ACCIDENT ANALYSES

CHAPTER 15

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15 ACCIDENT ANALYSIS

15.0 ORGANIZATION AND METHODOLOGY

This chapter presents analytical evaluation of the response of the Nuclear Steam Supply System (NSSS), "to postulated disturbances in process variables and to postulated malfunctions or failures of equipment," (Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," September, 1975 (R2)). Such initiating events are postulated and their consequences analyzed despite the many precautions which are taken in the design, construction, quality assurance, and plant operation to prevent their occurrence. The effects of these initiating events are examined, "to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations (or to identify the limitations of expected performance.)"[1]

Chapter 15 is updated to include the current cycle information and provides description of analyses supporting design and performance for the operation of St. Lucie Unit 2 at a power rating of 3020 MWt. St. Lucie Unit 2 first fuel cycle utilized Batch A, B, and C fuel assemblies at a licensed core power level of 2560 MWt. Operation of Cycle 1 continued at or near licensed power. Cycle 1 terminated on October 21, 1984. Operation of Cycle 2 commenced in November, 1984, and terminated in April, 1986 at a licensed core power level of 2700 MWt.

Sections 15.0.1 through 15.0.4 contain design information describing Cycles 1 and 2. Although these sections are retained for historical purposes, they are referred to in other sections where applicable to later cycles. Other sections referred to in these sections are historical sections which are no longer existing in the current UFSAR.

Sections starting from 15.0.5 reflect the current cycle information, pertaining to accident analyses are described beginning with Section 15.1.

Section 15.0.19 summarizes the effects of the Extended Power Uprate (EPU) on the accident analyses presented in Chapter 15 of the St. Lucie Unit 2 UFSAR performed by Westinghouse Electric Company LLC.

15.0.1 CLASSIFICATION OF TRANSIENTS AND ACCIDENTS

15.0.1.1 Categorization Matrix

This chapter is structured around an eight by five, event type/frequency matrix which, "categorize(s) the initiating events by type and expected frequency of occurrence so that only the limiting cases in each group (matrix element) need to be quantitatively analyzed."[1] Organization of this chapter around such a type/frequency matrix, "permits(s) the consistent application of specific acceptance criteria for each postulated initiating event."[1]

Each postulated initiating event is assigned to one of eight categories defined in Subsection 15.0.1.2. Each event within the eight major event types is also assigned to one of five frequency groups defined in Subsection 15.0.1.3. The following sections describe how each initiating event was assigned a position in the type/frequency matrix.

15.0.1.2 Event Types

Each postulated initiating event has been assigned to one of the following types:

a. Increased Heat Removal by Secondary System

b. Decreased Heat Removal by Secondary System

c. Decrease in Reactor Coolant Flow

d. Reactivity and Power Distribution Anomalies

e. Increase in Reactor Coolant System Inventory

f. Decrease in Reactor Coolant System Inventory*

g. Radioactive Release from a Subsystem or Component

h. Primary System Pressure Deviation

The assignment of an initiating event to one of these eight event types is made by collecting initiating events with the same major effect and similar occurrence rates into an Event Group. Each Event Group is then assigned to one of the above eight event types based on its primary impact on the NSSS. Table 15.0-1 lists all of the Event Groups and initiating events considered in the St Lucie Unit 2 accident analysis.

15.0.1.3 Frequency Groups

The five frequency groups used in the type/frequency matrix are listed below:

a. Moderate Frequency Event

A Moderate Frequency event may occur during a calendar year for a particular plant.

b. Infrequent Event

An Infrequent event may occur during the lifetime of a particular plant.

c. Limiting Fault

A Limiting Fault is not expected to occur during the lifetime of a particular plant. This broad frequency group is divided into three subgroups to allow comparison of events with similar frequencies. These three subgroups of Limiting Faults are consistent with the acceptance guideline divisions suggested by the Standard Review Plan[(2)] (See Subsection 15.0.1.7). The subgroups are defined below:

C.1 Limiting Fault - 1

A Limiting Fault - 1 event has a low probability of occurring during the lifetime for a particular plant.

*LOCA (Loss of Coolant Accidents) are addressed in Subsections 6.3.3 and 15.6.6.

C.2 Limiting Fault - 2

A Limiting Fault - 2 event has a very low probability of occurring in the lifetime for a particular plant.

C.3 Limiting Fault - 3

A Limiting Fault - 3 event has an exceedingly low probability of occurring in the lifetime for a particular plant.

15.0.1.4 Event Group Frequencies

The estimated frequency of occurrence of an Event Group is calculated from the sum of reported occurrences of the initiating events in that Event Group as observed in United States commercial PWR plants or from other non-nuclear related experience, i.e., high energy pipe break data. Conservative factors are applied to the estimated frequencies to determine a conservative upper bound frequency, referred to as the expected frequency of occurrence of an Event Group. (All initiating events in an Event Group are assumed to have the expected frequency of occurrence of the Event Group for the purpose of applying the acceptance guidelines.) The expected frequency serves as the basis for assigning each Event Group to one of the five frequency groups defined in Subsection 15.0.1.3. Table 15.0-2 shows all Event Groups positioned on the type/frequency matrix.

15.0.1.5 Event Combinations

Additional failures and/or special plant conditions are combined (via event tree analysis) with initiating events to generate event combinations. The frequency of and event combination is calculated by combining the expected frequency of an initiating event and the conditional probability of each additional failure or special plant condition. The resultant frequency serves as the basis for assigning event combinations to one of the five frequency groups defined in Subsection 15.0.1.3.

Additional failures are divided into the following four groups:

a. High-probability dependent occurrences

b. Low-probability dependent occurrences

c. High-probability independent occurrences

d. Low-probability independent occurrences

A dependent occurrence is an action which occurs as a direct result of an initiating event. All high probability dependent occurrences (e.g., turbine trip on reactor trip) are assigned a probability of one and are included in the definition of the initiating event.

An independent occurrence is a random, pre-existing failure, i.e., a failure which has occurred some time before an initiating event. The impact of this failure is not apparent until an initiating event causes the system containing the failure to perform an action which cannot be performed correctly.

15.0.1.5.1 Low-Probability Dependent and High-Probability Independent Occurrences

One or more low-probability dependent and/or high-probability independent occurrences may be combined with an initiating event with a resulting change in frequency. The difference in frequency between the initiating event and its resulting event combinations may cause the combinations to be placed in a different frequency category. These occurrences include the following:

a. Loss of offsite power as a result of turbine trip (low-probability dependent)

b. Stuck CEA on reactor trip (high-probability independent)

c. Failure of one bus to achieve a fast-dead bus transfer from a unit auxiliary transformer to a startup transformer (high-probability independent)

d. High event generated iodine spike see Subsection 15.0.4.3.2 (low-probability dependent)

For the purpose of selecting events to be considered in this chapter, low-probability dependent occurrences were defined to be those with a probability less than ~0.8. High-probability independent occurrences were defined to be those with a probability less than ~0.8 and greater than ~0.005.

15.0.1.5.2 Low-Probability Independent Occurrences

One low-probability independent occurrence (LPI) is also considered in combination with an initiating event. Combining the probability of any LPI with the frequency of an initiating event would usually result in an event combination that is shifted more than one frequency group. For conservatism, an event combination which includes an LPI is shifted only to the next lower frequency group. For example, an LPI combined with an initiating event from a Limiting Fault - 1 Event Group produces a Limiting Fault - 2 event combination. The combination of more than one LPI and an initiating event essentially produces a combination that is outside the design basis, i.e., the combination frequency is less than 10^{-6}/year. Therefore, only one LPI is considered in the development of event combinations. Table 15.0-3 lists all LPIs considered in each event analysis.

15.0.1.5.3 Special Plant Conditions

Besides additional failures, special plant conditions are considered in the development of event combinations. Although many such conditions (e.g., steam generator inventory activity, and control system operating status) could be addressed in this manner, only two are considered herein. These are high, pre-existing iodine concentration in the Reactor Coolant System (RCS) and high, pre-existing steam generator tube leakage. Either or both of these conditions are considered in combination with each initiating event (see also Subsection 15.0.4.3).

The RCS iodine concentration is dependent upon the history of plant operation immediately preceding an event. A high iodine concentration may be the result of a recent plant maneuver or transient. The maximum, preexisting iodine concentration considered is the value that will be used to establish the Technical Specification limit for continuous operation.

