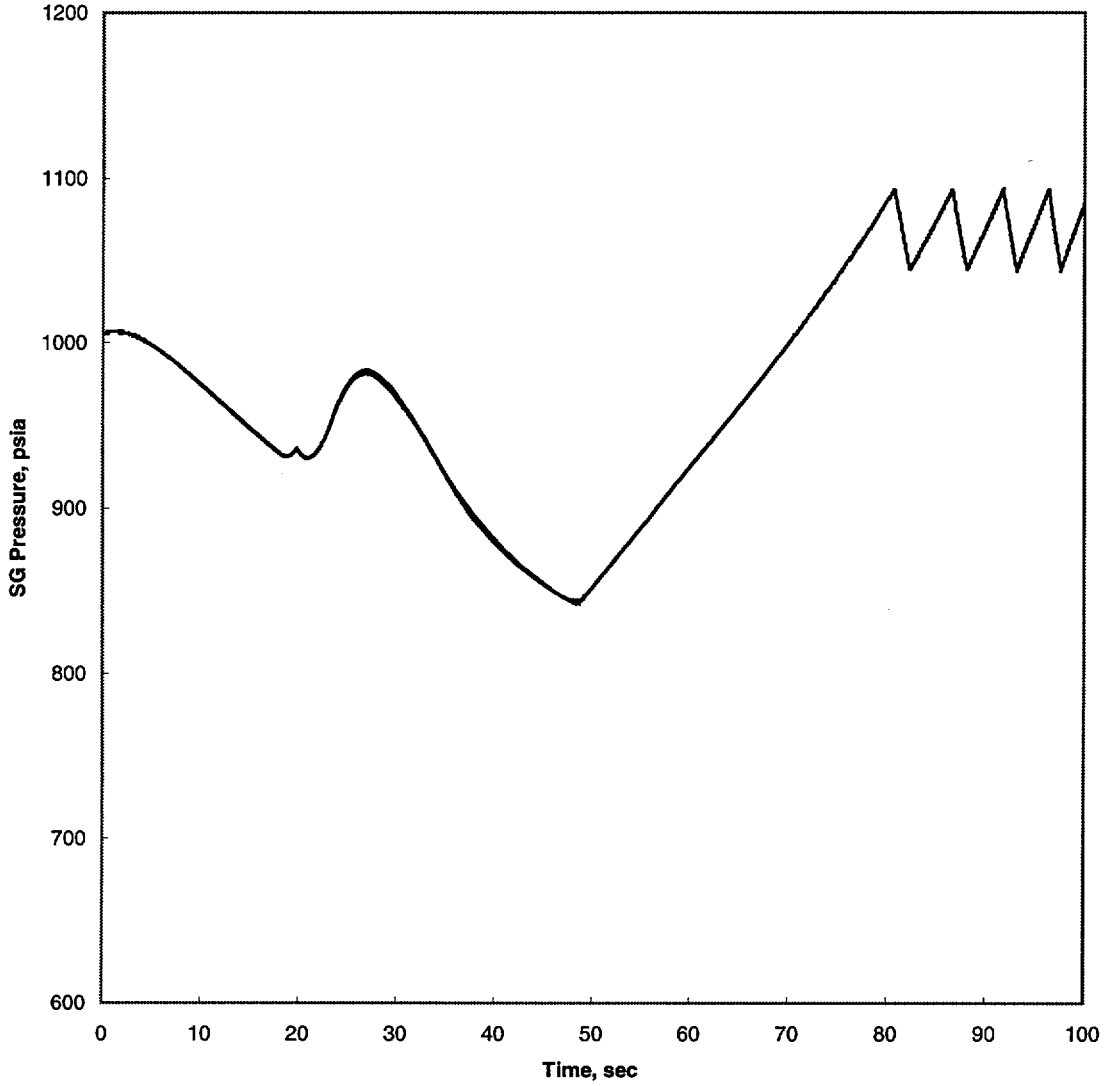


Figure 1.5.2-1

Steam Bypass System Malfunction
Core Power (3026 MWt Rated) vs. Time

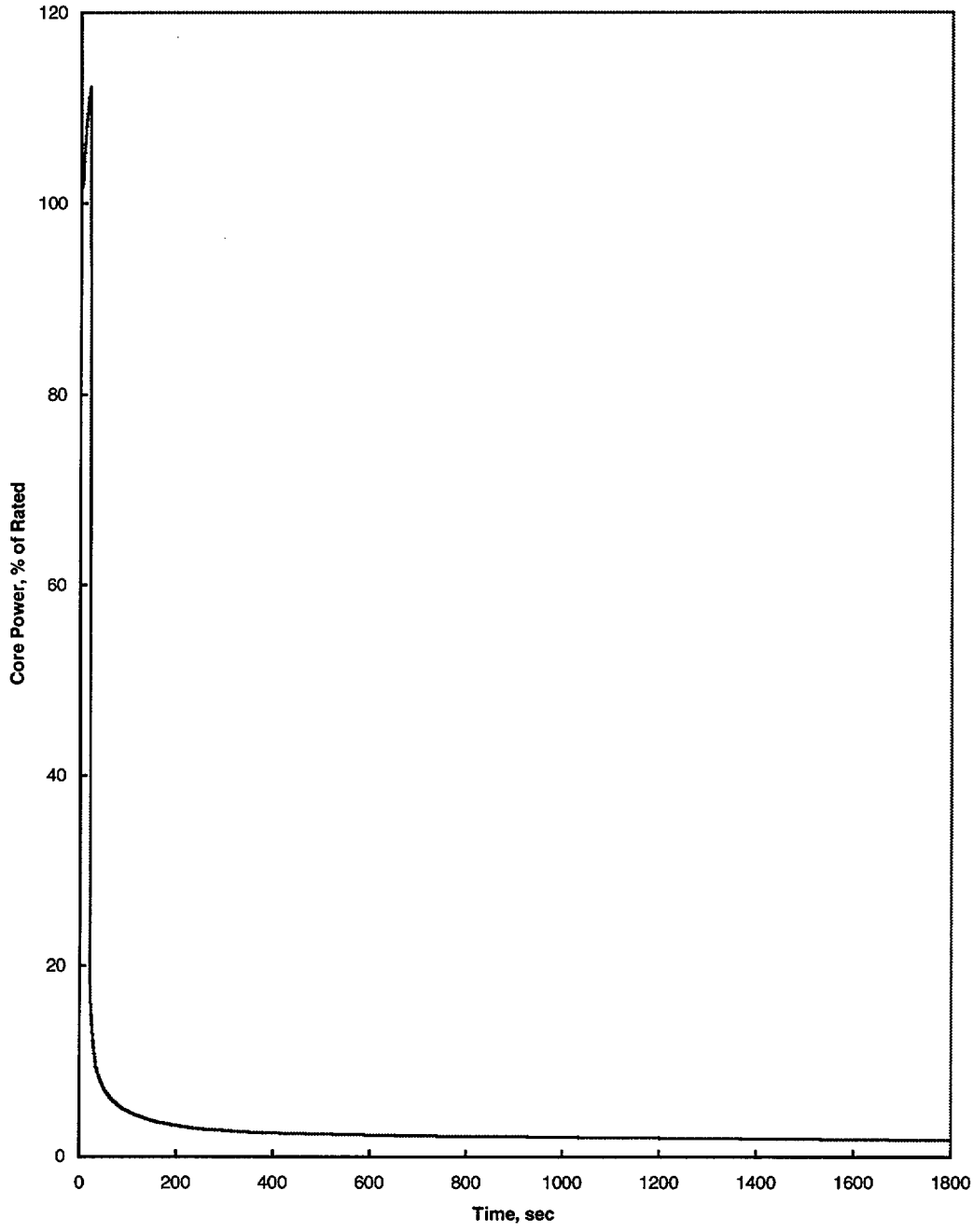


Figure 1.5.2-2

Steam Bypass System Malfunction
Core Average Heat Flux (3026 MWt Rated) vs. Time

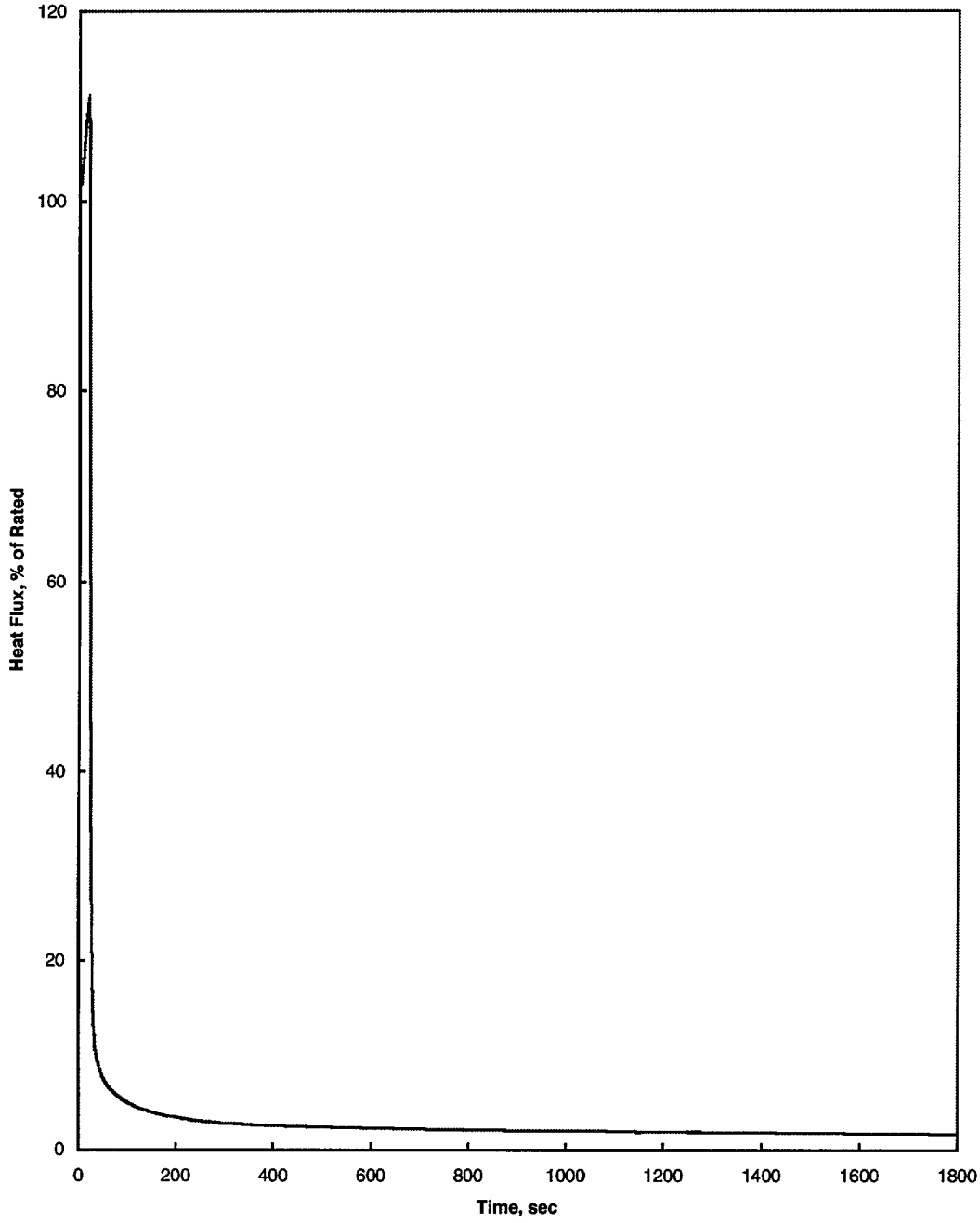


Figure 1.5.2-3

Steam Bypass System Malfunction
Reactor Coolant System Pressure vs. Time

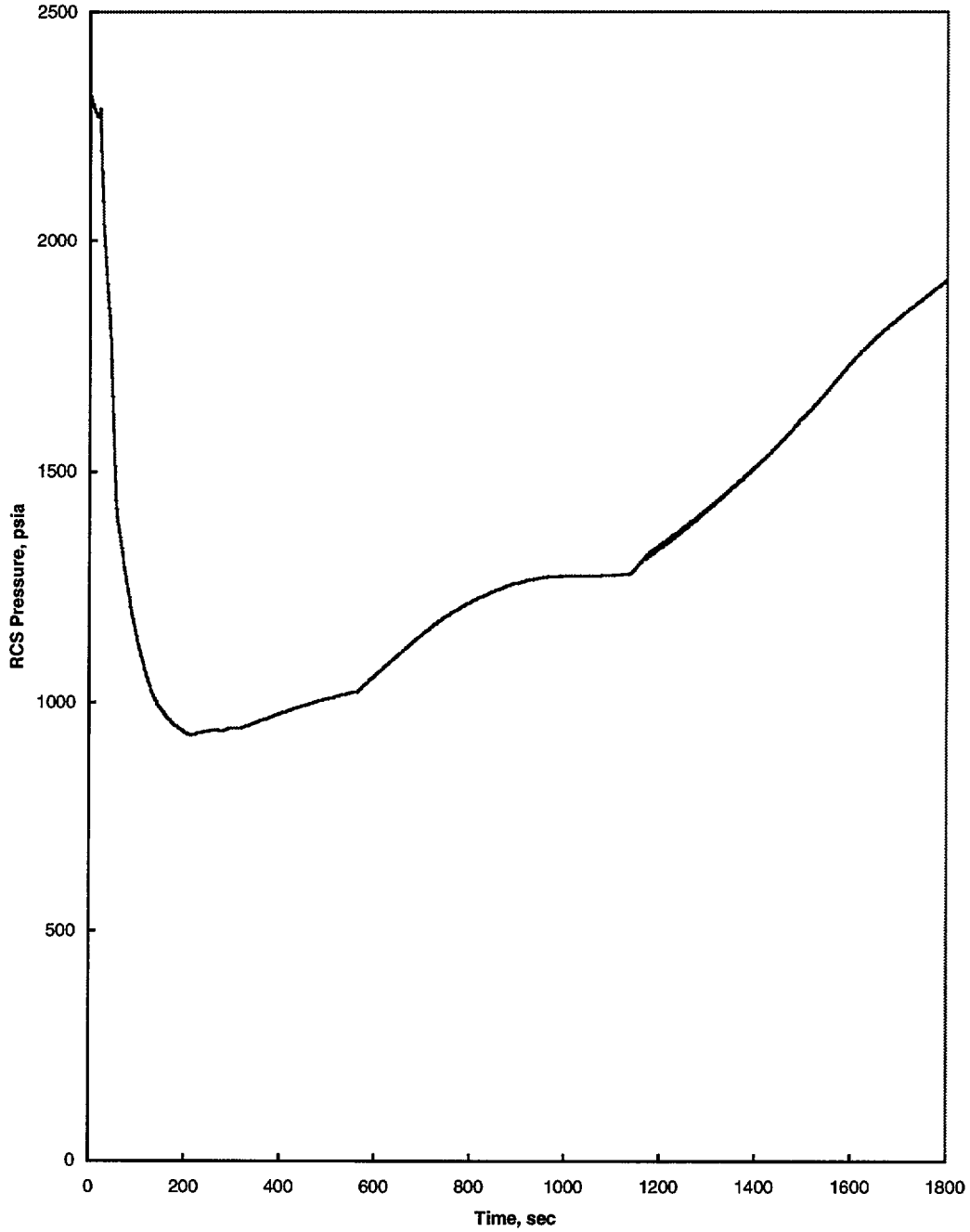


Figure 1.5.2-4

Steam Bypass System Malfunction
Reactor Coolant System Temperature vs. Time

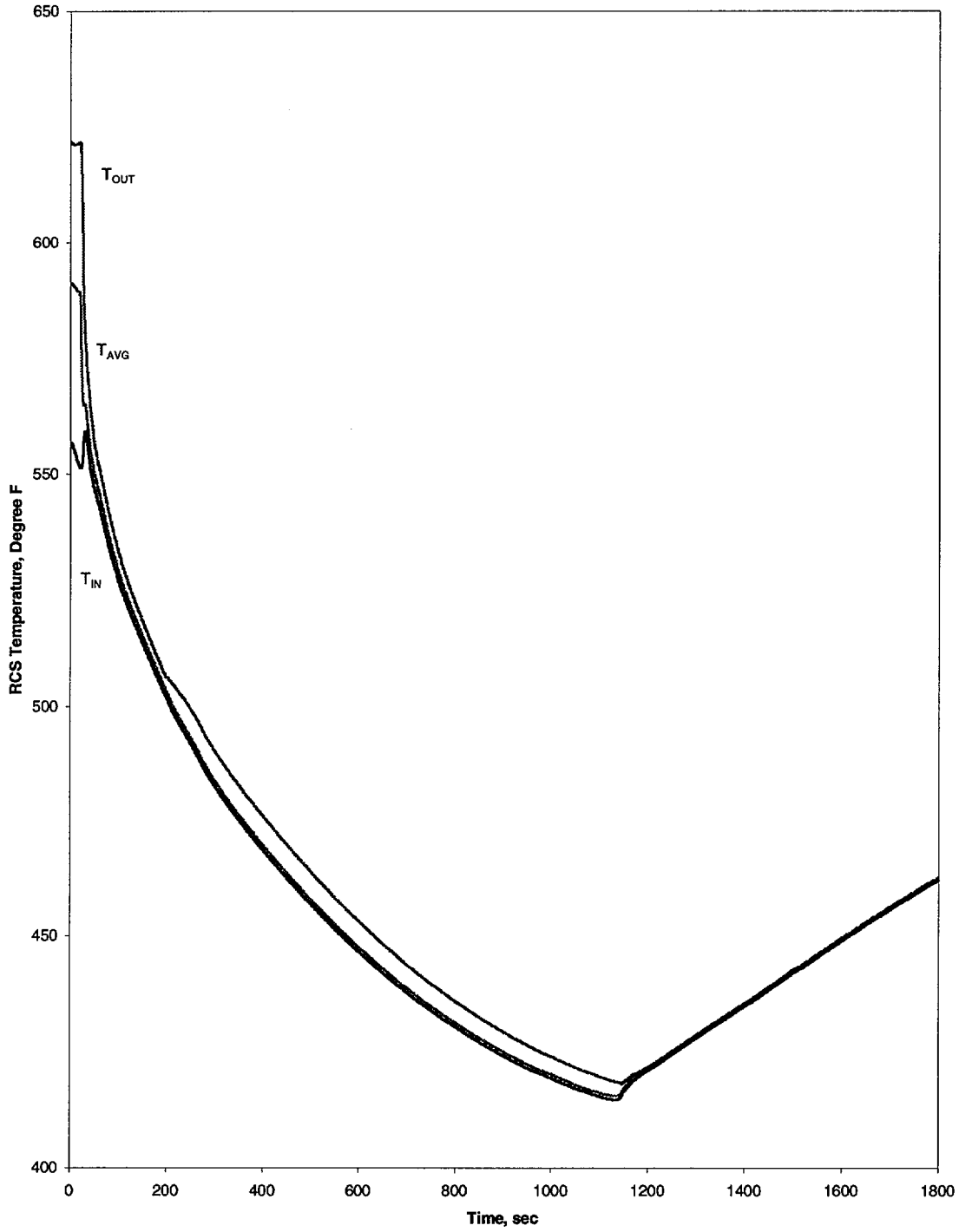


Figure 1.5.2-5

Steam Bypass System Malfunction
Steam Generator Pressure vs. Time