The steam generator tube leakage rate is considered in each event analysis. The maximum, pre-existing tube leakage considered is the value that will be used to establish the Technical Specifications as the limit for continuous operation.

15.0.1.6 Limiting Event Analysis

Initiating events and event combinations in each matrix element are evaluated to determine which produces the limiting approach to each acceptance guideline. This evaluation includes selecting the limiting LPI from those listed in Table 15.0-3 when an LPI combination is in the matrix element. Initiating events and event combinations are treated equally in this evaluation. The limiting events are analyzed in detail. The results of this analysis are presented in the respective sections as listed in the Table of Contents for this chapter and summarized in Table 15.0-5a.

15.0.1.7 Acceptance Guidelines

In order to "permit the consistent application of specific acceptance criteria for each postulated initiating event,"[1] acceptance guidelines have been established for each frequency group in the event type/frequency matrix. These guidelines are presented in Table 15.0-4.

15.0.1.7.1 Offsite Dose

Acceptance guidelines on offsite radiation dose have been established based on 10CFR100[4] criteria. The offsite dose acceptance guidelines for Limiting Faults correspond to those suggested for accidents by the Standard Review Plans[2]. The guidelines as a function of frequency are specified in Table 15.0-4.

15.0.1.7.2 Reactor Coolant System Pressure

Acceptance guidelines on Reactor Coolant System (RCS) pressure are based on the RCS design limits (GDC 14 and 15). The RCS is designed according to ASME Code, Section III. The applicable stress limits as a function of frequency category are specified in Table 15.0-4. Events are evaluated with respect to the maximum Reactor Coolant System pressures corresponding to these acceptance guidelines on stresses.

15.0.1.7.3 Fuel Performance

Acceptance guidelines on fuel performance have been established so that a coolable core geometry is maintained. The guidelines as a function of frequency category are specified in Table 15.0-4 and discussed in Subsection 15.0.4.4.

15.0.1.7.4 Loss of Shutdown Margin

Acceptance guidelines on the total loss of shutdown margin have been established to measure the time available to prevent loss of shutdown margin with the Reactor Coolant System cold or cooling (GDC 26). For all events in the Reactivity and Power Distribution Anomaly event category which are initiated from Plant Operating Modes 2 through 5 the guideline used is: the shutdown margin shall not go to zero in less than 15 minutes following an unambiguous alarm. For the events in this same event category which are initiated from Operating Mode 6 (Refueling) shutdown margin shall not go to zero in less than 30 minutes following an unambiguous alarm.

15.0.1.8 Section Numbering

The events analyzed are presented in sections in accordance with Reference 1. The events are numbered as described in Table 15.0-5. Sections are titled according to the event category and to the frequency of the initiating event presented.

15.0.1.9 Justification of Accident Selection (NRC Question) Cycle 1

15.0.1.9.1 Question No. 440.9

All events analyzed in Chapter 15 are designed to challenge the capability of the protection and engineered safeguards systems to maintain the fuel, pressure, and radiological release within prescribed limits, dependent upon the event category. For each event analyzed in Chapter 15 with a concurrent single active failure, justify why the single active failure selected is considered the worst case with respect to challenging the fuel, pressure, and radiological release limits.

Response

Each event presented in the various sections of the Chapter 15 accident analysis is the most adverse for its event type, frequency group and particular acceptance criteria. The worst case single failure is not necessarily presented. However, where a single failure (low probability independent occurrence or other coincident occurrence) is not specifically presented, it is either less limiting than the event presented in its place, or produces only a minor approach to the acceptance criteria.

For each of the event types listed in Subsection 15.0.1.2, the events and event combinations in each frequency group are evaluated with respect to acceptance criteria. The results of this process are the selected events presented in Chapter 15, which are the limiting events or event combinations. Discussions of the assumed failures follow.

(15.1) Increased feedwater flow with a failure to achieve fast transfer of a 4.16 kV bus is the limiting event combination with respect to offsite dose in the infrequent category. Failure to achieve fast transfer of a 4.16 kV bus causes loss of condenser, necessitating the use of the atmospheric dump valves for plant cooldown. Since a decontamination factor (DF) of 10 is assumed for steam release through the atmospheric dump valves, while a DF of 100 is assumed for steam release to the condenser, this failure maximizes the calculated offsite dose.

Steam line break with failure to achieve fast transfer of a 6.9 kV bus is the limiting event combination with respect to fuel performance in the Limiting Fault 2 frequency category. Failure to achieve fast transfer of a 6.9 kV bus causes loss of power to two of the four reactor coolant pumps, resulting in a decrease of reactor coolant flow. Decreasing reactor coolant flow concurrent with increasing core power and heat flux maximizes the DNBR decrease during the event, and therefore, maximizes calculated fuel damage.

Steam line break with loss of offsite power is the limiting event combination with respect to fuel performance in the Limiting Fault 3 frequency category. Loss of offsite power causes loss of power to all four reactor coolant pumps, resulting in the maximum rate of decrease of reactor coolant flow due to any failure. As

discussed above for failure to achieve fast transfer of a 6.9 kV bus, decreasing reactor coolant flow during the event maximizes calculated fuel damage.

(15.A) For the larger steam line break (SLB) events presented in Subsection 15.1.6 the concern is the possibility of degradation in fuel performance during potential post-trip return to power. Pre-trip fuel degradation for SLB events is addressed in Section 15.1. (See Subsection 15.1.5.3.5). Radiological releases for SLB events are bounded by the LF-3 event to be presented in Subsection 15.1.5.1. There is no approach to the 110 percent of design pressure criterion during SLB events.

Of the possible single active component failures for the St. Lucie 2 Plant, only two can impact the potential for post-trip return to power and consequent possible degradation in fuel performance: (a) failure of a main steam isolation valve to close on actuation of a main steam isolation signal (MSIV failure) and (b) failure of one high pressure safety injection (HPSI) pump or failure of one HPSI pump and one low pressure safety injection (LPSI) pump (the latter case being possible only if offsite power is unavailable). The only significant impact these single failures can have is on potential post-trip degradation in fuel performance. Table 15.0-11 shows the maximum post-trip reactivities, core average powers, and core average heat fluxes with an assumed MSIV failure and with an assumed HPSI pump or HPSI pump plus LPSI pump failure, as appropriate, for 6.36 ft^2 SLBs. Cases are presented for SLBs initiated at full power and at zero power, with and without loss of offsite power.

For cases with loss of offsite power, failure of one HPSI pump plus one LPSI pump is seen to present the greatest potential for post-trip degradation in fuel performance. Therefore this was the single failure assumed for the cases with loss of offsite power which are presented in Subsection 15.1.6.

For cases with offsite power available (no reactor coolant pump trip) the impact of the two possible single failures is nearly identical. The analyses presented in Subsection 15.1.6 assumed a MSIV failure for cases with offsite power available since this failure yields slightly higher core average heat fluxes. No conclusions would be changed by assuming, instead, one HPSI pump failure for these cases.

(15.2.2.1) The single failure selection for the isolation of turbine (IOT) in Subsection 15.2.2.1 is based on maximizing the radiological dose consequences. In the absence of fuel failures, as discussed in Subsection 15.2.2.2.4, the offsite dose is a function of the steam released from the steam generators and the decontamination factor (DF) associated the steam release. DFs of 100, 10 and 1 are associated with steam releases from the steam generators via the condenser, via main steam safety valves (MSSV) or atmospheric dump valves (ADV), and via MSSVs or ADVs when steam generator dry out occurs, respectively.

The limiting single failure is one which maximizes steam releases via the MSSVs or ADVs, and if possible, results in dry out of a steam generator. The MSSV failure was selected on this basis. The failure of a MSSV to reclose after opening is the only single failure which could force one steam generator to dry out, thereby releasing all radioactivity initially in the generator plus activity associated with steam generator tube leakage.

(15.2.2.2) The single failure selection for the Loss of Condenser Vacuum (LOCV) event in Subsection 15.2.3.2 is based on maximizing RCS pressurization. Maximum RCS pressurization for the LOCV event is determined by the rate of RCS heatup due to decreases in the heat transfer rate to the steam generators. Steam generator heat transfer is a function of steam generator secondary side temperature which is maintained by steam and feedwater flow, and is a function of the overall heat transfer coefficient between the reactor coolant and the steam generator fluid which is partially a function of the reactor coolant flow rate. LOCV is assumed to instantaneously terminate steam flow and feedwater flow. With steam and feedwater flow terminated, further reduction in the heat transfer rate to the steam generators can only result from a decrease in the RCS-to-steam generator heat transfer coefficient via a reactor coolant flow reduction. Of the two possible single failures (EFT and LOP), LOP produces the greatest reduction in coolant flow. Therefore, LOP is the limiting single failure and is presented in FSAR Subsection 15.2.3.2.

(15.3) For the loss of forced reactor coolant flow transients, the major parameter of concern is the minimum hot channel DNBR, as it establishes whether a fuel design limit has been violated, in which case fuel damage might be anticipated. Those factors which cause a decrease in local DNBR are:

a. increasing coolant temperature.

b. decreasing coolant pressure.

c. increasing local heat flux (including radial and axial peak effects as well as, average power increases)

d. decreasing coolant flow.

For the one pump resistance to forced flow (shaft seizure) with a loss of offsite power as a result of turbine trip event, the minimum DNBR occurs during the first two to four seconds of the transient, and the reactor is tripped by the pressure drop across the steam generators resulting from low reactor coolant system flow. Therefore, any single failure which would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first two to four seconds of the event.

The single failures that have been postulated are listed in Table 15.0-3. Most of these failures affect the secondary system, and during the first two to four seconds they do not affect the primary system parameters which determine the DNB ratio. The only failures which could affect those parameters during this interval are (1) a loss of normal ac, (2) a failure of the pressurizer level control system, (3) a failure of the pressurizer pressure control system and, (4) a failure of the reactor regulating system. The loss of normal ac power is already assumed for this analysis and results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control system, the reactor regulating system, and the feedwater control system.

Loss of function of the condensate and circulating water pumps and the feedwater control system initially affect only the secondary system and, thus, do

not effect DNBR in the first 2-4 seconds of the transient. Loss of power to the reactor regulating system and pressurizer level and pressure control systems renders those systems inoperable. This inoperability will have no significant impact on DNBR during the first two to four seconds. Loss of the reactor coolant pumps is the only significant consequence with regard to DNBR which results from a loss of ac.

Failure of the pressurizer level control, pressure control, or reactor regulating system prior to their becoming inoperable on loss of offsite power only insignificantly affect any of the four factors which determine DNBR during the first two to four seconds of the event. Thus, none of the single failures listed in Table 15.0-2 will result in a more adverse transient minimum DNBR than that predicted for the one pump resistance to forced flow (shaft seizure) with loss of offsite power as a result of turbine trip presented in Subsection 15.3.4.3.

(15.4) For reactivity and power distribution anomalies, the major parameter of concern is the minimum hot channel DNBR. This parameter establishes whether a fuel design limit has been violated, and thus whether fuel damage might be anticipated. Those factors which cause a decrease in local DNBR are:

a. increasing coolant temperature

b. decreasing coolant pressure

c. increasing local heat flux (including radial and axial power distribution effects)

d. decreasing coolant flow

An illustration will be presented as to why the uncontrolled positive reactivity insertion (UPRI) was analyzed with the loss of offsite power. The specific UPRI limiting event is the part length group drop. The part length group drop caused a reactor trip and thus the minimum DNBR occurs in the first two to five seconds. Therefore, any single failure which would result in a lower DNBR during the transient would have to affect at least one of the parameters during the first two to five seconds of the event.

The single failures that have been postulated are listed in Table 15.0-3. Most of these failures affect the secondary system, and during the first two to five seconds they do not affect the primary system parameters which determine the DNB ratio. The failures which affect the RCS behavior during this interval are (1) a loss of normal ac, (2) a failure of the pressurizer level control system, (3) a failure of the pressurizer pressure control system and, (4) a failure of the reactor regulating system. The loss of normal ac power, which is assumed, results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control system, the reactor regulating system, and the feedwater control system.

Loss of function of the condensate and circulating water pumps and the feedwater control system initially affect only the secondary system and, thus, do not affect DNBR in the first two to five seconds of the transient. Loss of power to the reactor regulating system and pressurizer level and pressure control systems renders those systems inoperable. This inoperability will have no significant

impact on DNBR during the first two to five seconds. Loss of power to the reactor coolant pumps is the only significant failure with regard to DNBR which results from a loss of ac.

Failure of the pressurizer level control, pressure control, or reactor regulating system cannot appreciably affect any of the four factors which determine DNBR during the first two to five seconds of the event. Thus, none of the single failures listed in Table 15.0-1 will result in a more adverse transient minimum DNBR than that predicted for the uncontrolled positive reactivity insertion with loss of offsite power as a result of turbine trip presented in Subsection 15.4.4.3.

(15.4.4.2) For the transients affecting RCS pressure, the major factors which lead to an increase in RCS pressure are:

a. increasing coolant temperature.

b. decreasing core flow.

c. decreasing primary to secondary heat transfer.

The CEA withdrawal caused a reactor trip on high reactor power with pressurizer pressure increasing, thus the maximum RCS pressure occurs in the first two to five seconds. Therefore, any single failure which would result in a higher RCS pressure during the transient would have to affect at least one of the above parameters during the first two to five seconds of the event.

The single failures that have been postulated are listed in Table 15.0-3. The failures which affect RCS behavior during this interval are (1) loss of normal ac, (2) failure of the pressurizer pressure control system (3) failure of the steam bypass control system, (4) failure of the reactor regulating system and (5) failure of the feedwater control system. The loss of normal ac power results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control systems, the reactor regulating system, the feedwater control system, and the steam bypass control system.

The effect of losing normal ac power on the CEA withdrawal is as follows: Loss of the reactor regulating system will have no appreciable affect on the transient in the first five seconds after trip. Loss of the steam bypass control system and feedwater control system results in a rapid buildup in secondary pressure and temperature. This reduces primary to secondary heat transfer and a further decrease in heat transfer is experienced as the reactor coolant pumps coast down. The resulting RCS pressure increase is further aggravated as the pressurizer sprays are not available due to loss of power to the reactor coolant pumps and pressurizer pressure control system.

An individual loss of one of the control systems is bounded by the assumption of the loss of normal ac power with respect to RCS pressure increase. Thus, none of the single failures listed in Table 15.0-3 will result in a higher RCS pressure than that predicted for a CEA withdrawal with a loss of offsite power as a result of turbine trip presented in Subsection 15.4.4.2.

(15.6) For the steam generator tube rupture (SGTR) event presented in Subsection 15.6.2 of the FSAR, the major concern is with regard to offsite accident doses. The offsite dose is dependent on the source of activity, the integrated primary to secondary leak, and the steam releases at the secondary side. None of the single failures considered would degrade the SGTR consequences enough to damage fuel and; thereby increase the source of activity. Therefore, only those single failures which result in an increase in the integrated leak and/or the steam releases will have an adverse impact on the offsite doses. In the St. Lucie Unit 2 FSAR, the SGTR event is classified as an infrequent event. The evaluation of this initiating event with a single failure shifts the category of this transient to a limiting fault. The event which is most limiting in the limiting fault category is the letdown line break (15.6.5) event.

The single failures that have been postulated are listed in Table 15.0-3 of the FSAR. Most of these failures will not adversely impact the calculated offsite doses due to: (1) assumption of manual mode of operation for SGTR event specific system (e.g., unavailability of steam dump and bypass system), (2) failure in a system resulting in an earlier reactor trip, thereby, reducing the integrated primary to secondary leak (e.g., pressurizer level and pressure control systems malfunction when in automatic), (3) failure in a system resulting in a reduction in the primary to secondary integrated leak by enhancing the RCS overcooling (e.g., feedwater regulating system failure due to one main feedwater control valve failing to close), and (4) failure under consideration not being applicable to depressurization events (e.g., pressurizer safety and relief valves failure to close upon opening).

For a fixed break size, the factors which would cause an increase in the integrated primary to secondary leak are: (a) increasing RCS pressure, (b) decreasing steam generator pressure, and (c) increased full power operating time before reactor trip. Only one of the single failures listed in Table 15.0-3 does not fall in the categories cited above and does impact the integrated leak. This failure is the closure of the letdown flow control valve to the zero flow position in response to a low level error signal. However, this failure has negligible impact on the total primary to secondary leak since the FSAR analysis for the SGTR event already assumes that the letdown flow reduces to a small minimum value on a low pressurizer level error signal.