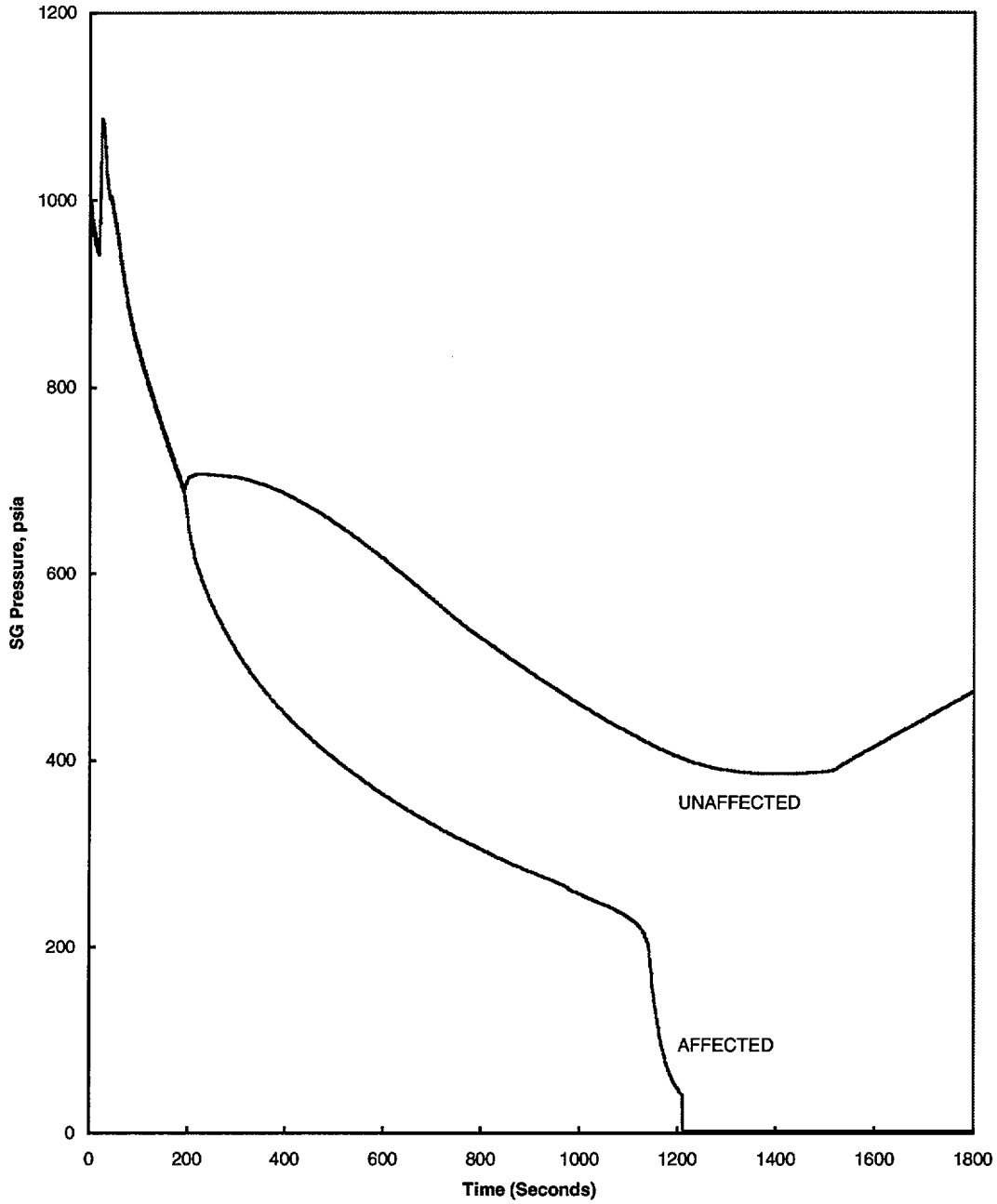


Figure 1.5.3-1

Replacement Steam Generator and Power Uprate Moderator Cooldown Curves
Moderator Reactivity vs. Moderator Temperature

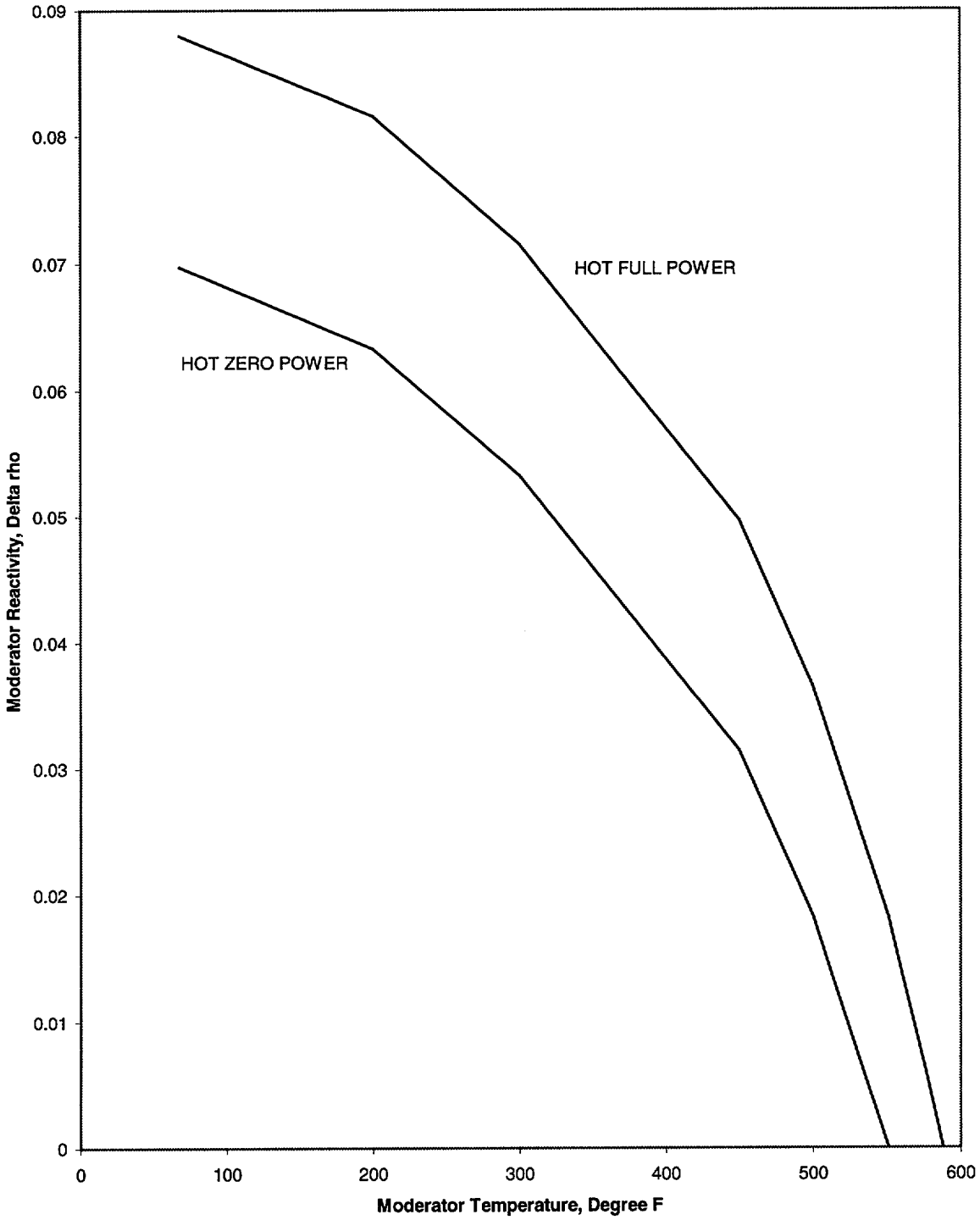


Figure 1.5.3-2

Hot Full Power with Loss of AC, Inside Containment Break
Core Power (3026 MWt Rated) vs. Time

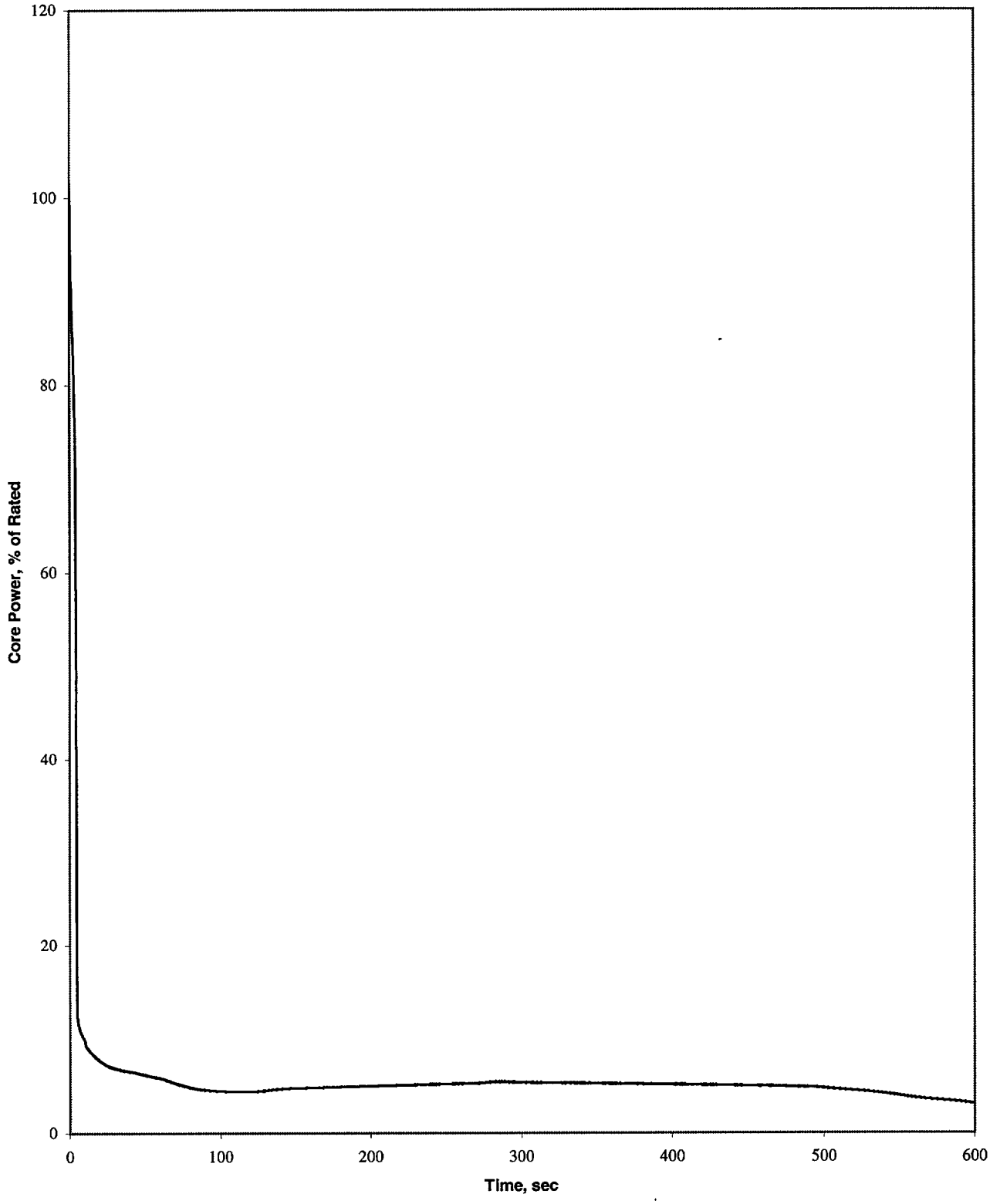


Figure 1.5.3-3

Hot Full Power with Loss of AC, Inside Containment Break
Core Average Heat Flux (3026 MWt Rated) vs. Time

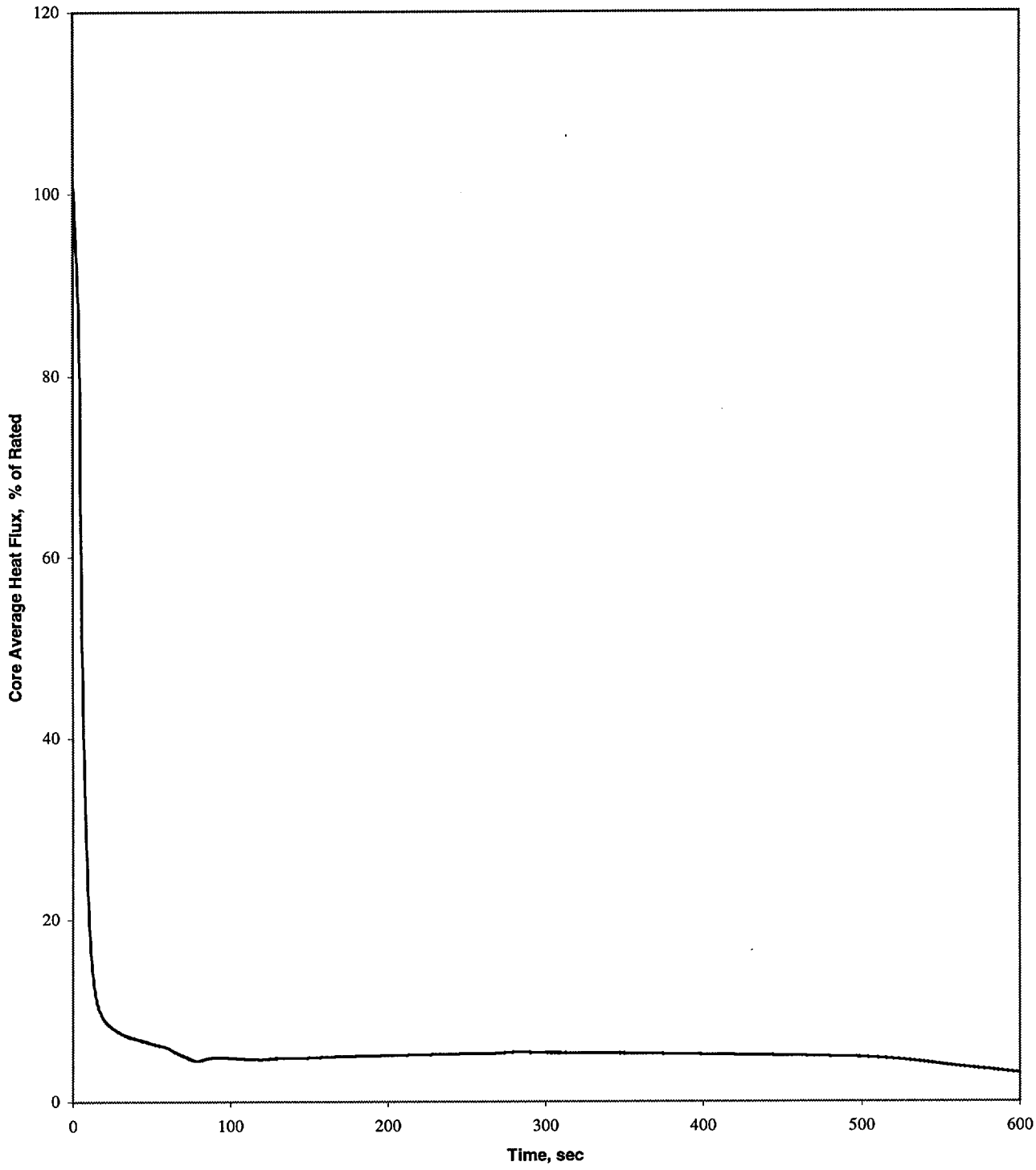


Figure 1.5.3-4

Hot Full Power with Loss of AC, Inside Containment Break
Reactor Coolant System Pressure vs. Time