The failures which could potentially affect the steam releases for the SGTR event are: (a) one main steam safety valve (MSSV) failing to reseat and (b) one atmospheric dump valve (ADV) failing to reclose. For these two failures, the steam releases would increase due to the direct path available for the release even after the steam generator pressure decreases below the safety valve opening setpoint or far enough to warrant closure of the ADV.

The stuck open ADV will not significantly affect the radiological releases, since the operator can either manually isolate the valve or close it. The failure of one MSSV to reseat will affect the dose calculation due to the increased steam release through the valve. However, consideration of the SGTR event with a single failure such as the stuck open MSSV shifts the event category from an infrequent one to a limiting fault category. In this category, the letdown line break outside containment (upstream of the control valve) is more limiting than the

SGTR event with a single failure as far as offsite accident doses are concerned because, the letdown line break releases 77,989 lbs. of reactor coolant directly to the environment with a DF of 1.0, while the SGTR transient releases 54,584 lbs. of reactor coolant to the affected steam generators which is subject to a DF of 10 before being released through the stuck MSSV.

The impact of the single failures of Table 15.0-3 on letdown relief valve opening (15.6-3), letdown relief valve opening with a pre-existing iodine concentration (15-6.4), and the letdown line break (upstream of the control valve, 15.6.5) events is provided in Subsection 15.6.6.1-4.

15.0.1.10 Non-LOCA Safety Analysis

15.0.1.10.1 Cycle 2

15.0.1.10.1.1 Introduction

This section presents the results of the Florida Power and Light, St. Lucie Unit 2, cycle 2 Non-LOCA safety analyses.

The Design Bases Events (DBES) considered in the safety analyses are listed in Table 15.0-12. These events are categorized into two groups: Moderate Frequency events (referred to herein as Anticipated Operational Occurrences, A00s) and Postulated Accidents. The DBEs were evaluated with respect to four criteria: Offsite Dose, Reactor Coolant System Pressure, Fuel Performance and Loss of Shutdown Margin. Tables 15.0-13, 15.0-14, 15.0-15 and 15.0-16 present the list of events analyzed for each criterion. All events were reanalyzed or re-evaluated to assure that they meet their respective criterion. The DBEs chosen for analysis for each criterion are the limiting events with respect to that criterion. The CVCS Malfunction event (Subsection 15.5.3.2.2) was analyzed to ensure that the operator has sufficient time to terminate the event before the pressurizer fills solid.

15.0.1.10.1.1.1 Methods of Analysis

Table 15.0-13 presents the events which were analyzed with respect to the offsite dose criterion. The methodology used is consistent with Cycle 1 analysis methods. For those cases where reported doses include pre-existing and/or accident generated iodine spiking, analyses methods are consistent with those of Reference 11.

A00s are analyzed to assure that Specified Acceptable Fuel Design Limits (SAFDLs) on Departure from Nucleate Boiling (DNB) and Fuel Centerline to Melt (CTM) limits are not exceeded. The methodology used by Combustion Engineering integrates Transient analysis results with the calculation of Limiting Safety System Settings (LSSS) and Limiting Conditions for Operation (LCOs). This methodology is described in Reference 17 A00s are divided into two categories (Table 15.0-15):

a. Design Basis Events Requiring RPS trips to assure that SAFDLs are not exceeded.

b. Design Basis Events for which RPS trips and/or Sufficient Initial Steady State Margin (preserved by the LCOs) are necessary to prevent exceeding the SAFDLS.

Transient analysis for the first category determine the values of parameters used as input to the LSSS calculation (e.g., the pressure bias and the transient power decalibration term are calculated for DBEs in this category and the limiting values of these parameters are used as input to the Thermal Margin/Low Pressure (TM/LP) trip calculator).

Transient analysis for DBEs in the second category determine the values of parameters used as input to the LSSS and/or LCO calculations (e.g., Required Overpower Margin (ROPM).

Transient analysis of the events in the latter category were performed utilizing the Statistical Combination of Uncertainties (SCU) methodology (Reference 18).

15.0.1.10.1.1.2 Mathematical Models

Plant response for Non-LOCA Events was simulated using the CDSEC computer code. The STRIKIN II computer code (Reference 6) was also used in the analyses of the Loss of Flow Event and the CEA Ejection Event.

Simulation of the fluid conditions within the hot channel of the reactor core and prediction of DNB was performed using the CETOP-D computer code (Section 4.4 and References 19 and 20).

Determination of DNBR for the post trip return to power portion of the steam piping failure events are based on the correlation developed by R. M. McBeth (Reference 21). Correction developed by Lee (Reference 22) are employed in order to use the McBeth correlation (for rod bundles) to predict burnout as a function of axial height, accounting for non-uniform axial heat flux. This methodology is consistent with that employed in the Cycle 1 analysis.

15.0.1.10.1.1.3 Input Parameters and Analysis Assumptions

Table 15.0-17 presents the key parameters assumed in the Cycle 2 transient analysis and compares them to the values used in Cycle 1. Specific initial conditions for each event are tabulated in that event's section. Most events were reanalyzed to determine the effect of changes to key parameters. Significant input changes from Cycle 1 to Cycle 2 include an increase in rated core power, increases in radial peaks and a lower assumed Technical Specification minimum allowed value for reactor coolant flow.

Table 15.0-18 presents the Reactor Protection Systems (RPS) and Engineering Safety Features Actuation System (ESFAS) Instrumentation analysis trip setpoints and delay times. In most cases, the values in the table include uncertainties which are consecutively selected to be larger than those calculated. Section 13.7 presents the response times of Reactor Protective Instrumentation and Engineered Safety Features.

Table 15.0-19 presents the key parameters assumed for the dose calculations.

15.0.2 ASSUMED PROTECTION SYSTEM ACTIONS

During the course of any event, various systems are called upon to function. Such systems are described in Chapters 5, 6, 7, and 9. The manner in which these systems function during events is discussed in each event description in the Sequence of Events and Systems Operation subsections. Subsection 15.0.2.1 gives a description of the Sequence of Events Analysis performed for each event for which a complete set of quantitative results is provided.

Subsection 15.0.2.2 describes the protection system setpoints and delay times assumed in the analyses presented in this chapter. Subsection 15.0.2.3 reviews the status of control systems assumed in the transient analysis.

15.0.2.1 Sequence of Events Analyses

The purpose of the Sequence of Events and Systems Operation subsection provided for each limiting event in this chapter is to identify:

a. "The step-by-step sequence of events from event initiation to the final stabilized condition,

b. The extent to which normally operating plant instrumentation and controls are assumed to function,

c. The extent to which plant and reactor protection systems are required to function,

d. The credit taken for the functioning of normally operating plant systems, (and)

e. The operation of engineered safety systems that is required."[1]

The results of these types of analyses can be used to demonstrate that the safety actions required to mitigate the consequences of an event are provided by the safety systems essential to performing each safety action. A sample of the format used here is described in Reference 5.

A sequence of events analysis (SEA) is performed for each limiting event for which detailed results are presented in this chapter. A SEA is omitted for those events which do not result in the actuation of safety systems or for which a detailed, quantitative analysis was not presented. The results of each analysis is presented in the sequence of events and systems operation subsection. The first table in each sequence of events and systems operation subsection (15.W.X.Y-1) presents a chronological list of events which occur during the transient and that time at which they occur, from the initiation of the event to the achievement of a final stabilized condition. This first table also provides an indication of the success path(s) (see below) on which each action is found. The second table (15.W.X.Y-2) is a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient. The results of the sequence of events analysis are summarized in the sequence of events diagram (SED) and in a third table (15.W.X.Y-3) which specified the reactor protection and engineered safety feature systems which were actuated to accomplish safety functions during the course of the transient.

The SED together with the chronological list of events and the sequence of events analysis symbol and acronym drawing (Table 15.0-6) may be used to trace the actuation and interaction of the systems used to mitigate the consequences of each event. The SED is a block diagram, composed of several success paths which define a set of actions leading from the initiating event to the accomplishment of a specific safety function. The safety functions used in the SEDs are defined in Table 15.0-6. A success path may be composed of two branches, one indicated by a solid line, describing the sequence of events which is assumed to occur in the transient analysis and the other, indicated by a dotted line, describing an alternative or back-up path to a given means of accomplishing a safety function. An alternative dotted path is specified if the analysis assumed the action of a non-safety system or of a non-redundant safety system in achieving a particular safety function. Nonsafety systems are indicated by an "NS" in the upper

righthand corner of the system block. The highlighted path demonstrates that a way to accomplish a safety function utilizing only safety systems is available.