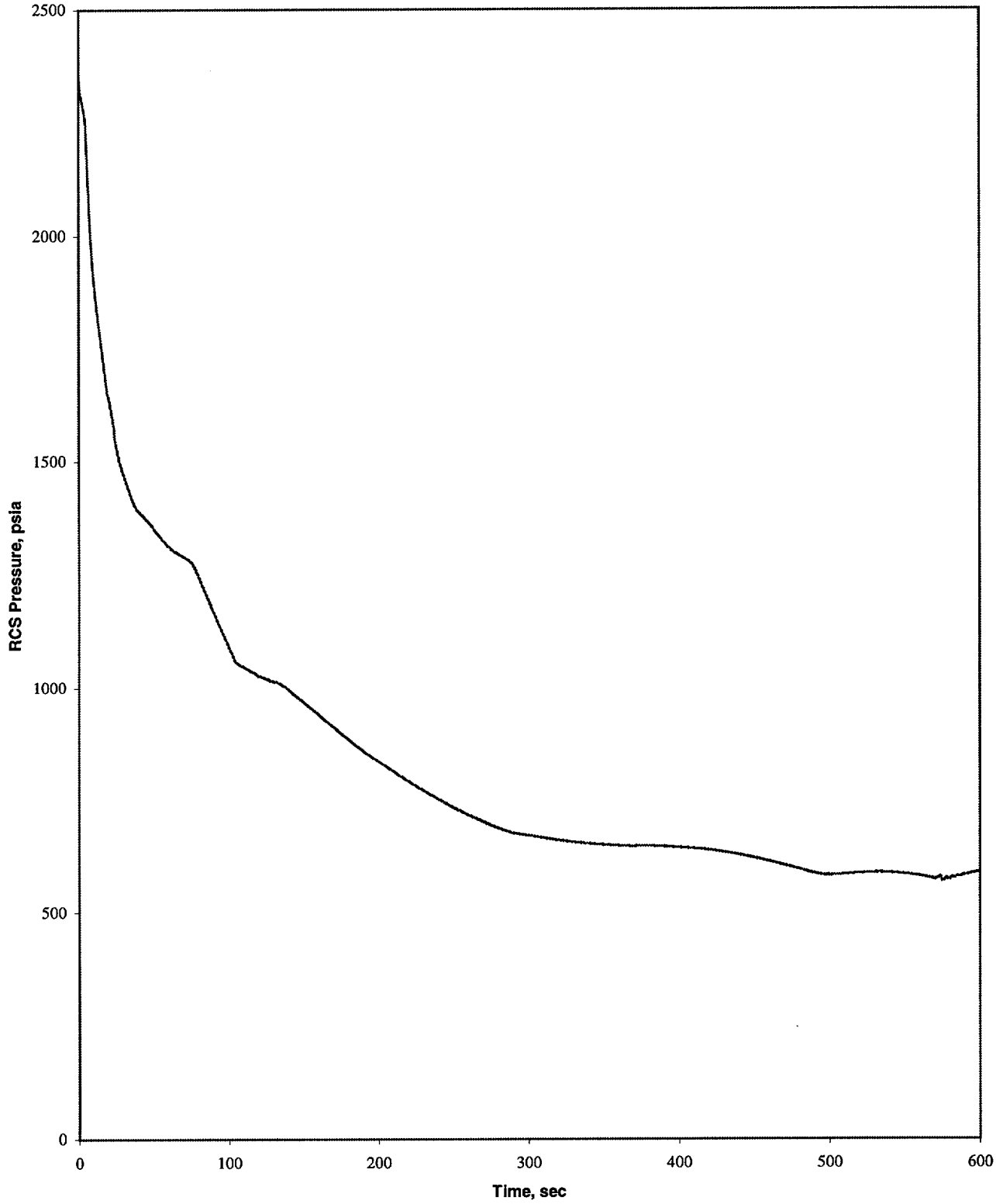


Figure 1.5.3-5

Hot Full Power with Loss of AC, Inside Containment Break
Reactor Coolant System Temperature vs. Time

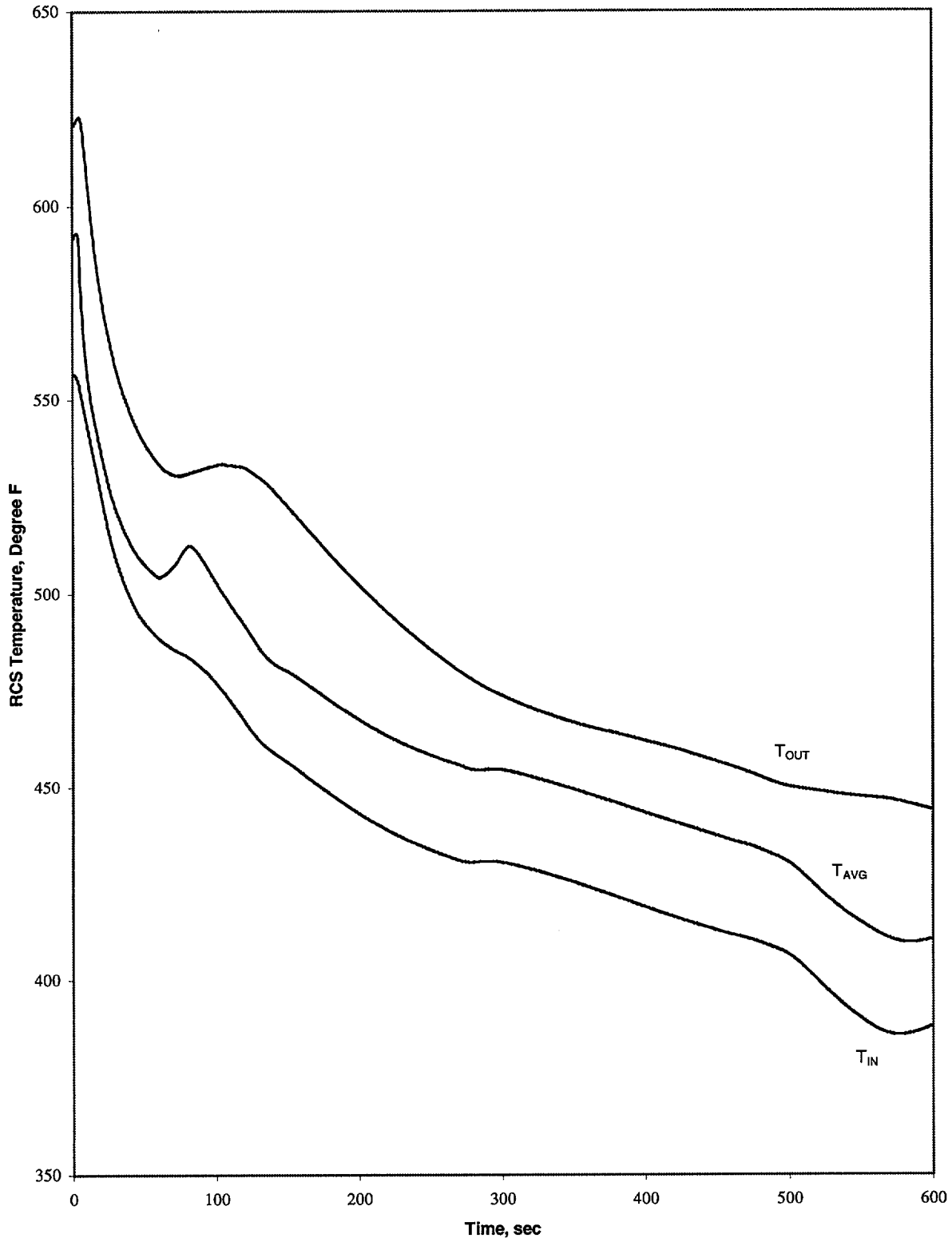


Figure 1.5.3-6

Hot Full Power with Loss of AC, Inside Containment Break
Steam Generator Pressure vs. Time

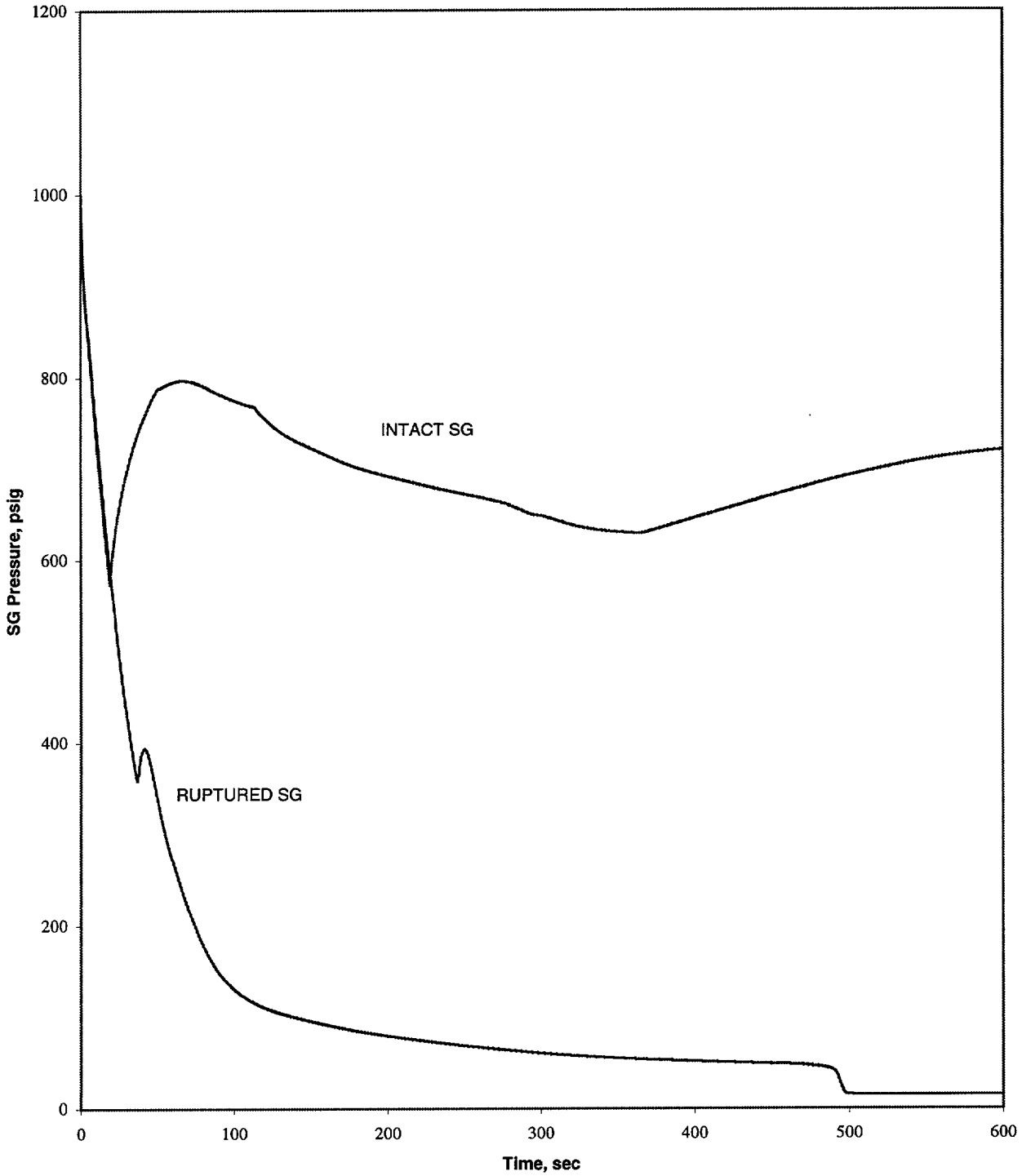


Figure 1.5.3-7

Hot Full Power with Loss of AC, Inside Containment Break
Reactivities vs. Time

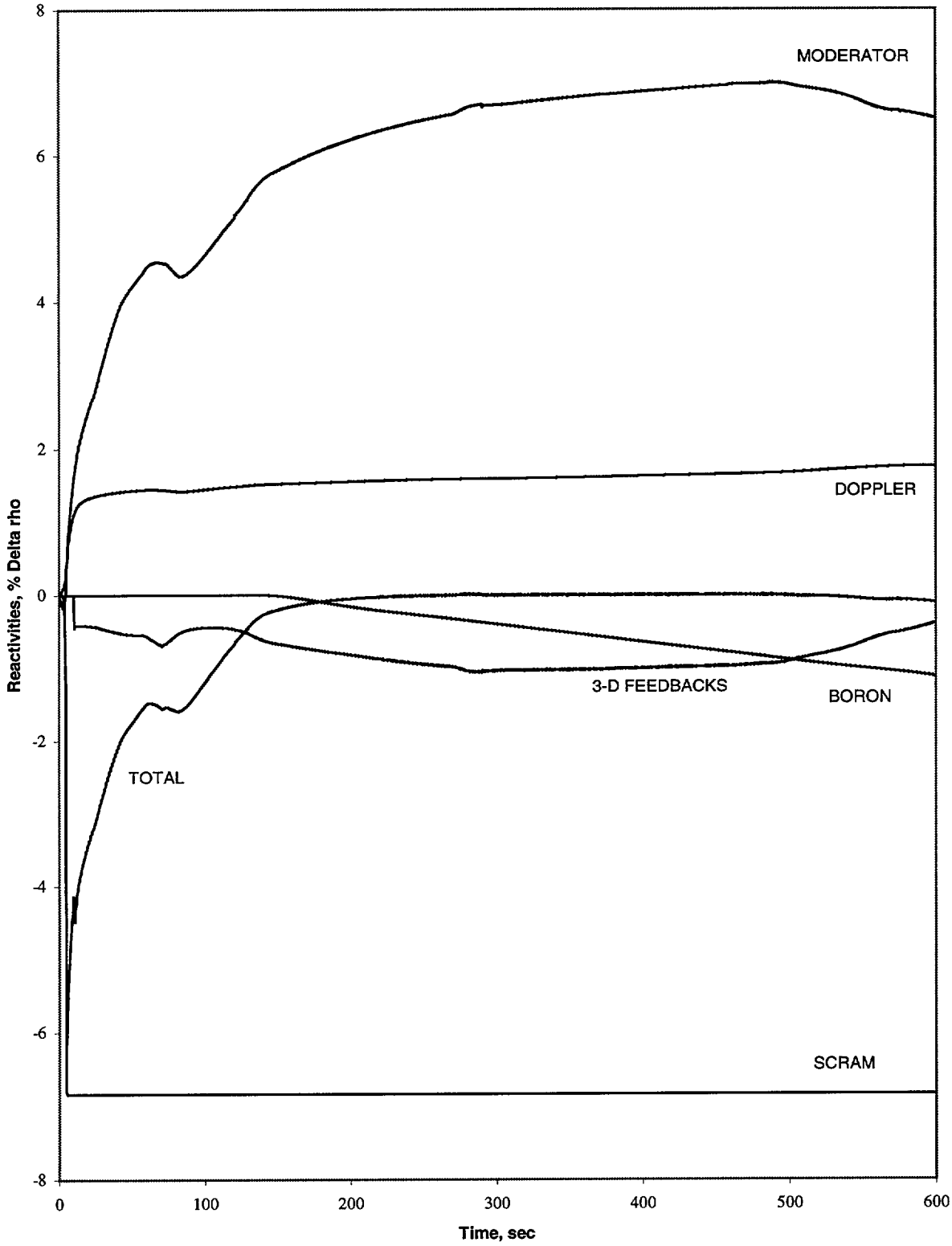


Figure 1.5.3-8

Hot Full Power with AC Available, Inside Containment Break
Core Power (3026 MWt Rated) vs. Time