The redundancy of a system or component is indicated by a fraction (e.g., 1/2, 2/4) placed beneath the system block. The numerator specifies the number of trains or components required to perform the action and the denominator specifies the number of trains or components available. The symbol "S.F." is used to indicate that no single active failure will prevent the accomplishment of the safety function.

Components or systems which require no active initiation or actuation to perform their function are considered to be passive and are marked as such with a "P" in the lower left-hand corner of the system block. The absence of a passive label implies that a component is considered to be active and must change state of perform its function.

Manual actuation of a given system or component is indicated by placing an "M" in the lower left-hand corner of the system block. When a manual actuation is required, the sensed variables necessary to perform the action are shown as inputs and the location of the signal is shown above the input signal circle.

The analysis setpoint values assumed in the transient analysis are noted along the success path. The assumed time delays or the time assumed to be required to perform an action are shown as a number with square brackets.

All sequence of events and systems operation subsections in this chapter demonstrate that after initiation of an event, it is possible to take the plant to the cold shutdown operating mode (as defined in the Technical Specifications) by means of the safety actions indicated. Not all events require that the plant be taken to cold shutdown.

15.0.2.1.1 Question No. 420.1 - Loss of Non-Class IE Instrumentation and Control Power System Bus During Power Operation(IE Bulletin 79-27)

If reactor controls and vital instruments derive power from common electrical distribution systems, the failure of such electrical distribution systems may result in an event requiring operator action concurrent with failure of important instrumentation upon which these operator actions should be based. This concern was addressed in IE Bulletin 79-27.

You are requested to address these issues by taking IE Bulletin 79-27 Actions 1 thru 3 under "Actions to be taken by Licensees" (a copy of 79-27 is provided in the attachment to this enclosure).

<u>Response</u>

Action Item 1

The buses identified in Tables 15.0-20 and 21 were reviewed and the buses presented in the second half of this response were determined to be the limiting items in their impact on achieving cold shutdown.

Safety-related instrumentation and controls are designed, as described in the first half of the response so that the impact of losing a bus or safety related instrumentation will not impact the ability to achieve cold shutdown.

Safety-related instrumentation and control systems conform to the criteria of IEEE-279-1971, "Criteria for Protection Systems for Nuclear Generating Stations". This means that the safety systems and instrumentation are designed for high functional reliability such that no single failure results in loss of the safety function and does not result in loss of the required minimum redundancy unless acceptable operation can be demonstrated. The safety systems are designed to assure that the effects of natural phenomena, normal operating maintenance, testing and postulated accident conditions do not result in loss of the safety function. The safety systems are separated from control systems to the extent that failure of any single control system component, power supply, or channel which is common to the control and safety system leaves intact a system satisfying the reliability redundancy, and independence requirements of a safety system.

The following identifies the non-safety related instrumentation and control systems and corresponding power supplies whose loss could affect the ability to achieve a cold shutdown condition. An evaluation of the effect of the loss of power supply on the ability to achieve a cold shutdown condition is also provided:

Power Panel 220 (120V AC)

Systems affected are:	Pressurizer Pressure Control System (PPCS)
	Reactor Regulating System (RRS)
	Boron Control System (BCS)
	Steam Bypass Control System (SBCS)
	Pressurizer Level Control System (PLCS)

Evaluation for achieving cold shutdown:

Due to the loss of power the RRS cannot move the CEAs, unless the operator switches the selector to the other channel which is still powered. Manual control of the rods is also available. Once the reactor is tripped the RRS will not impact achievement of cold shutdown. One channel of the PLCS will lose power, however the operator can switch to the other channel for level control. The charging pumps do not lose power (manual control available) and letdown is isolated (control valves close) should the operator not switch channels. The operator can conduct a plant cooldown and achieve the shutdown boron concentration in the RCS without letdown by balancing charging flow with volume shrinkage of the reactor coolant. The PPCS will also lose power but can be re-energized by switching the channel. Should the operator not switch channels, the pressurizer heaters can be manually operated and auxiliary sprays can be operated in place of the pressurizer sprays. Those systems can be used to achieve a cold shutdown condition. The impact to the BCS and SBCS will not impact achievement of cold shutdown. Reactor makeup water flow control will not be available, but boric acid flow control is available for achieving a cold shutdown boron concentration. Additionally, emergency boration can be implemented. Manual operation of the SBCS is available, or the

operator could choose to use the atmospheric dump valves to relieve secondary system pressure and temperature to shutdown cooling conditions.

Power Panel 221 (120V AC)

Systems affected are the same as those of power panel 220 (120V AC)

Evaluation for achieving cold shutdown:
The evaluation for power panel 220 (120V AC) applies with the following exceptions:

> The boric acid flow controller and volume control tank level (VCT) indication will not be available. Therefore the operator, by procedure, will emergency borate by directing to the charging pumps the boric acid flow, to achieve the cold shutdown boron concentration. Additionally both letdown control valves would fail closed and not be operable by either PLCS channel.

480V MCC 2A6 (non-essential portion)

Systems affected are the same as those of power panel 220 (120V AC)
Evaluation for achieving cold shutdown:
The evaluation for power panel 220 (120V AC) applies.

480V MCC 2B6 (non-essential portion)

Systems affected are the same as those of power panel 221 (120V AC)

Evaluation for achieving cold shutdown:
The evaluation for power panel 221 (120V AC) applies

Vital Panel 2A (120V AC)

The systems affected are:

Feedwater Regulating System (FWRS)

Steam Bypass Control System (SBCS)

Turbine Generator Control System (TGCS)

Evaluation for achieving cold shutdown:

Due to the loss of power, control power to one-half of the FWRS will be lost (one feedwater regulating valve and one bypass valve), the SBCS will not operate, but the turbine will runback in response to the reduced feedwater flow. A backup mechanism on vital panel 2B (120V AC) controls the runback. Should it not runback a reactor trip on low steam generator pressure would result. (It should be noted that the Turbine Runback feature has been deleted. Therefore, no automatic runback of the turbine will occur. The discussion in this paragraph is being retained, as is, for historical purposes.) Manual operation of the main or auxiliary feedwater and turbine bypass or atmospheric dump valves is available to control RCS heat removal during cooldown to cold shutdown conditions.

Vital Panel 2B (120V AC)

The systems affected are the same as those of vital panel 2A (120V AC).

Evaluation for achieving cold shutdown:

As in the evaluation of vital panel 2A (120V AC) one half of the FWRS will be disabled (control power lost to one regulating and bypass valve). Control power to the SBCS will be lost and the turbine runback backup mechanism will be without power. Manual operation of the main or auxiliary feedwater and atmospheric dump valves (SBCS control power completely lost) to control RCS heat removal during cooldown to cold shutdown conditions.

Vital Panel 2A and Vital Panel 2B (120V AC)

The systems affected are:

Feedwater Regulating Systems (FWRS)

Steam Bypass Control System (SBCS)

Turbine Generator Control System (TGCS)

Evaluation for achieving cold shutdown:

Control power will be lost to the FWRS and SBCS. A reactor trip on low steam generator level will result. Automatic actuation of auxiliary feedwater and opening of the main steam safety valves will stabilize secondary system pressure. The atmospheric dump valves and auxiliary feedwater will be used to control RCS heat removal to cold shutdown.

Bus 2AB (125V DC)

The systems affected are:

Reactor Regulating System (RRS)

Pressurizer Pressure Control System (PPCS)

Turbine Generator Control System (TGCS)

Evaluation on achieving cold shutdown:

The RRS would not control the CEAS. They would remain in the position they were in before the power loss and could be controlled through the CEDMCS by the operator or automatically tripped by the RPS if a trip signal occurs. The loss of power to the TCGS would not permit tripping of the turbine electronically. However the turbine could be tripped manually on a mechanical trip or could be isolated on a main steam isolation signal to close the main steam isolation valves. RCS pressure control would be maintained by the manual control of pressurizer heaters and auxiliary spray. RCS heat

removal to shutdown cooling could be controlled by auxiliary or main feedwater and SBCS or atmospheric dump valves. Additionally a manual transfer of loads to the startup transformers would be necessary after the turbine was tripped. If the manual transfer is not made the diesel generator will automatically start and supply emergency power.