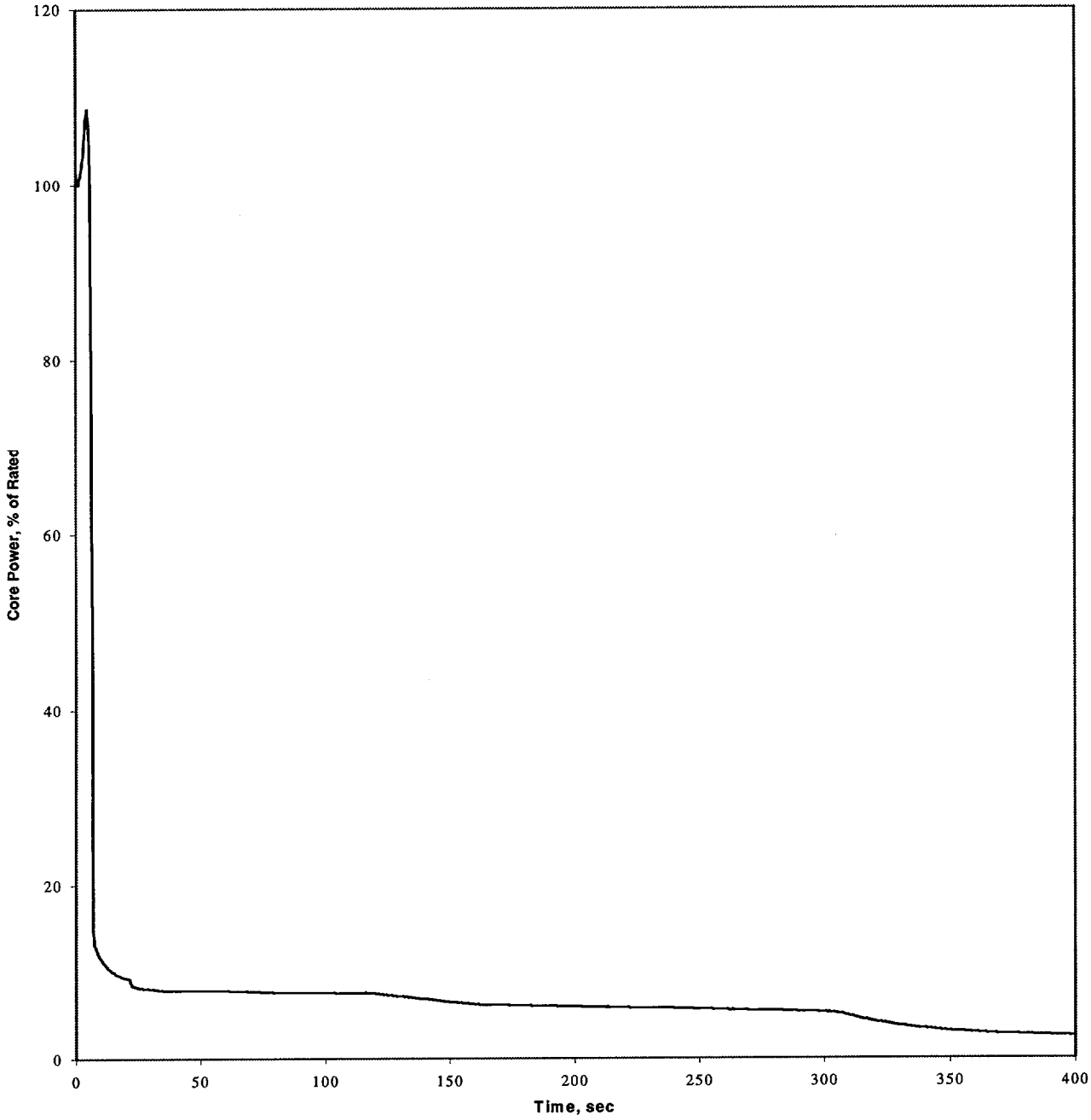


Figure 1.5.3-9

Hot Full Power with AC Available, Inside Containment Break
Core Average Heat Flux (3026 MWt Rated) vs. Time

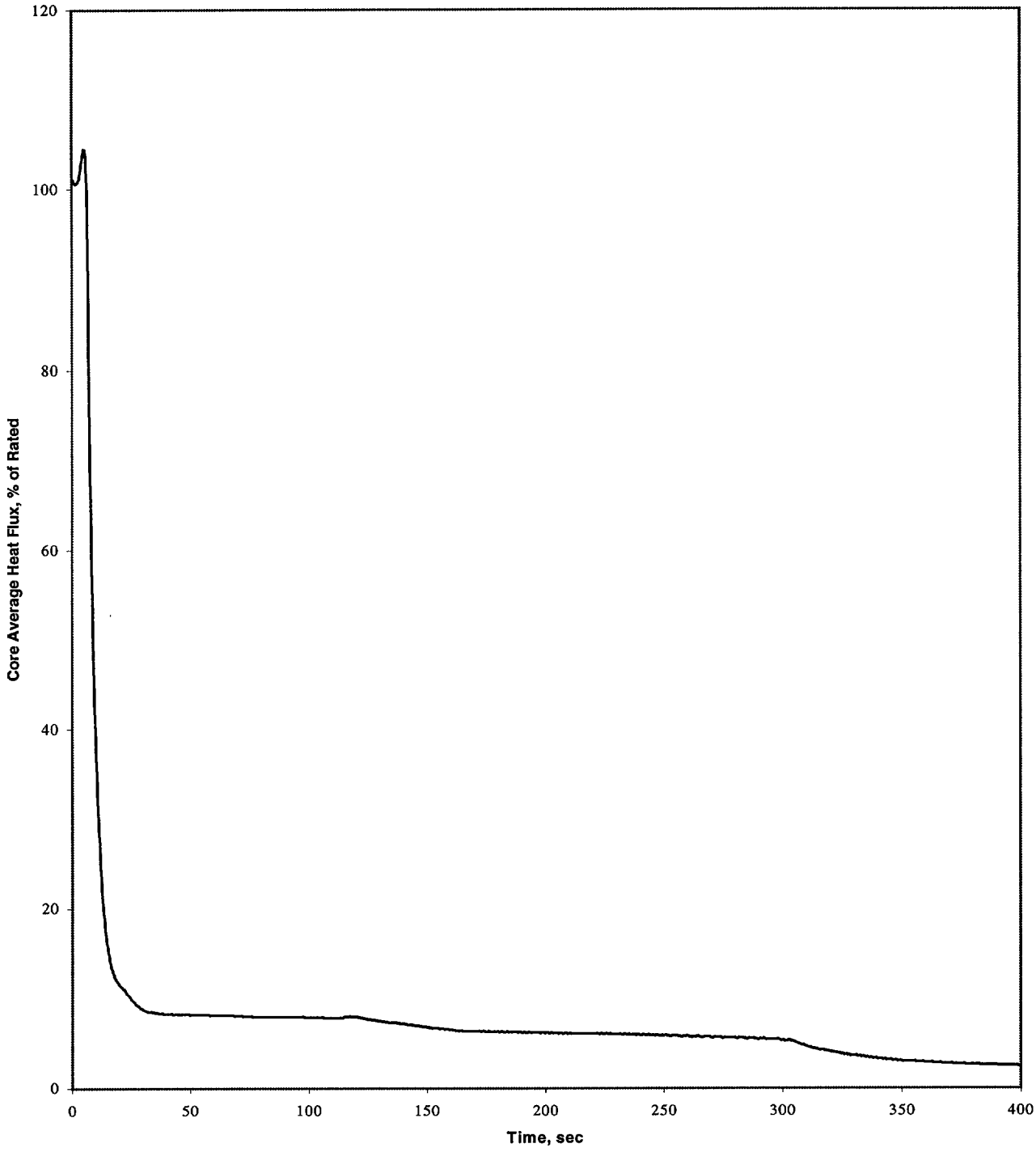


Figure 1.5.3-10

Hot Full Power with AC Available, Inside Containment Break
Reactor Coolant System Pressure vs. Time

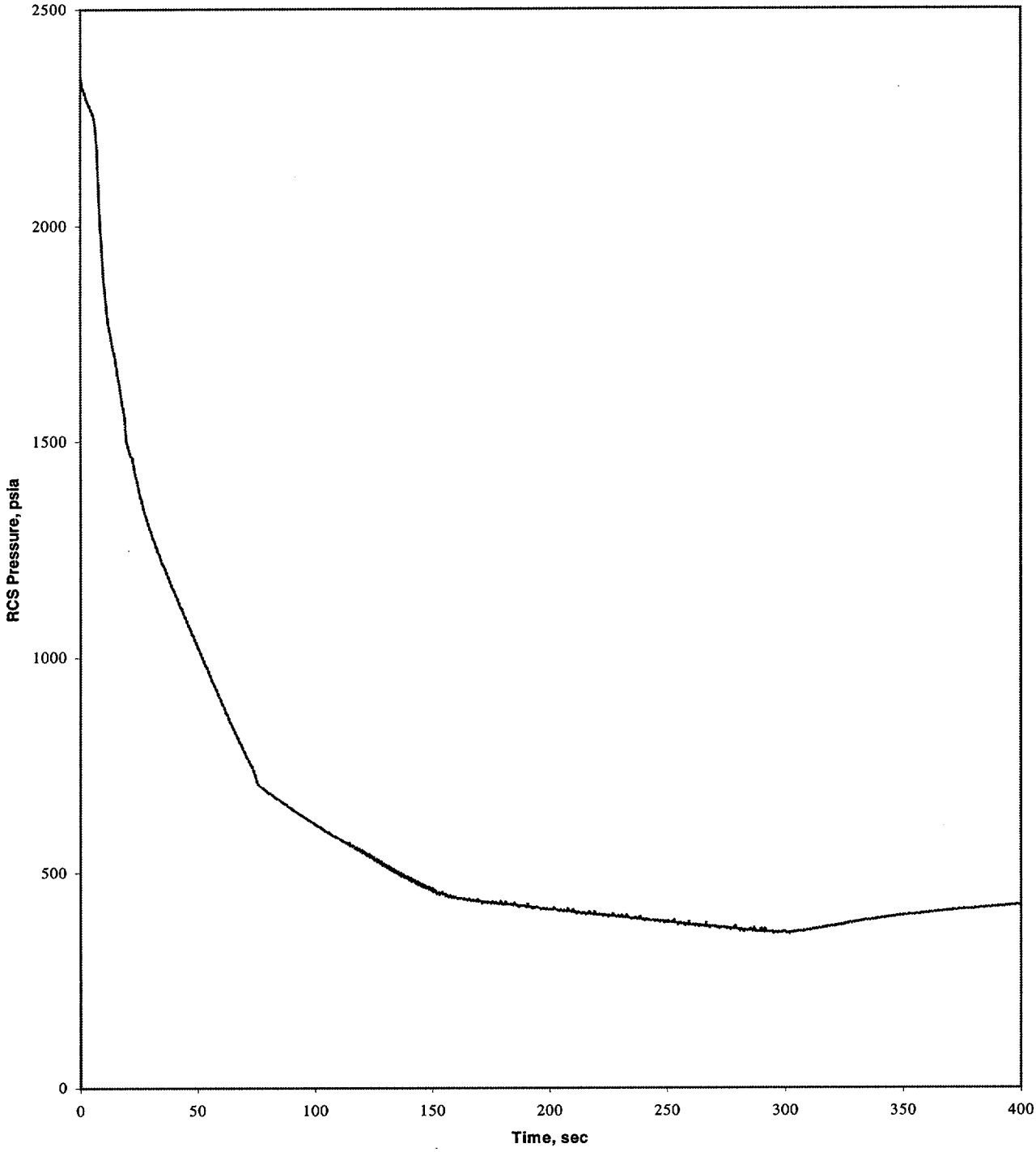


Figure 1.5.3-11

Hot Full Power with AC Available, Inside Containment Break
Reactor Coolant System Temperature vs. Time

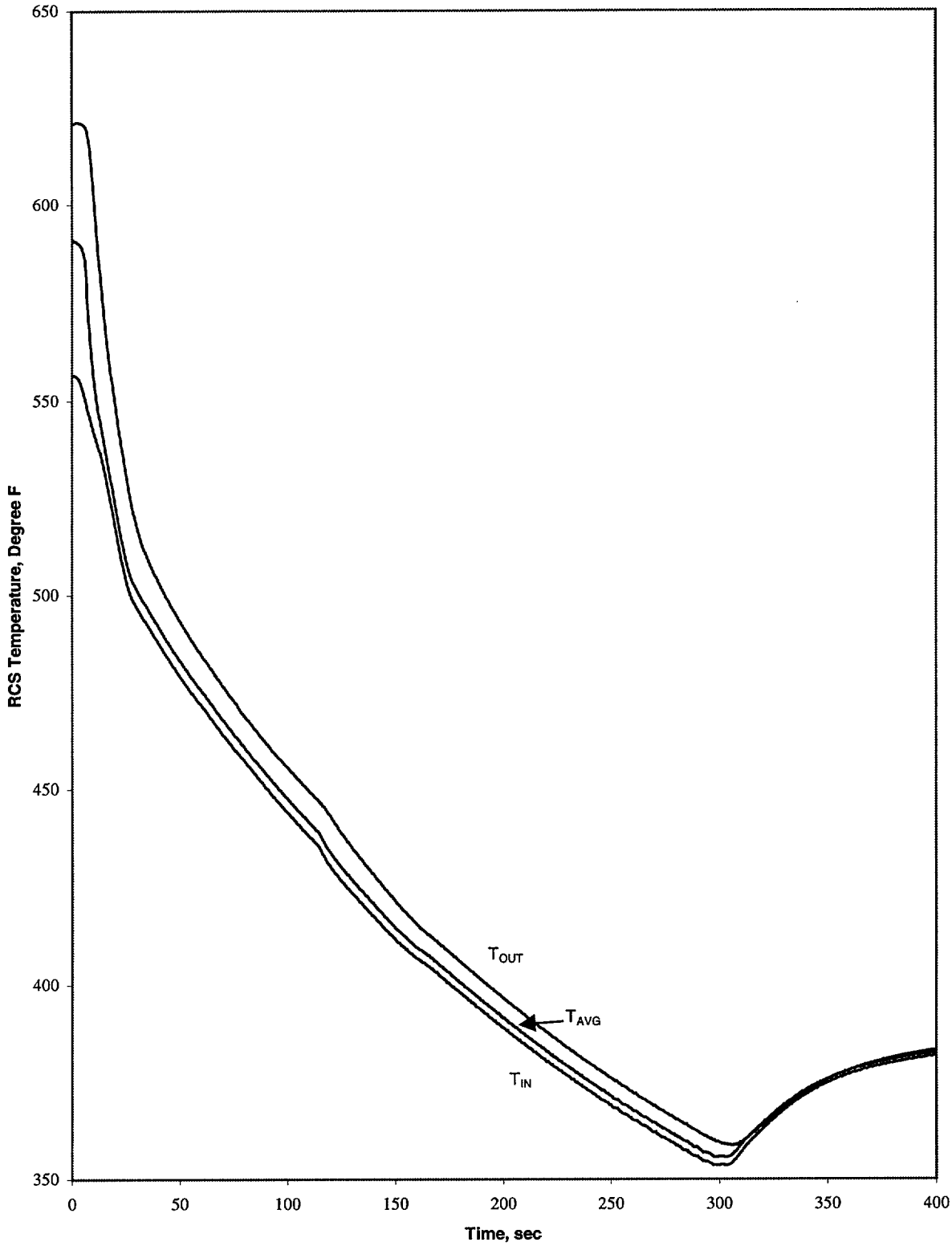


Figure 1.5.3-12

Hot Full Power with AC Available, Inside Containment Break
Steam Generator Pressure vs. Time

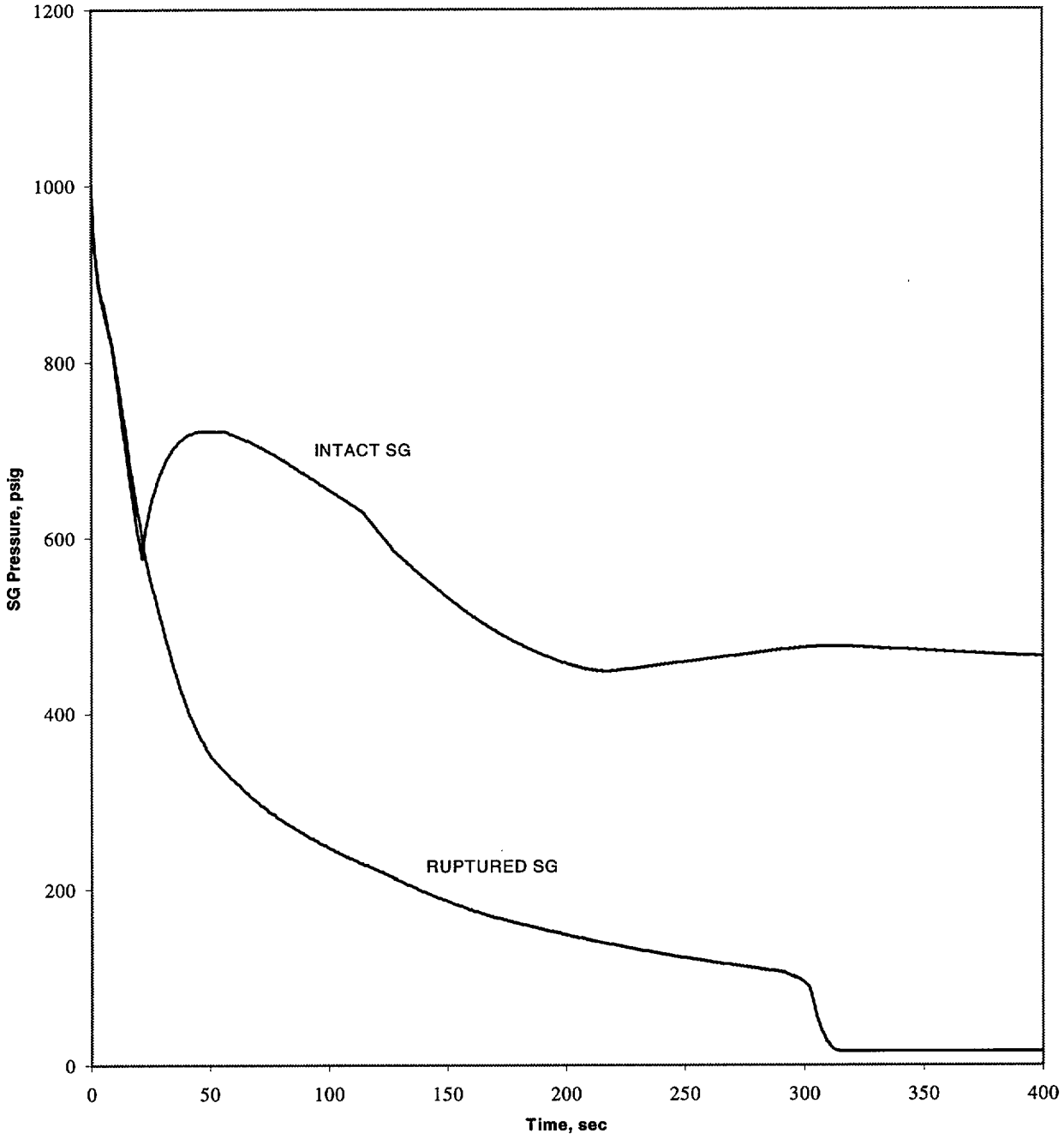


Figure 1.5.3-13

**Hot Full Power with AC Available, Inside Containment Break
Reactivities vs. Time**

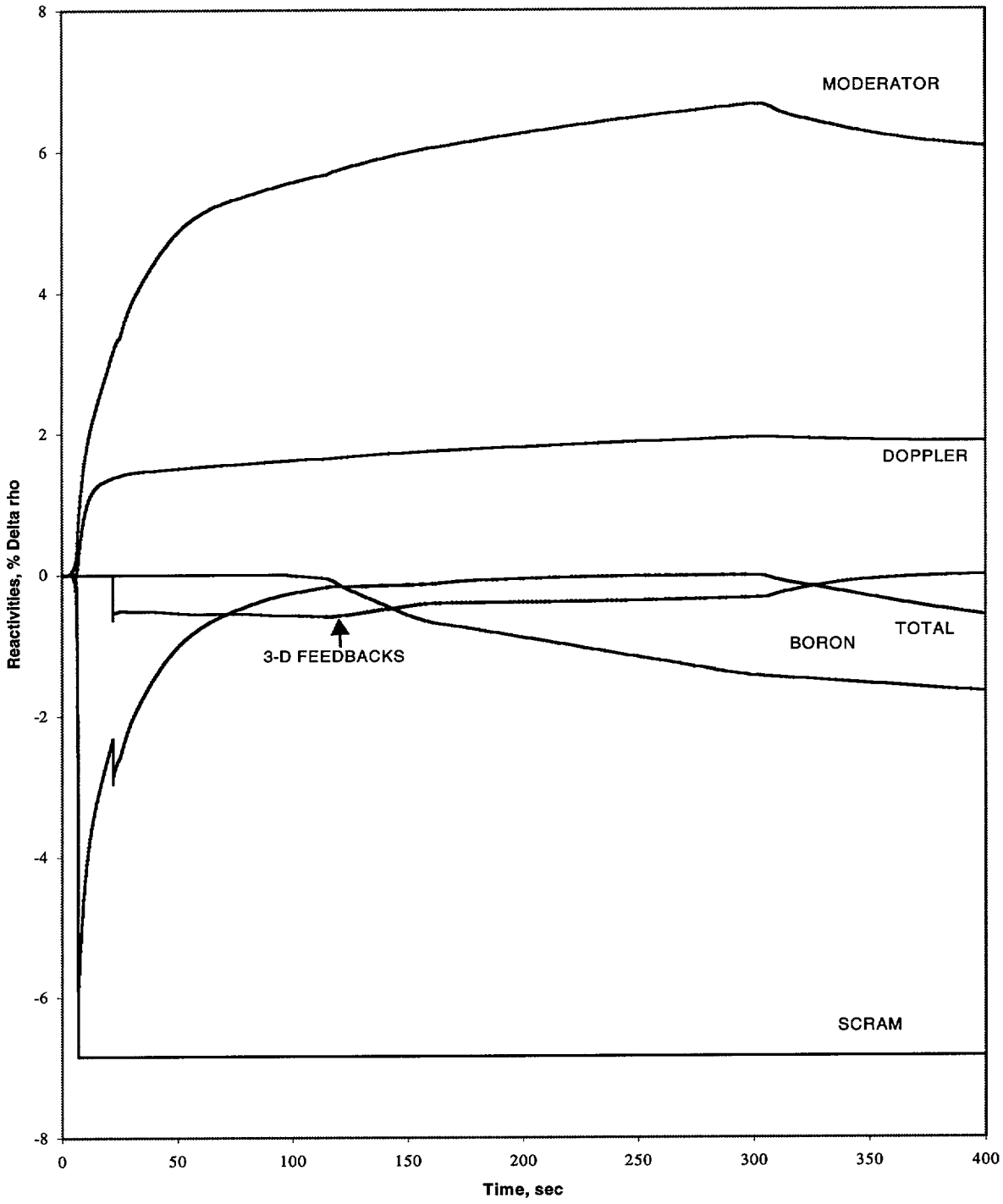


Figure 1.5.3-14

Hot Zero Power with Loss of AC, Inside Containment Break
Core Power (3026 MWt Rated) vs. Time

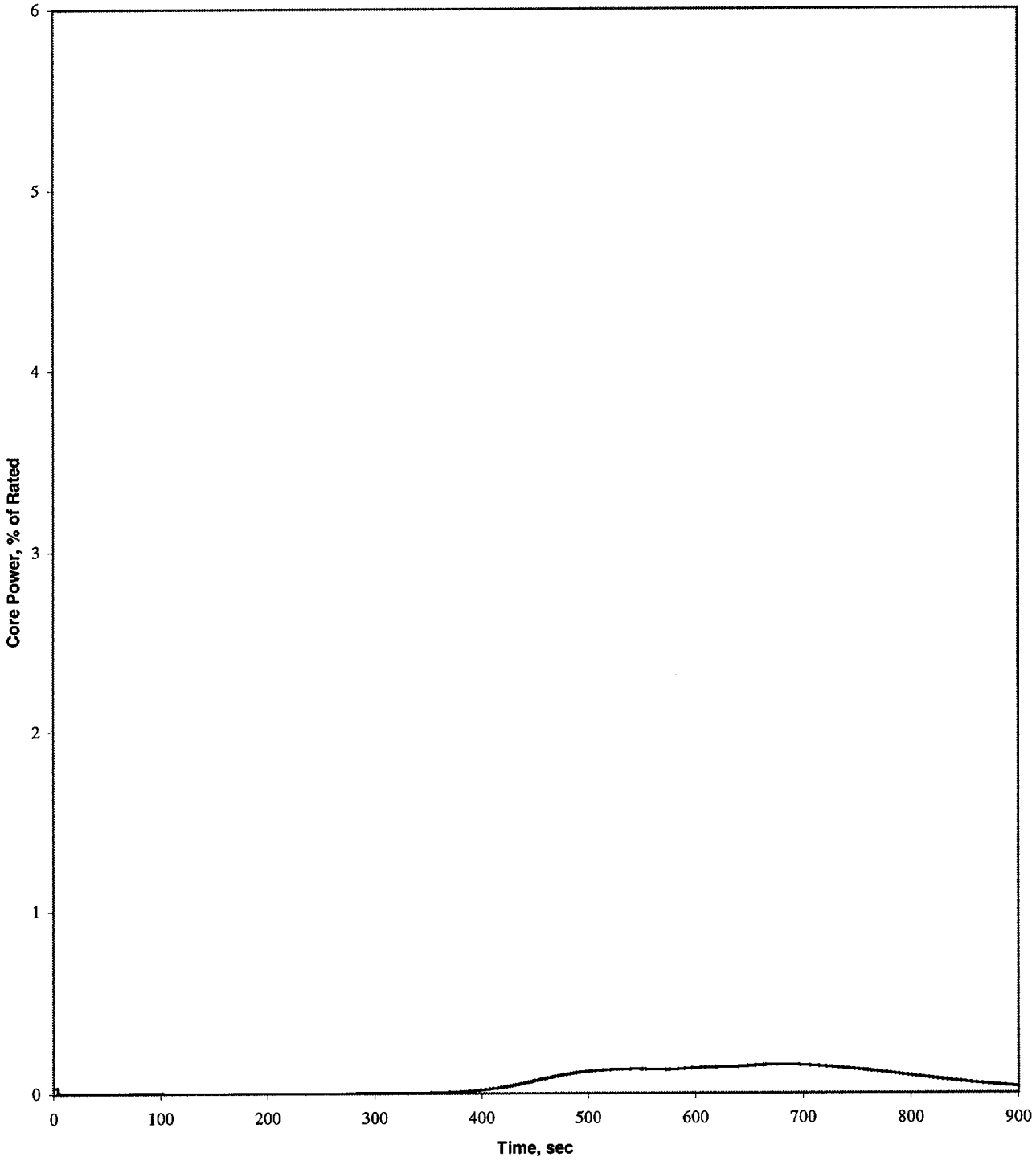


Figure 1.5.3-15

Hot Zero Power with Loss of AC, Inside Containment Break
Core Average Heat Flux (3026 MWt Rated) vs. Time

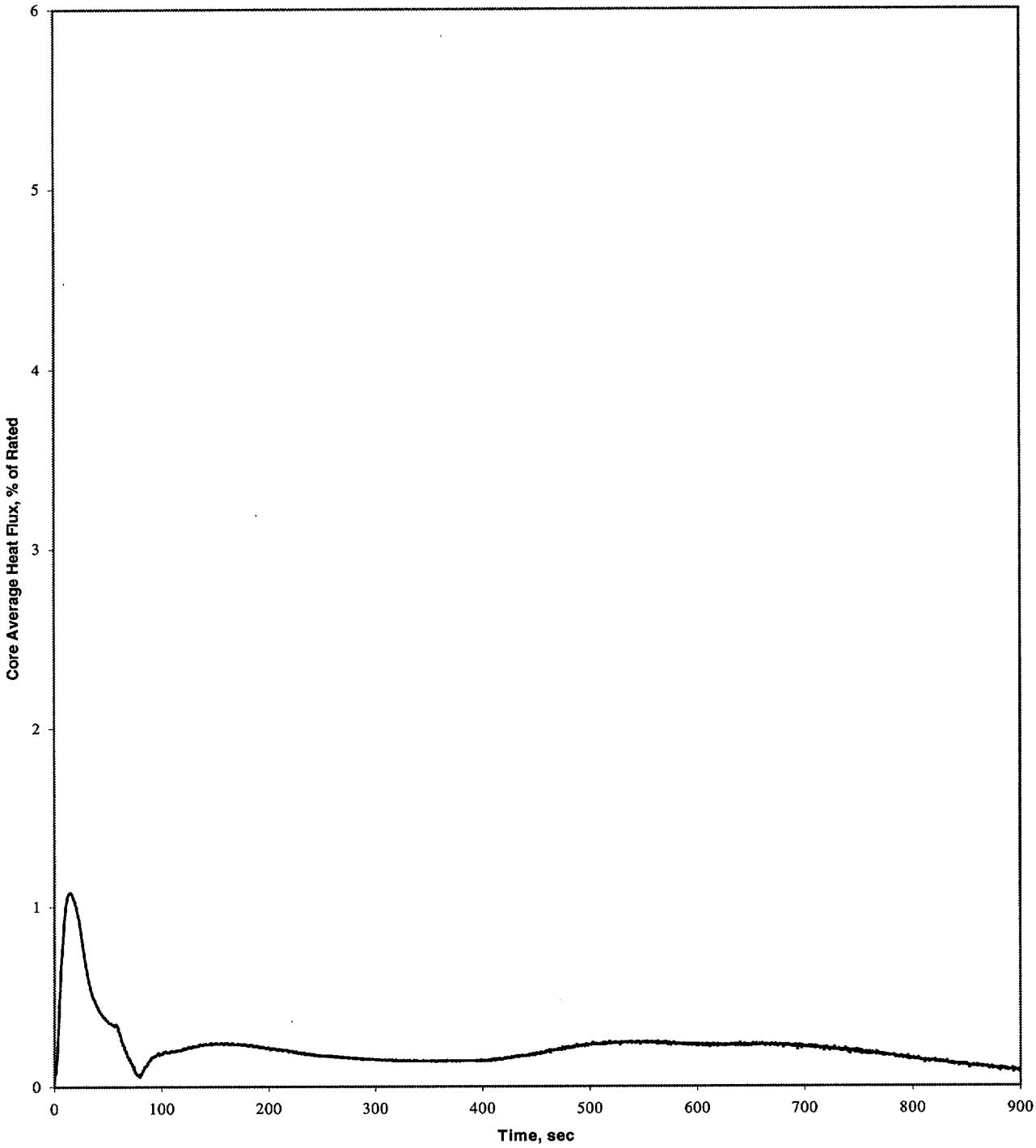


Figure 1.5.3-16

Hot Zero Power with Loss of AC, Inside Containment Break
Reactor Coolant System Pressure vs. Time

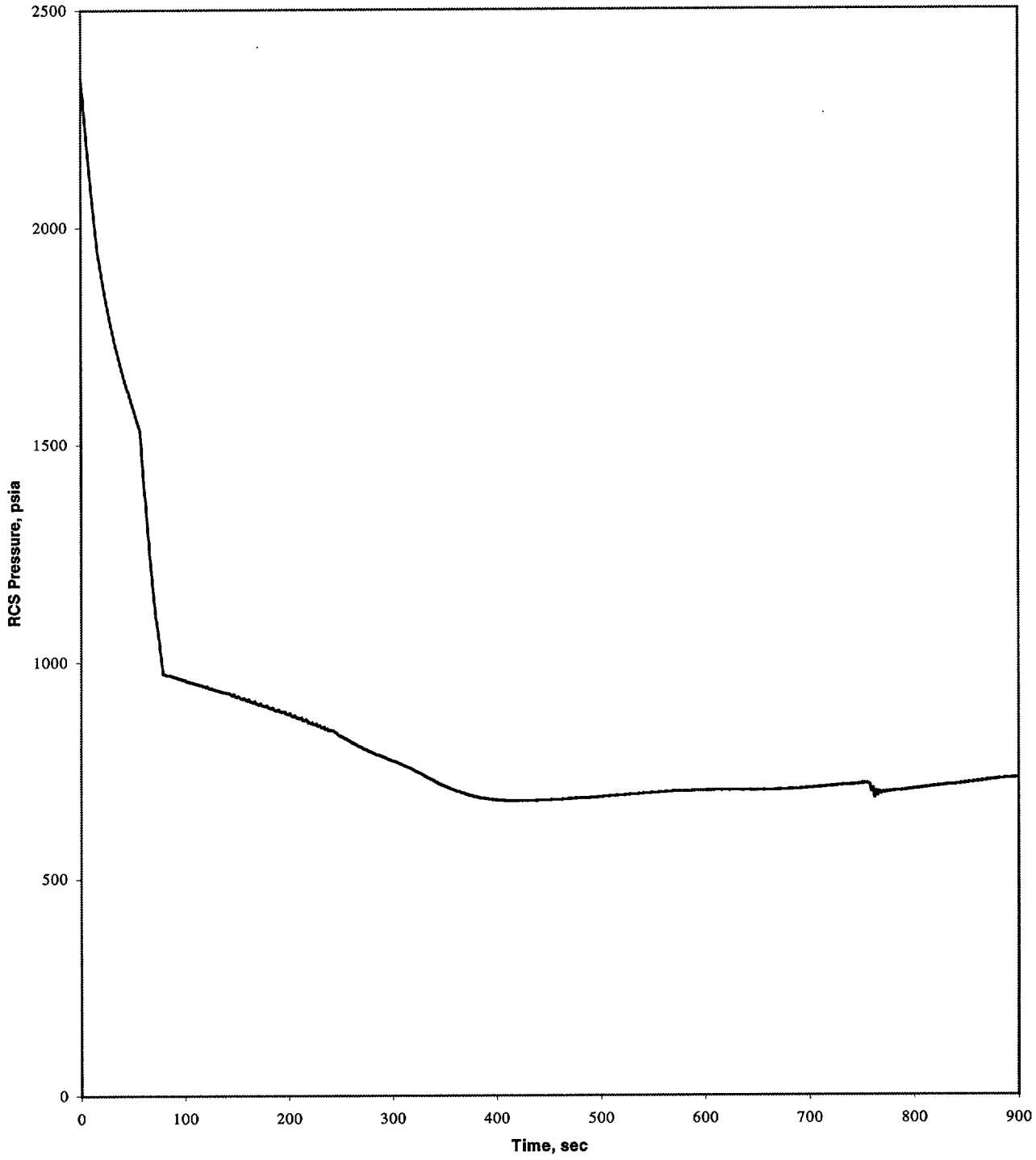


Figure 1.5.3-17

Hot Zero Power with Loss of AC, Inside Containment Break
Reactor Coolant System Temperature vs. Time