Based on the evaluations discussed above no design modifications are required due to the effect of losing power to the buses identified in Tables 15.0-20 and 21.

Action Item 2

FP&L has prepared emergency procedures that will be used by control room operators, including procedures required to achieve a cold shutdown condition, upon loss of power to each class IE and non-class IE bus supplying power to safety and non-safety related instrument and control systems. The emergency procedures include the diagnostics/alarms/indicators/symptom resulting from the review and evaluation conducted per IE Bulletin No. 79-27 action item No. 1. The emergency procedures will describe the use of alternate indication and/or control circuits which may be powered from other non-class IE or class IE instrumentation and control buses. These procedures will also describe methods for restoring power to the bus. The emergency procedures that are developed for actions required during situations involving plant fires will also incorporate the above guidelines.

Action Item 3

The non-safety Vital Ac Power Supplies are fed from two Static Uninterruptible power supplies (SUPS). These are used to power non-safety instrumentation and control circuits, communication, security, fire detection and radiation monitoring systems. They are both rated 120V ± two percent ac, 60 Hz, single phase, 20 kVA and 30 kVA.

The 20 kVA SUPS is powered from MCC 2AB for the main feed and MCC 2AB for the bypass source. The dc is supplied from 125V dc bus 2AB. The 30 kVA SUPS is powered from MCC 2AB for the main feed and MCC 2C for the bypass supply. The dc is supplied from bus 2C. The bypasses for these SUPS are provided through a stepdown/regulating transformer. NOTE: In the current electrical configuration, the 20kVA SUPS dc supply is powered from the 2D 125V dc bus and the 30kVA dc supply is powered from the 2D 125V dc bus. This difference does not affect the conclusion of the evaluation. The discussion is maintained as-is for historical information only.

The SUPS are designed to provide power to their loads normally from the main feed through the rectifier/inverter. Failure of this main ac power feed will cause the SUPS to be powered from the battery.

The safety-related instruments for the Reactor Protective System and the Engineered Safety Features Actuation System are powered from four safety related inverters. The inverters are powered directly from the dc bus. Inverters 2A & 2C are powered from battery 2A and Inverters 2B & 2D are powered from battery 2B. Each inverter is provided with a maintenance bypass transformer. This must be manually switched usually during maintenance.

Circuitry is provided in the non-safety vital ac SUPS to shutdown the inverter portion and transfer to the alternate source, on one of the following conditions 1) Low inverter

voltage output, 2) High inverter voltage output and 3) Inverter output off frequency. The inverter will also transfer to the alternate source on an over current condition. Two timing relays are provided in this protective circuitry to prevent tripping the unit on spurious transients of the kind listed above. One timing relay delays the tripping of the unit and is set at approximately a 60 second delay. The other controls the transferring of the unit to the bypass source and is set at 10 seconds. If one of the above trouble conditions is sensed the timing relays start to time and at 10 seconds the unit will transfer to the alternate source. The other relay continues running for 60 seconds and then will shut the inverter down. This scheme is employed to allow transferring to the alternate source before the unit shuts down. All these malfunctions are alarmed.

The safety related instrument inverters are fed directly from the dc Bus. The inverters automatically shutdown on the following conditions 1) Low dc voltage input 2) High dc voltage input, 3) Low ac voltage inverter output. The inverter is designed to operate within the dc system voltage swing (105 to 140 dc). A timing relay is provided to prevent shutdown of the inverter on spurious transients of the kind listed above. This timing relay is set at 10 seconds. There is no automatic transfer to a bypass source on the safety instrument inverters.

The ac SUPS input is fed through a regulated rectifier. this allows the ac input voltage to vary and not affect the dc output. The regulator will allow the input ac voltage to vary -10 percent +10 percent and not effect SUPS operation.

Non-safety SUPS for SAS are provided similar to the plant vital ac SUPS (i.e., normal input is supplied through a regulated rectifier with battery supply available should ac power fail). AC input voltage range can vary from -15% to +10% and dc input range of 105-140V without effect to SUPS operation. Automatic transfer to the bypass source is provided. Transfer to the alternate source is initiated as above for the vital ac SUPS.

The same type units are employed on Unit 1 with successful operation.

Based on the re-review of IE Circular No. 79-02 and the evaluation discussed above, no design modifications are required.

15.0.2.2 Protection Systems Setpoints

This plant has two major protection actuation systems: the Reactor Protective System and the Engineered Safety Features Actuation System. The analysis setpoints used for both of these systems, to trip the reactor and to automatically actuate Engineered Safety Features, are described in this subsection.

The Reactor Protective System (RPS) is described in detail in Section 7.2. Table 15.0-7 lists the RPS trips which are assumed to function in the analyses discussed in this chapter, including the analysis setpoints, and trip delay times associated with each trip. The analyses take into consideration the response times of actuated devices after the trip setting is reached.

The delay times shown in Table 15.0-7 are defined as the elapsed time from when the sensor output reaches the analysis setpoints to when the reactor trip switchgear breakers open. The sensor response is modeled by using the transfer function for the particular sensor used. The interval between trip breaker opening and the time at which the magnetic flux of the control element assembly (CEA) holding coil has decayed enough to allow CEA motion is

conservatively assumed to be 0.74 seconds (changed from 0.34 seconds via amendment #38 to the Technical Specifications). Finally, a total value of 3.1 seconds (changed from 2.7 seconds via amendment #38 to the Technical Specifications) is assumed as the elapsed time from when electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90 percent insertion position.

The Engineered Safety Features Actuation System (ESFAS) is described in Section 7.3. The setpoints at which Engineered Safety Features are assumed to actuate are described in Table 15.0-8. The components or systems actuated during each event by the ESFAS signals are shown on the sequence of events diagrams.

15.0.2.3 Control System Operational Status

Some normally operating control systems are assumed to function during the course of the events described in this chapter. In general, automatic operation of these normally available control systems is assumed unless operation in the manual mode would make the approach to acceptance guidelines more limiting. In the manual mode, the control system is assumed to continue to function as it was prior to the event. For example, if the Steam Dump and Bypass Control System is in manual and is bypassing steam at time zero, then it will continue to bypass steam with the open bypass valve(s) staying in the same position. The assumed status of each control system is shown for each event in Table 15.W.X.Y-2.

The only system excepted from this practice is the Feedwater Regulating System (FWRS). Above 20 percent power, the plant is operated with the FWRS in automatic. This mode is therefore assumed for events analyzed in this chapter which start at this power or higher. For events starting at a lower power, either the FWRS is assumed to be in manual or the Auxiliary Feedwater System is assumed to be in operation.

The Feedwater Regulating System is not explicitly modeled in the current Safety Analyses. Feedwater flow is modeled to create a more adverse effect on the outcome of the event.

It is recognized that a control system may have a pre-existing failure which could cause it to function abnormally when in the automatic mode. If such a Low or High Probability Independent Occurrence is included in the definition of the event being considered (see Subsection 15.0.1), then the result of this additional failure is considered during the safety evaluation. Backup systems which will operate if a control system malfunctions are shown on the SED as alternative paths. A path utilizing only safety grade equipment is highlighted.

15.0.2.4 Auxiliary Feedwater System Actuation

Automatic Control of the Auxiliary Feedwater Actuation System (AFAS) incorporates a time delay. This time delay is described in Section 7.3.1.1.8.

The AFAS time delay used in the accident analyses is conservatively based on producing limiting results. Therefore, as an example, the AFAS time delay may be longer than the actual setpoint for a heat-up event to maximize pressure, whereas the AFAS time delay may be zero seconds for a cooldown event to maximize the cooldown and subsequent return to power.

15.0.2.5 Atmospheric Dump Valve Automatic Control

The safety analyses presented in this chapter assumed that the atmospheric dump valves (ADVs) were manually controlled by the operator; however, the plant design includes an automatic control system for the ADVs.

Subsection 15.1.3.1 summarizes the opening of a single ADV as an initiating event. Subsection 15.3.5.1.4 also considers the failure of a single ADV to close following automatic actuation during a reactor coolant pump seized shaft event with a loss of offsite power and technical specification steam generator tube leakage. The results of both these events meet the criteria for their frequency category.