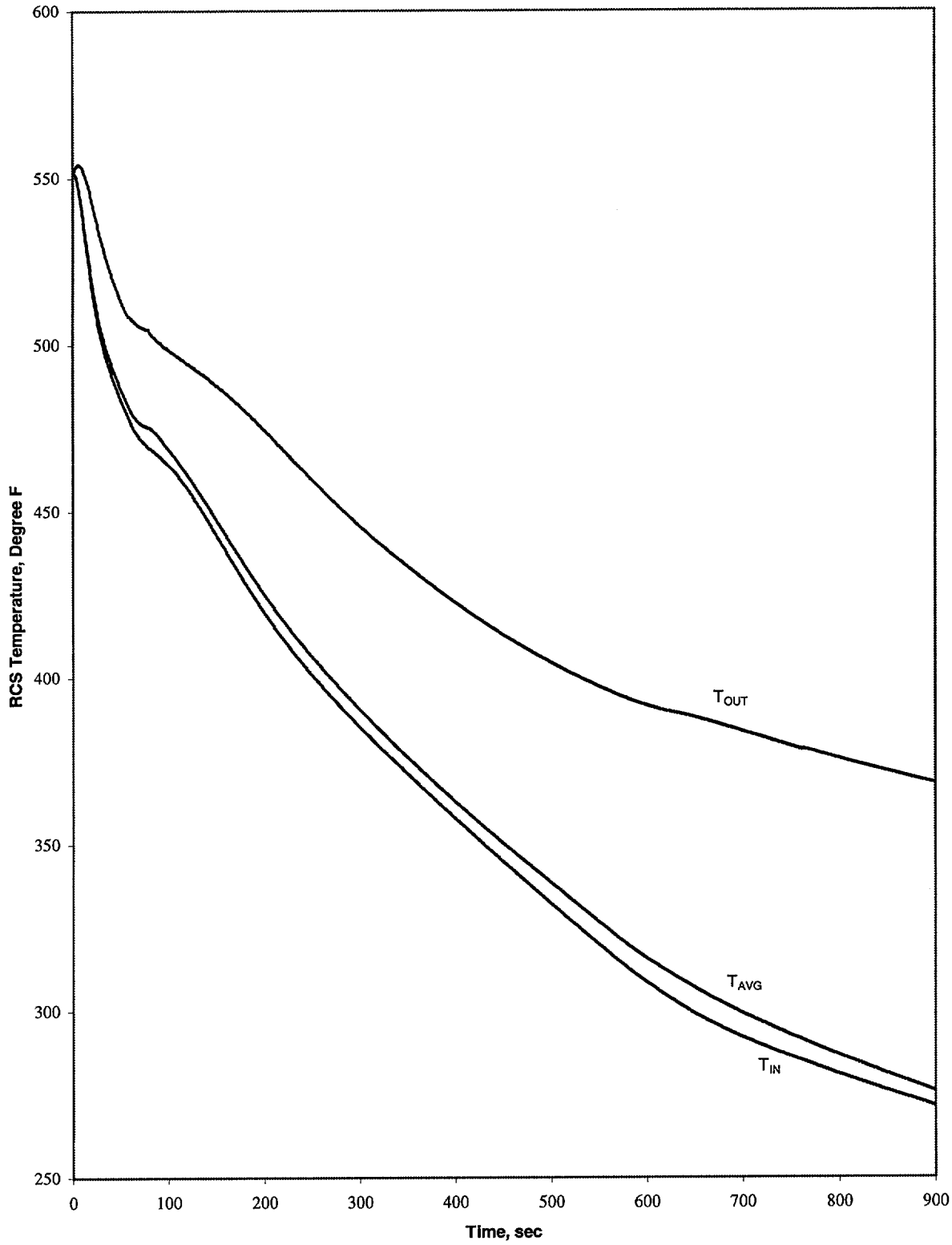


Figure 1.5.3-18

Hot Zero Power with Loss of AC, Inside Containment Break
Steam Generator Pressure vs. Time

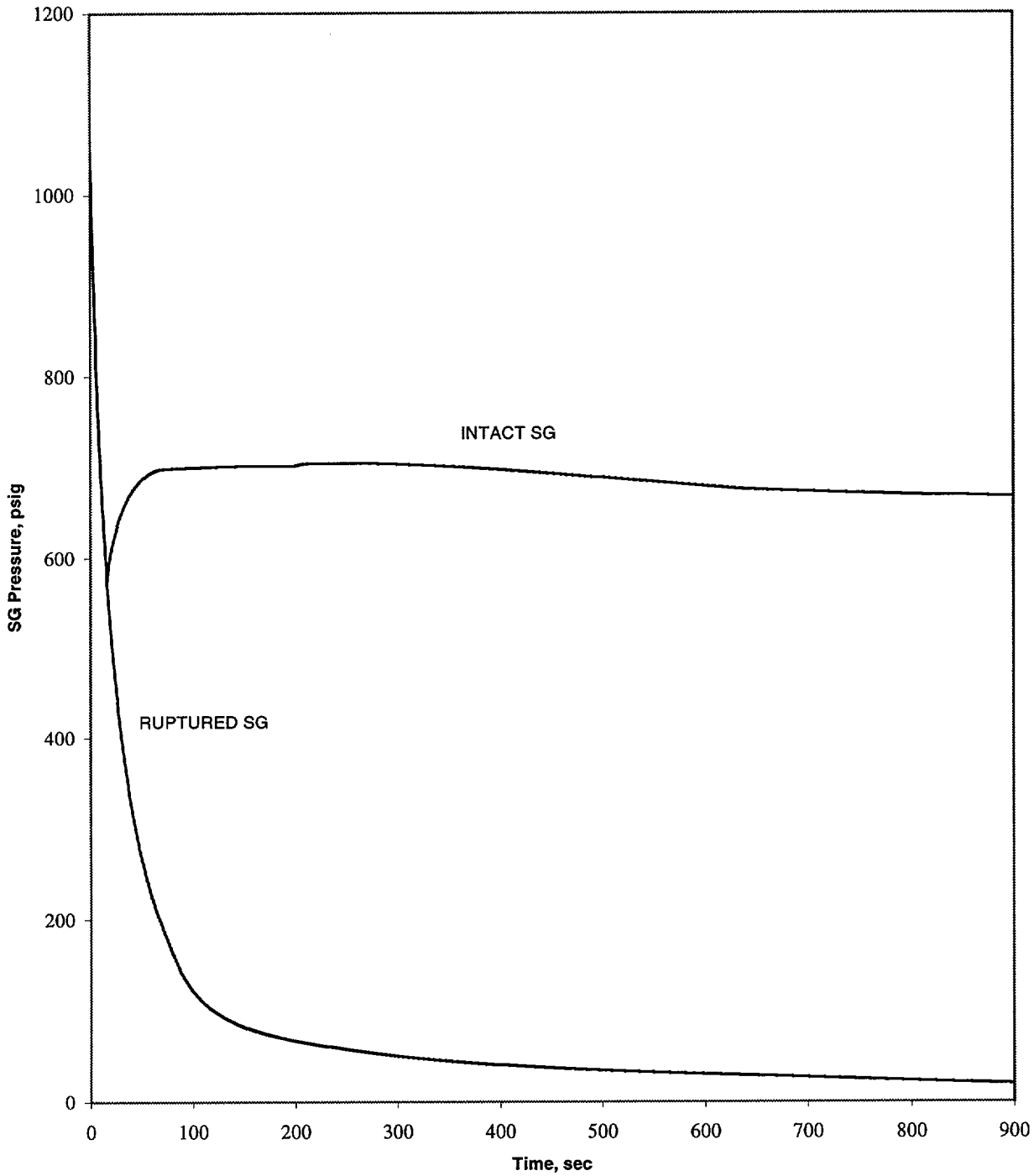


Figure 1.5.3-19

Hot Zero Power with Loss of AC, Inside Containment Break
Reactivities vs. Time

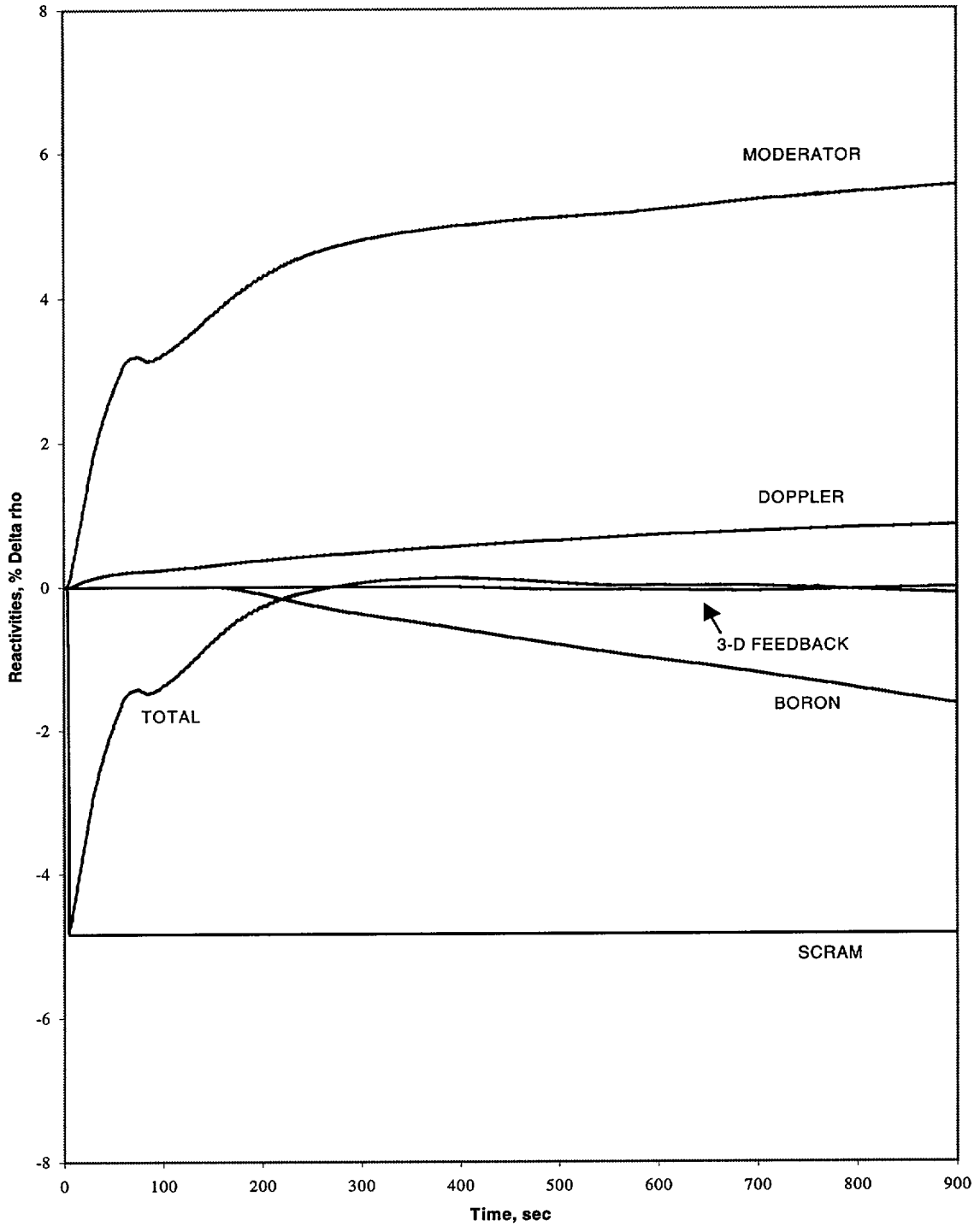


Figure 1.5.3-20

Hot Zero Power with AC Available, Outside Containment Break
Core Power (3026 MWt Rated) vs. Time

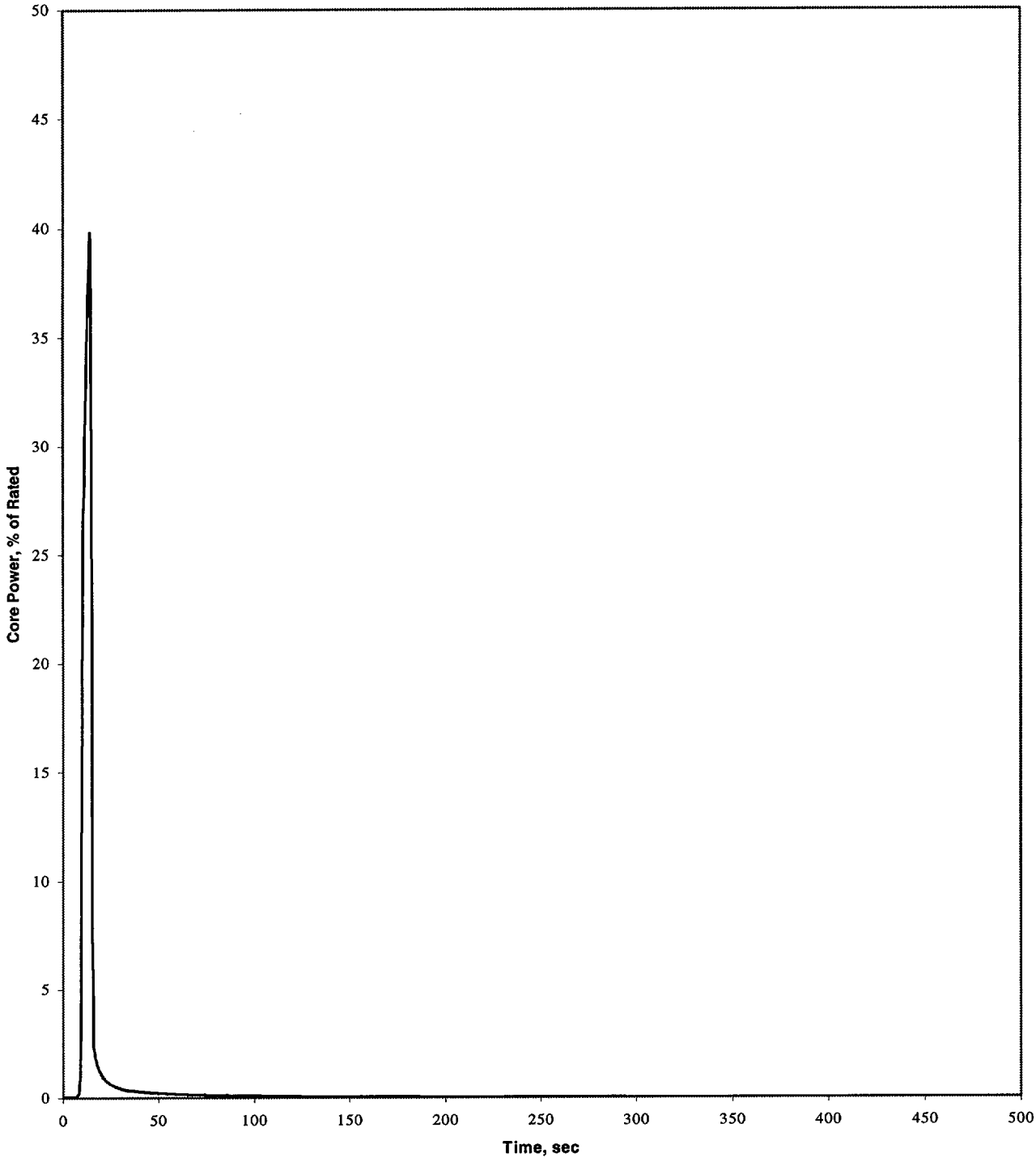


Figure 1.5.3-21

Hot Zero Power with AC Available, Outside Containment Break
Core Average Heat Flux (3026 MWt Rated) vs. Time