15.0.2.6 Responses to NRC Questions (Cycle 1)

15.0.2.6.1 Question No. 420.3-Qualification of Control Systems (IE Information Notice 79-22)

Operating reactor licensees were informed by IE Information Notice 79-22, issued September 19, 1979, that certain non-safety grade or control equipment, if subjected to the adverse environment of a high energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade equipment. In the attachment to this Enclosure there is a copy of IE Information Notice 79-22, and reprinted copies of an August 30, 1979 Westinghouse letter and a September 10, 1979 Public Service Electric and Gas Company letter which addresses this matter.

Operating Reactor Licensees conducted reviews to determine whether such problems could exist at operating facilities.

We are concerned that a similar potential may exist at light water facilities now under construction. You are, therefore, requested to perform a review to determine what, if any, design changes or operator actions would be necessary to assure that high energy line breaks will not cause control system failures to complicate the event beyond your FSAR analysis. Provide the results of your reviews including all identified problems and the manner in which you have resolved them to NRC, by July 6, 1981.

The specific "scenarios" discussed in the above referenced Westinghouse letter are to be considered as examples of the kinds of interactions which might occur. Your review should include those scenarios, where applicable, but should not necessarily be limited to them. Applicants with other LWR designs should consider analogous interactions as relevant to their designs.

<u>Response:</u>

A review of potential control system interactions during high energy pipe breaks has been conducted for St. Lucie Unit 2. The review is based on the Combustion Engineering (CE) generic review effort (See Reference 16). The review considered both the specific systems listed in IE Information Notice 79-22 and other non-safety systems which could possibly interact with safety grade systems.

The results of a review of the CE generic evaluation applied to the St. Lucie Unit 2 design are presented below.

1. Steam Line Break With PORV Control System Failure

   This event assumes that the adverse environment created by a large steam line break inside containment causes the PORV to inadvertently open and remain open. RCS mass removal via the PORV is assumed to cause additional containment pressurization and additional void formation within the Reactor Coolant System.

   A review of the St. Lucie Unit 2 PORV control system has not identified a mechanism which could cause the PORV to inadvertently open and remain open. The signal to open the PORV comes from safety grade equipment (Reactor Protection System). Moreover, the PORVs are qualified for an environment in excess of 400F. Also, if power (dc) to the PORV control solenoid is lost, the PORV remains closed. Therefore, FP&L concludes that this event would not occur at St. Lucie Unit 2.

2. Steam Line Break With Feedwater Flow Control System Failure

   This event assumes a failure in a steam generator level instrument causing the FWRS to supply feedwater in excess of steam demand, thereby filling the affected steam generator and potentially leading to excessive moisture carryover. The St. Lucie Unit 2 design incorporates a design feature that automatically closes the feedwater regulating valves at the high steam generator level and trips the turbine, trips the main feedwater pumps, and closes the pump discharge valves at the high-high level (see Subsection 15.0.2.6) Question 420.45. The instrumentation transmitting the safety-grade signal is a four-channel system with portions qualified to withstand the adverse environment. Those portions not qualified will not be exposed to the adverse environment. FP&L therefore concludes that this event would not occur at St Lucie Unit 2.

3. Steam Line Break With Failure of Main Steam Paths Downstream of MSIV's

   This event assumes a steam line break inside containment with the MSIV on the unaffected steam generator failing to close. Additionally, downstream of the MSIV the main steam paths are assumed to fail open due to the adverse environment from the steam line break. The open main steam paths increase the RCS cooldown which adds positive reactivity to the core. This reactivity addition would then increase the potential for a post-trip return to power in the reactor core.

   The systems, one of which must fail in order to open a steam path downstream of the MSIV, are the Turbine Generator Control System (TGCS) and Steam Bypass Control System (SBCS). Review of the St. Lucie Unit 2 design shows that the TGCS and SBCS would not be exposed to the adverse environment. However, the T_{avg} input to the SBCS which is generated by the RRS could be exposed to the accident environment. This T_{avg} input, though, is used only to block initiation of a quick opening signal and cannot cause the SBCS valves to open. A quick opening signal would not be generated due to the low steam flow and low pressure. Also, the TGCS signals to close the turbine stop valves are generated by diverse and redundant means relative to the generation of a MSIS. Therefore, FP&L concludes that this event would not occur at St. Lucie Unit 2.

4. Steam Line Break With Atmospheric Dump Valve Control System Failure

   This event assumes a steam line break outside containment and upstream of the MSIV. The adverse environment caused by the steam line break is assumed to cause the atmospheric dump valve upstream of the MSIV in the unaffected steam generator to open and remain open.

   The postulated failure of an atmospheric dump valve could occur if the valve was in the automatic control mode and was impinged on by the steam jet. However, the two trestles are physically separated by distance and each is enclosed by a one inch steel wall as can be seen in Figure 10.4-14. See Subsection 3.8.4.1.9 for a discussion of the protection of components located in the trestle area. This shows that the atmospheric dump valve controls on one main steam line would not be affected by a break in the other main steam line. Therefore, FP&L believes that this event would not occur at St Lucie Unit 2.

5. Feed Line Break With RCS Inventory Control Failure

   This event assumes a feedwater line break inside containment with the adverse environment causing the pressurizer level indication to fail low, leading to an increase in RCS inventory. This is assumed to result in a liquid-filled pressurizer with liquid discharge out of the power operated relief valves and primary safety valves.

   St. Lucie Unit 2 has pressurizer level instruments which are post-LOCA qualified and a safety grade alarm on high pressurizer level is being installed. Therefore, FP&L believes that this event would not occur at St. Lucie Unit 2.

6. Feed Line Break With PORV Control Failure

   This event assumes that the adverse environment created by a feedwater line break inside containment causes the power operated relief valve (PORV) to open and remain open. RCS mass removal via the PORV is assumed to cause additional containment pressurization and void formation within the RCS.

   A review of the St. Lucie Unit 2 PORVs has not identified a mechanism which would cause the PORV to inadvertently open and remain open. The signal to open the PORV comes from safety grade equipment (Reactor Protection System). Moreover, the PORVs are qualified for an environment in excess of 400F. Also, if power (dc) to the PORV control solenoid is lost, the PORV remains closed. Therefore, FP&L concludes that this event would not occur at St. Lucie Unit 2.

7. Feed Line Break With Feedwater Control Failure

   This event assumes a failure in a steam generator level instrument causing the FWRS to supply feedwater in excess of steam demand, thereby filling the affected steam generator and potentially leading to excessive moisture carryover. The St. Lucie Unit 2 design incorporates a design feature that automatically closes the feedwater regulating valves at the high steam generator level and trips the turbine, trips the main feedwater pumps, and closes the pump discharge valves at the high-high level (see Subsection 15.0.2.6) Question 420.45. The instrumentation transmitting the safety-grade signal is a four-channel system with portions qualified

to withstand the adverse environment. Those portions not qualified will not be exposed to the adverse environment. Therefore, FP&L concludes that this event would not occur at St Lucie Unit 2.

8. Feed Line Break With Atmospheric Steam Dump Control Failure

   This event assumes that a feedwater line break occurs outside containment downstream of the check valve. The adverse environment is assumed to cause the atmospheric dump valves upstream of the MSIV in the unaffected steam generator to open and remain open. If the operator does not take action there would be the potential for dry-out and depressurization of both steam generators.

   The postulated failure of the atmospheric dump valves, located upstream of the main steam isolation valves, could occur if the valves were in the automatic mode during power operations. However, consistent with the analyses in the FSAR, this system is maintained in the manual mode during power operations. The Technical Specification specify in which modes of plant operation control of the atmospheric dump valves must be in manual. Therefore, FP&L concludes that this event would not occur at St. Lucie Unit 2.

9. CEA Position Malfunctions Due to Steam and Feedline Breaks CEA Ejection and Small Break LOCA

   These events assume a small high energy line break inside containment with the Reactor Regulating System (RRS) in the automatic mode. The adverse environment is assumed to cause a low indicated power level from the temperature input to the Reactor Regulating System (RRS) causing the CEAs to be withdrawn.

   Consistent with the analyses in the FSAR, the automatic rod withdrawal function of the RRS will be physically defeated by disconnecting the wires that send the auto-withdrawal signal from the RRS to the CEA drive mechanisms. Therefore, FP&L concludes that these events would not occur at St. Lucie Unit 2.

10. SIT Isolation Malfunction Resulting From Small Break LOCA

    This event assumes a small break LOCA inside containment with the adverse environment affecting the safety injection tank(s) (SIT) isolation function. It is assumed that the SITs are not isolable, resulting in the non-condensible nitrogen cover gas entering the RCS.