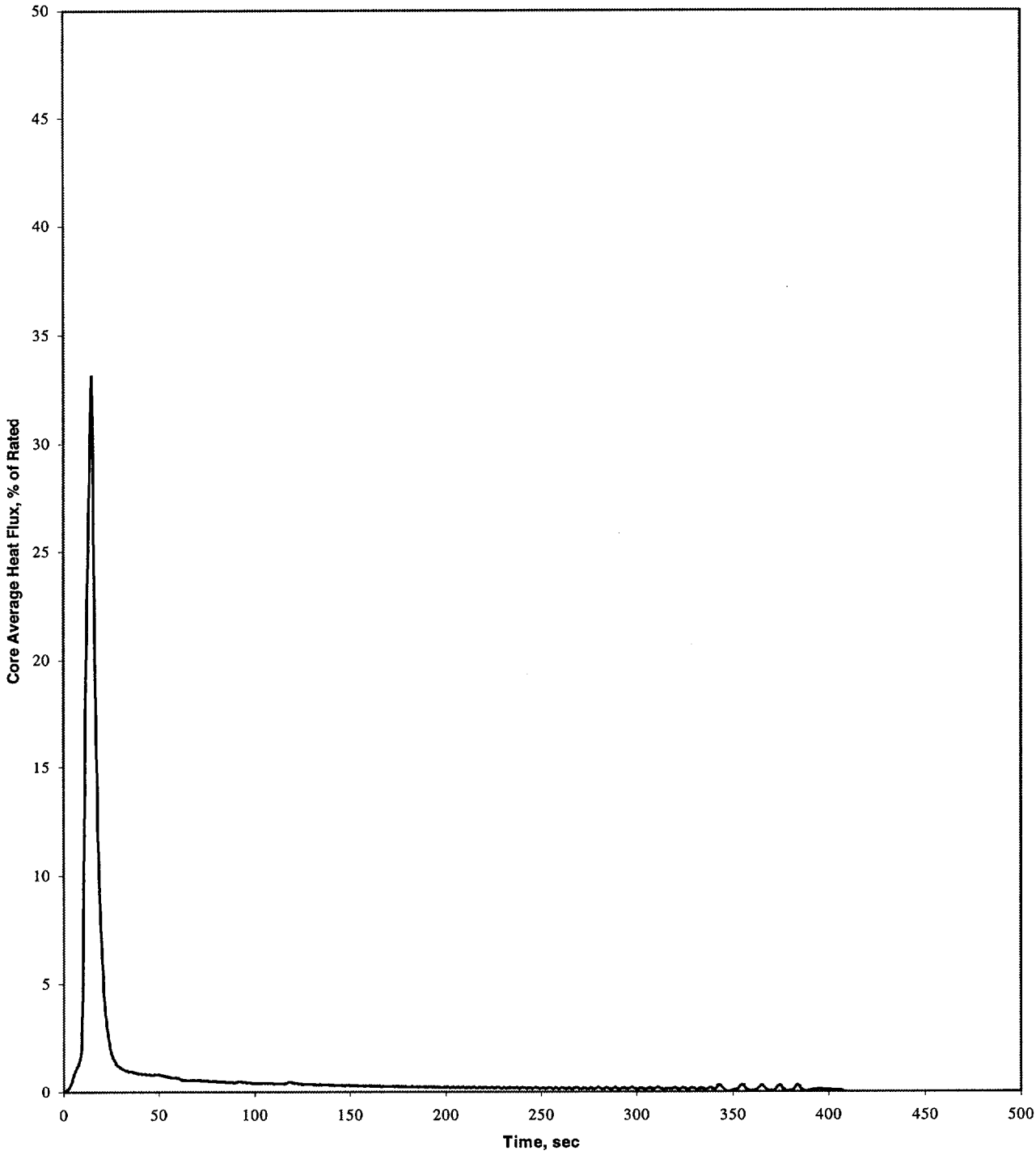


Figure 1.5.3-22

Hot Zero Power with AC Available, Outside Containment Break
Reactor Coolant System Pressure vs. Time

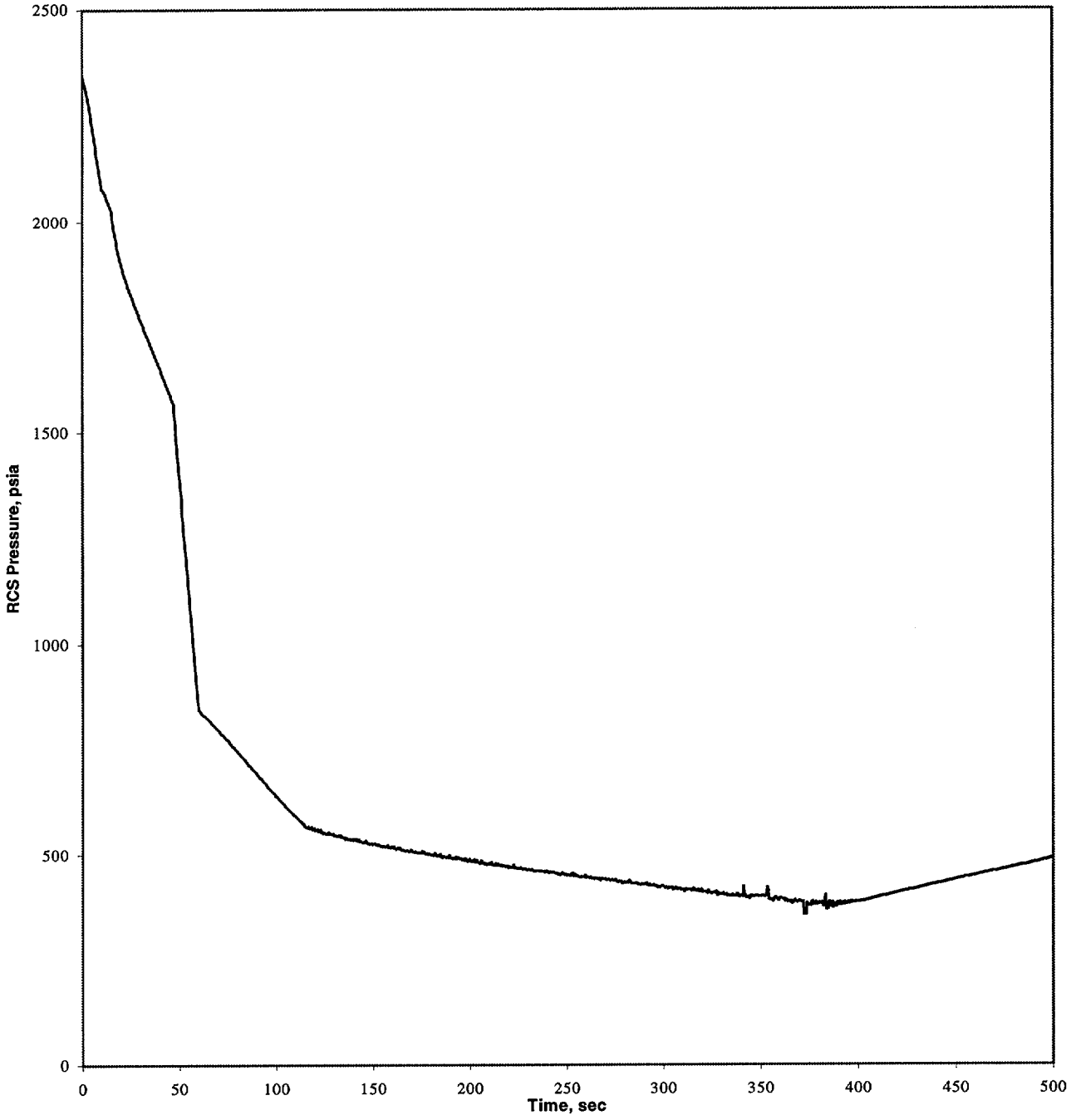


Figure 1.5.3-23

Hot Zero Power with AC Available, Outside Containment Break
Reactor Coolant System Temperature vs. Time

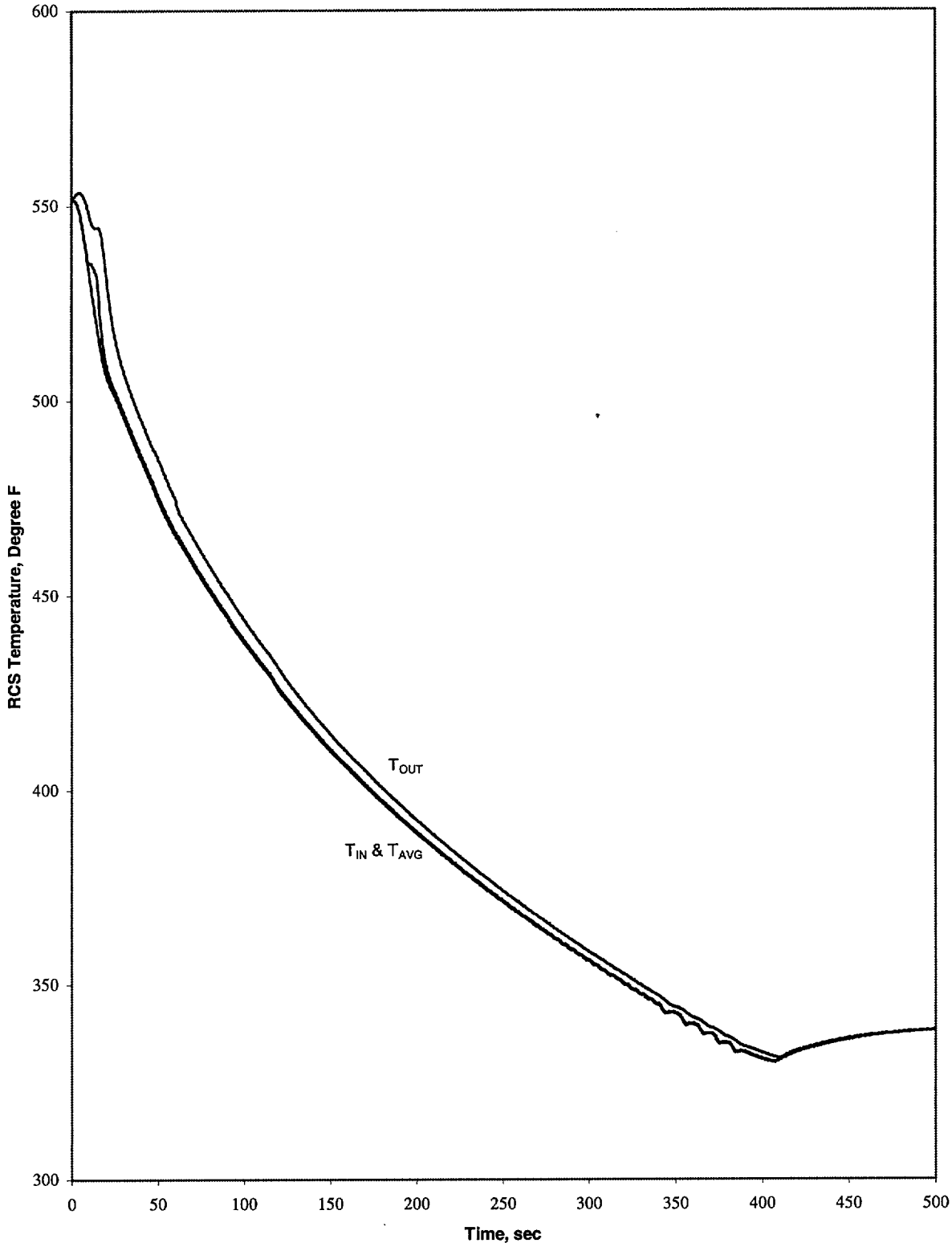


Figure 1.5.3-24

Hot Zero Power with AC Available, Outside Containment Break
Steam Generator Pressure vs. Time

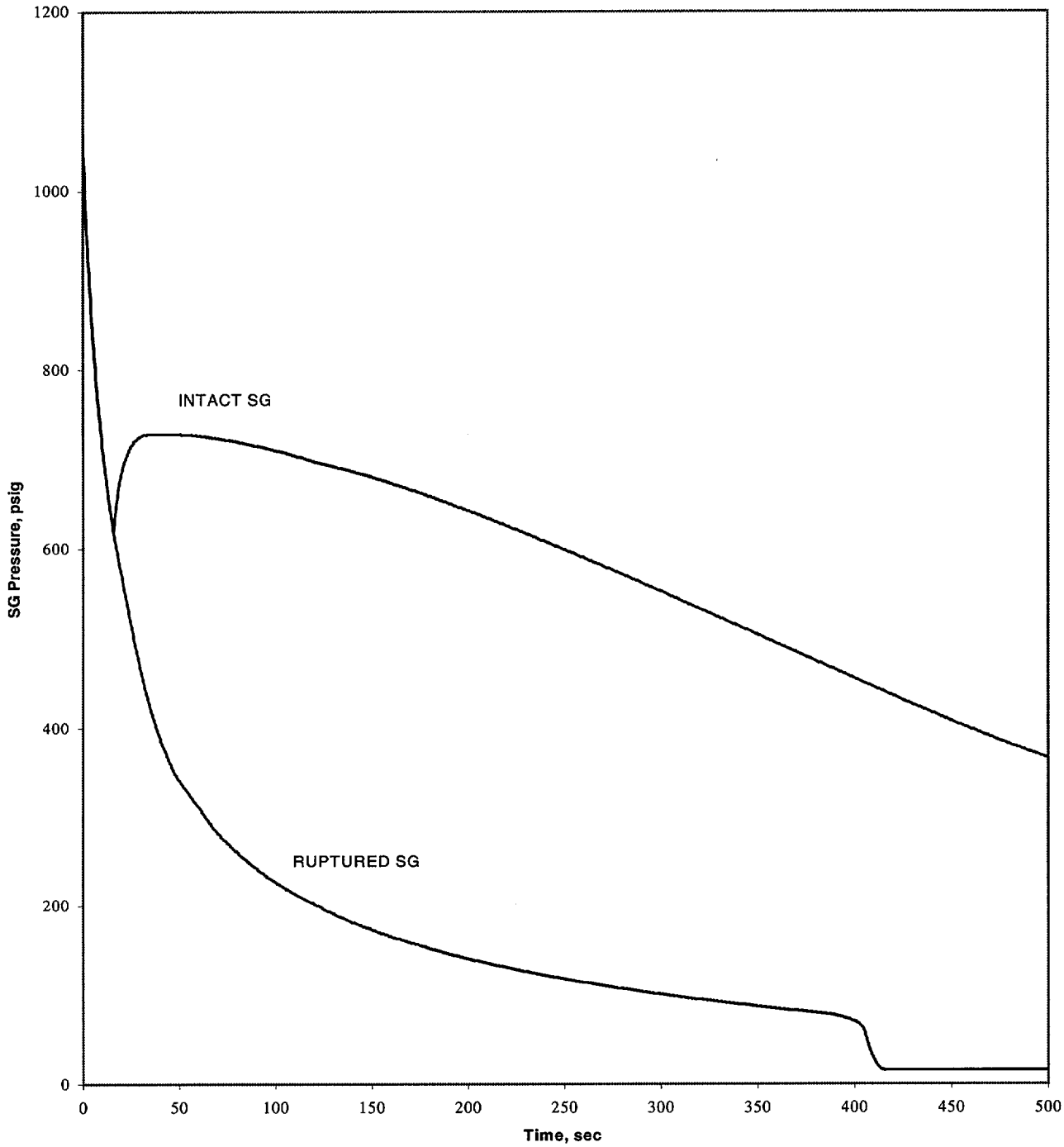


Figure 1.5.3-25

**Hot Zero Power with AC Available, Outside Containment Break
Reactivities vs. Time**

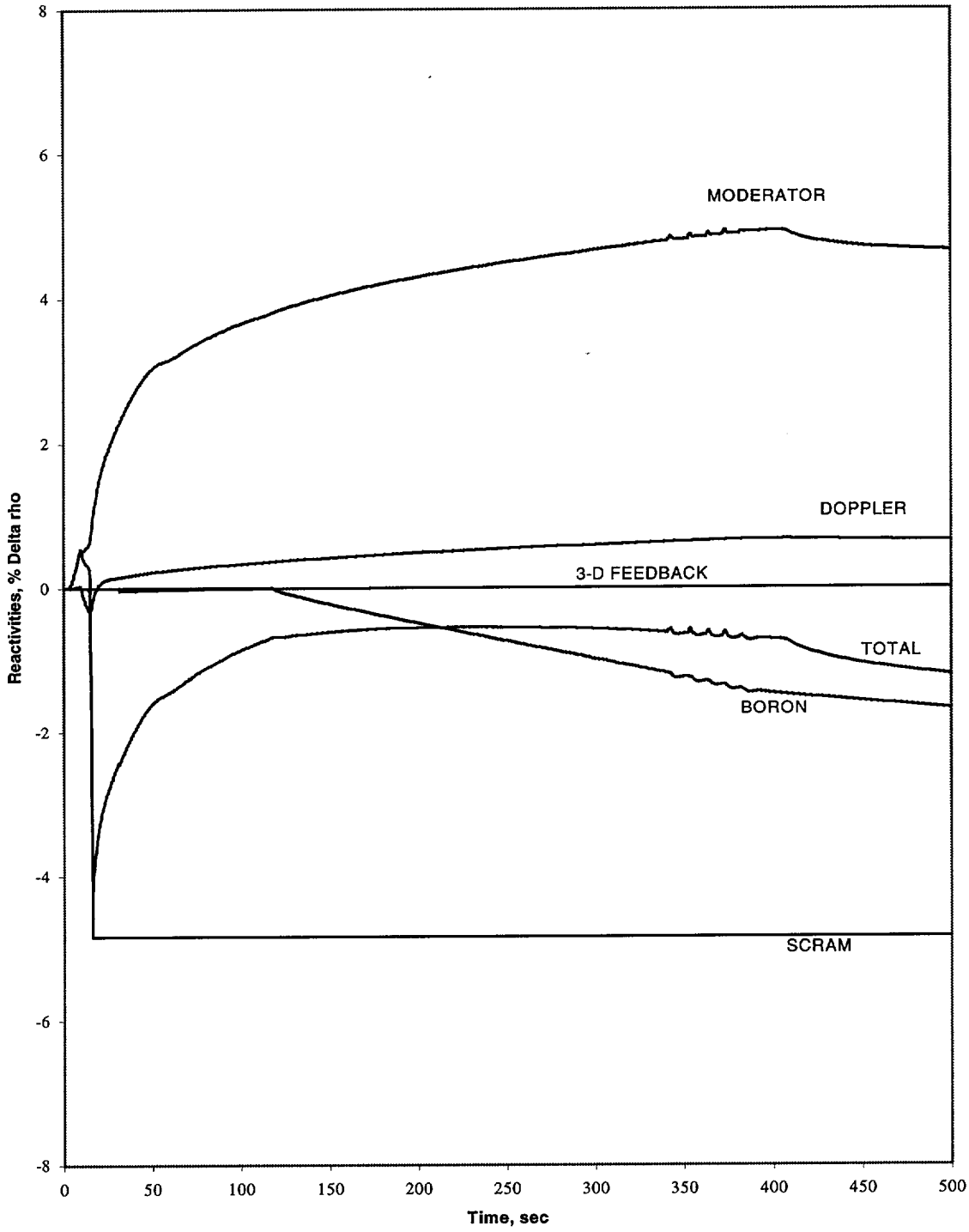


Figure 1.7-1

**Asymmetric Steam Generator Transient
Core Power (3026 MWt Rated) vs. Time**

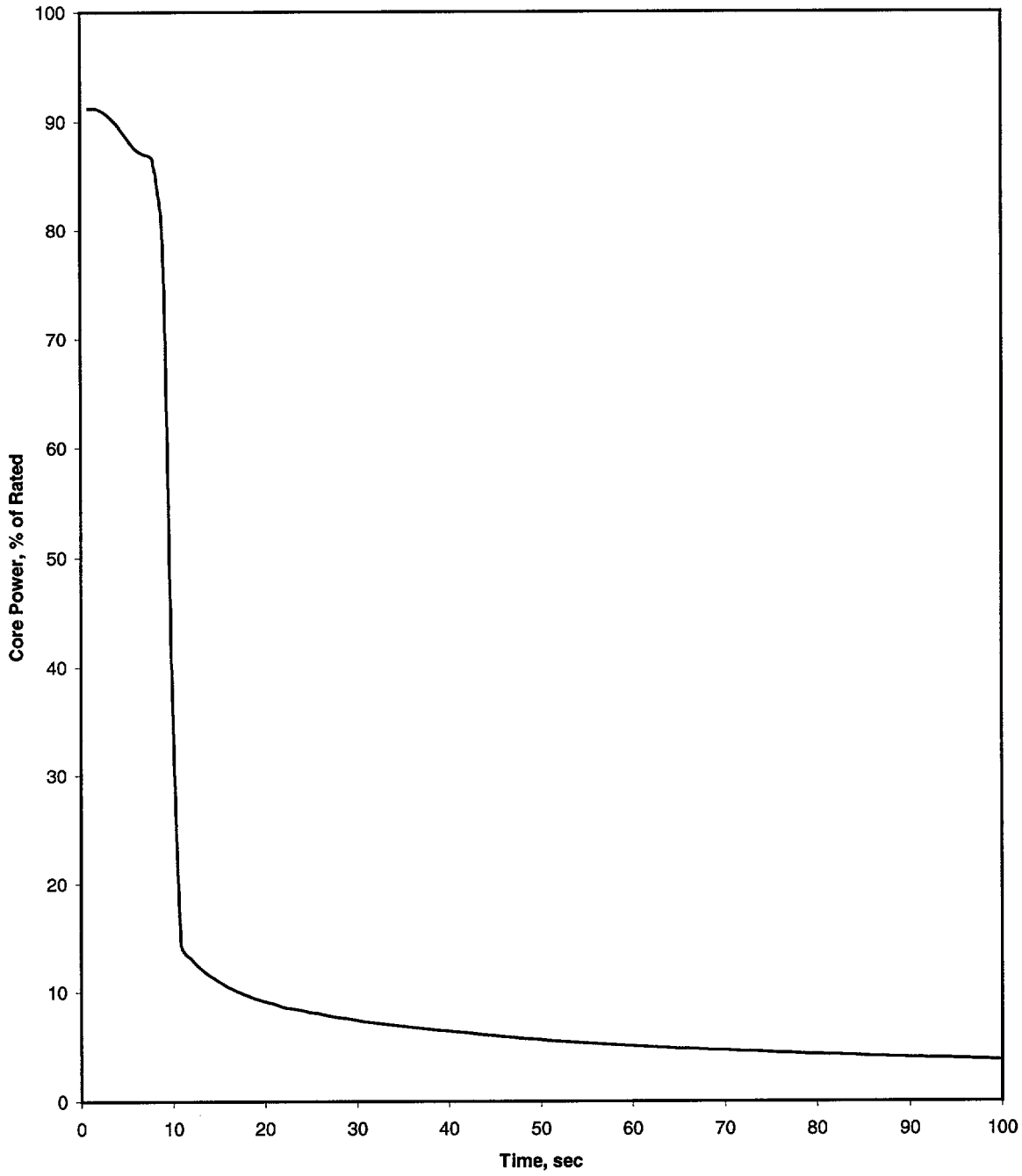


Figure 1.7-2

Asymmetric Steam Generator Transient
Core Average Heat Flux (3026 MWt Rated) vs. Time

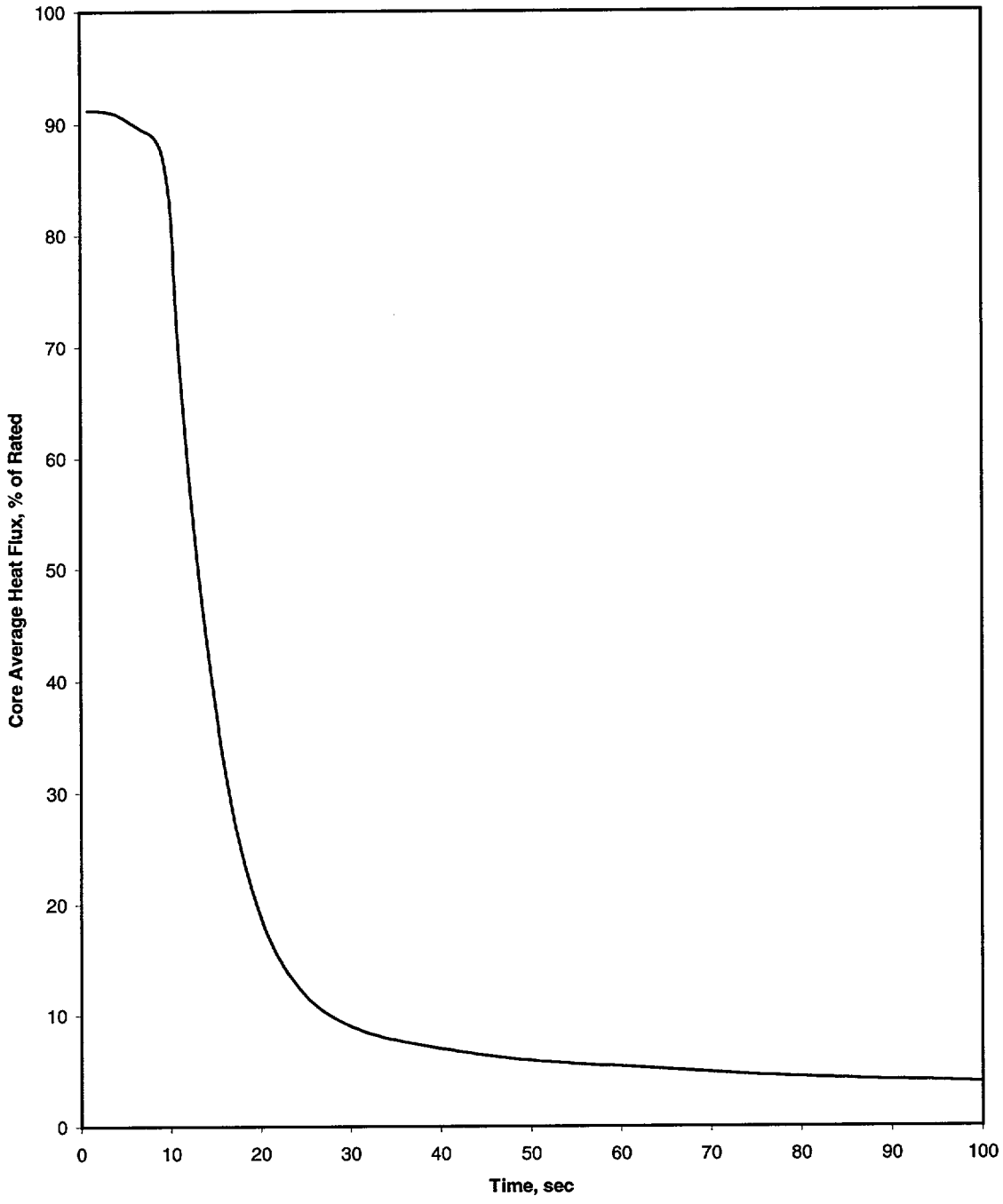


Figure 1.7-3

Asymmetric Steam Generator Transient
Reactor Coolant System Pressure vs. Time

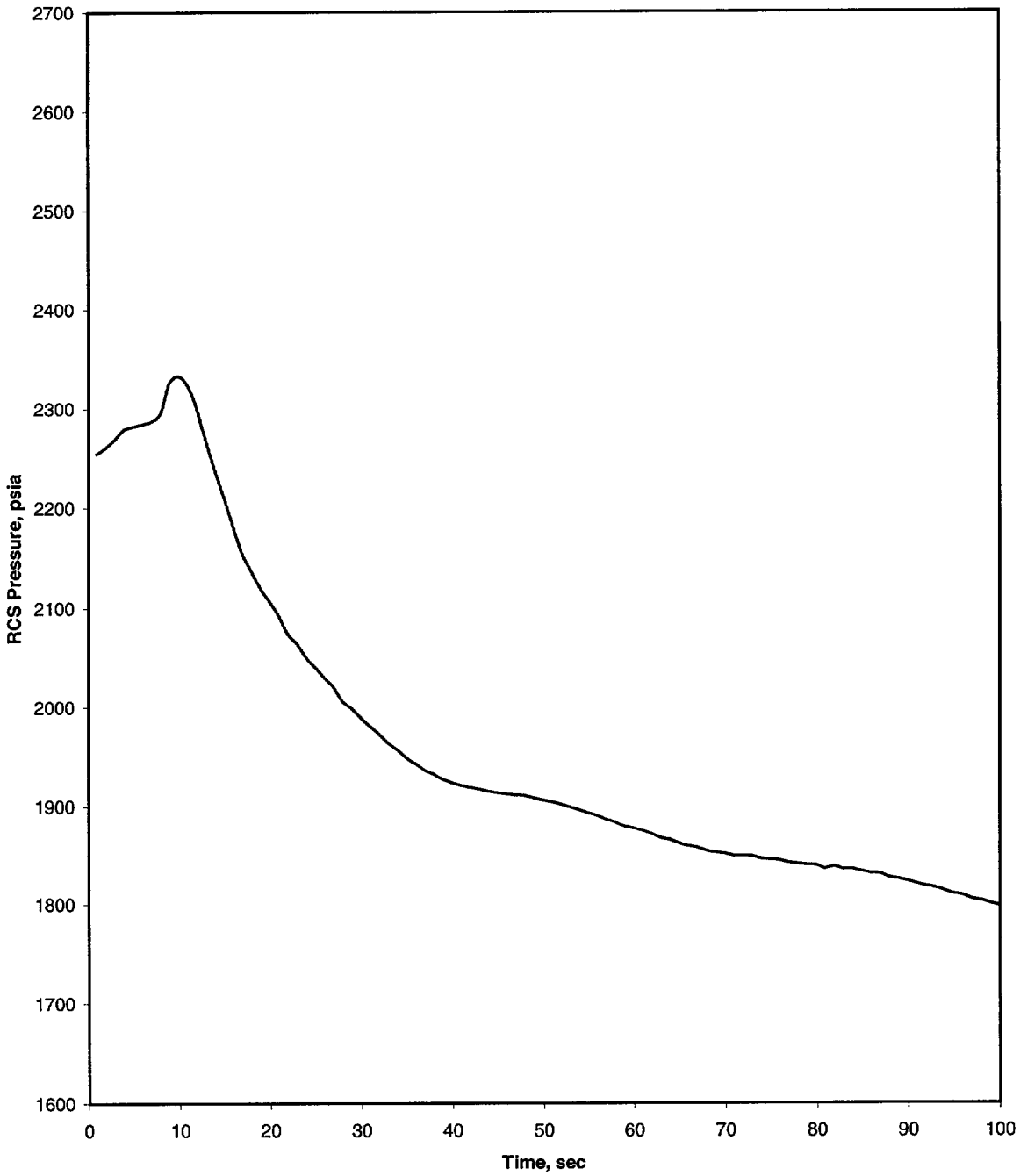


Figure 1.7-4

**Asymmetric Steam Generator Transient
Reactor Coolant System Temperatures vs. Time**

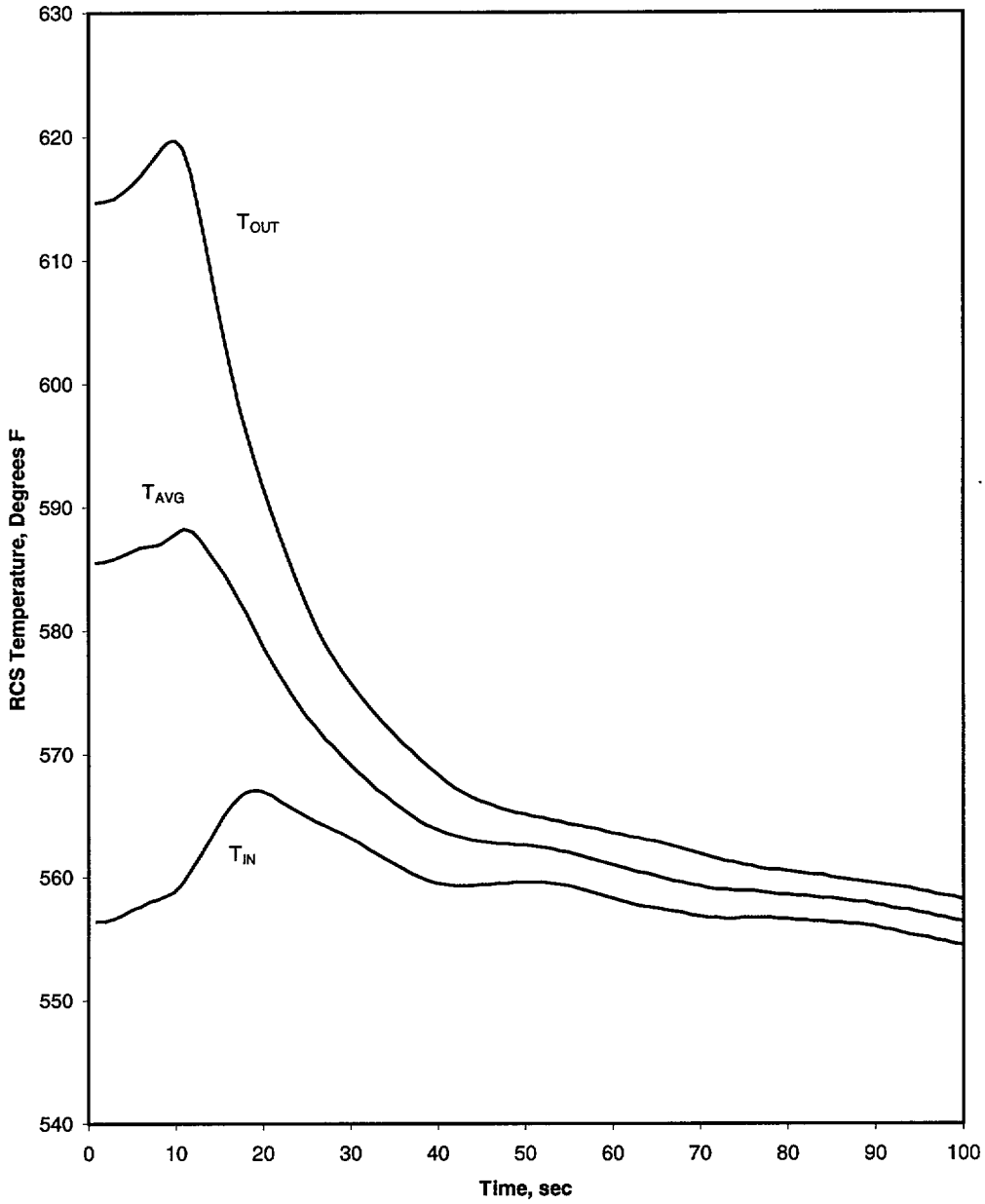


Figure 1.7-5

**Asymmetric Steam Generator Transient
Steam Generator Pressure vs. Time**