    St. Lucie Unit 2 has valves and instrumentation and control systems which are environmentally qualified to withstand the adverse environment. Backup means are also available to depressurize the SITs and thereby prevent non-condensible gases from entering the RCS. Therefore, FP&L concludes that this event would not occur at St. Lucie Unit 2.

Based on these results, no design changes are necessary to assure that high energy line breaks do not cause control system failures to complicate events beyond the FSAR analysis for St Lucie Unit 2.

15.0.2.6.2 Question No. 420.4 - Control System Failures

The analyses reported in Chapter 15 of the FSAR are intended to demonstrate the adequacy of safety systems in mitigating anticipated operational occurrences and accidents. Both Congress and ACRS have raised an issue in this area. Commissioner Ahearne has responded to Congress regarding this issue (Refer to attachment to this enclosure) and part of his response referred to control system reviews to be performed in connections with OL licensing.

Based on the conservative assumptions made in defining these Chapter 15 design-basis events and the detailed review of the analyses by the staff, it is likely that they adequately bound the consequences of single control system failures.

To provide assurance that the design basis event analyses adequately bound other more fundamental credible failures you are requested to provide the following information:

1. Identify those control systems whose failure or malfunction could seriously impact plant safety.

2. Indicate which, if any, of the control systems identified in (1) receive power from common power sources. The power sources considered should include all power sources whose failure or malfunction could lead to failure or malfunction of more than one control system and should extend to the effects of cascading power losses due to the failure of higher level distribution panels and load centers.

3. Indicate which, if any, of the control systems identified in (1) receive input signals from common sensors. The sensors considered should include, but should not necessarily be limited to common hydraulic headers or impulse lines feeding pressure, temperature, level or other signals to two or more control systems.

4. Provide justification that any simultaneous malfunctions of the control systems unidentified in (2) and (3) resulting from failures or malfunctions of the applicable common power source or sensor are bounded by the analyses in Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

<u>Response</u>

1. The control systems whose failure or malfunction may impact plant safety are shown below:

   Feedwater Regulating System

   Turbine-Generator Control System

   Steam Bypass Control System

   ADV Control System

   Boron Control System

Reactor Regulating System*

Control Element Drive Mechanism Control

Pressurizer Pressure Control System

Pressurizer Level Control System

Reactor Coolant Pumps

Power Operated Relief Valves

Steam Generator Blowdown System

Impact of Loss of Common Power Sources

2&4. The control systems identified in (1) that receive power from common power sources are identified below. The effect of losing the power sources and an evaluation of plant response are also provided. The results of this evaluation provide justification that any simultaneous malfunctions of control systems identified herein, resulting from common power supply malfunctions are bounded by the analysis of Chapter 15.

Loss of 120V ac from Power Panel 220

This power loss will impact the pressurizer level control system (PLCS), the pressurizer pressure control system (PPCS), the reactor regulating system (RRS), the boron control system (BCS), and the steam bypass control system (SBCS). Specifically, the PLCS will loge control power, assuming the selector switch is on that channel (it will be unaffected if on the other channel). The letdown control valve will go to its fail closed position and the charging pumps will remain powered, and available for manual control. The PPCS will lose control power, assuming the selector switch is on that channel. The pressurizer spray valve will go to its fail closed position and the pressurizer heaters will remain powered and available from manual control.

Additionally, the low-low level automatic cut-off of the pressurizer heaters will lose control power. The RRS will lose power assuming the selector switch is on that channel (it will be unaffected if on the other channel). The control element assemblies will remain in their position prior to the power loss. The BCS will not completely be lost. The reactor makeup water flow controller will lose power with the boric acid flow controller unaffected. The letdown line will be affected with the temperature elements for the regenerative and letdown heat exchangers losing power, however the letdown line will be isolated by the letdown control valves mentioned previously. The SBCS will not receive a T_{avg} input from the RRS which

*The response to Question 420.4 on this page and subsequent pages discusses the Reactor Regulating System (RRS). The response is accurate for the original design; however, the use of the RRS has changed. Automatic withdrawl of CEA's has been defeated, pressurizer pressure inputs to the RRS have been removed and operating procedures direct operation of the plant with the CEA mode selector switch in manual during power operations. The response will be maintained as-is for historical purposes.

may cause the turbine bypass valves to remain closed. Secondary pressure relief and RCS heat removal control can be accomplished through the main, steam safety valves and atmospheric dump valves.

Evaluation of Plant Response:

The loss of the PLCS, PPCS, RRS, BCS, and SBCS due to loss of 120V ac from power panel 220 will not seriously impact plant safety. The reactor could function for a time without operator action before a reactor trip would result (most likely on high pressurizer pressure). The operator can choose to select the other channel for correct operation of the PLCS, PPCS, and RRS. However manual control of the charging pumps, pressurizer heaters, auxiliary sprays, and turbine bypass valves is available. The operator will still have control of the boric acid flow to the charging pumps and he can choose to align the refueling water tank to charging if necessary.

The analysis of the CVCS malfunction, excess charging, in Subsection 15.5.3.2 bounds this scenario. The analysis in Subsection 15.5.3.2 assumes maximum charging rate for two pumps with letdown isolated. The operator is alerted to the event by a safety grade alarm on high pressurizer level and terminates the event prior to reaching a reactor trip setpoint.

Loss of 120V ac from Power Panel 221

This power loss will impact the pressurizer level control system (PLCS), the pressurizer pressure control system (PPCS) and the reactor regulating system (RRS), the boron control system (BCS), and the steam bypass control system (SBCS). Specifically, the same impact as with the loss of 120V ac from power panel 220 will occur with the following exceptions:

The reactor makeup water flow control will remain powered, however the boric acid flow controller will lose power. Additionally the temperature element on the letdown heat exchanger controlling the component cooling water control valve will lose power. The volume control tank level inputs to the BCS will lose power. Also the station alarms (annunciators) will transfer to 125V dc power. The letdown control valves will fail closed and will not be operable by either PLCs channel.

Evaluation of Plant Response:

There will be no serious impact to plant safety for the event presented above. In the absence of operator action the reactor would eventually trip (on high pressurizer pressure). However, the operator would be alerted to such an event due to erroneous pressurizer pressure level indications in the control room. He may choose to switch the redundant channel for correct operation of the PLCS, PPCS and RRS. However, manual control of the charging pumps, pressurizer heaters, and auxiliary sprays is available. The operator can also bypass the boric acid flow controller and provide borated water directly to the charging pumps or align the refueling water tank. The conclusion from the loss of 120V ac from power panel 220 apply to this scenario.

Loss of 480V MCC 2A6 (non-essential portion)

The impact of losing this motor control center (MCC) is similar to the loss of 120V ac from power panel 220, since power panel 220 receives power from this MCC.

Evaluation of Plant Response:

The plant response for loss of power panel 220 (120V ac) applies.

Loss of 480V MCC 2B6 (non-essential portion)

The impact of losing this MCC is similar to the loss of 120V ac from power panel 221, since power panel 221 receives its power from this MCC.

Evaluation of Plant Response:

The plant response for loss of power panel 221 (120V ac) applies.

Loss of 120V ac Vital Panel 2A * See page 15.0-30

This loss of power will impact the feedwater regulating system (FWRS), steam bypass control system (SBCS) and the turbine generator control system (TGCS). Specifically, in the FWRS control power to one regulating valve and bypass valve will be lost. Additionally, main steam flow input to the SBCS from the FWRS is not transmitted from one channel. The turbine runback mechanism will be without power.

Evaluation of Plant Response:

The feedwater regulating system will still control one regulating and bypass valve. The loss of the turbine runback function is backed up by instrumentation of 120V ac vital Panel 2B which will runback the turbine in response to the decreased feedwater flow. Should the runback not operate properly, a reactor trip may result on low steam generator pressure. Manual operation of the atmospheric dump valves and auxiliary feedwater is available. Should the SBCS operate properly or reactor trip not occur the plant would stabilize at a decreased power condition.

The Isolation of Turbine event in Subsection 15.2.1.2 bounds this scenario. The analysis in Subsection 15.2.1.2 assumes a turbine trip followed by a ramp back of both feedwater trains to 5% flow and takes no credit for steam bypass to condenser. This results in a greater primary to secondary heat removal imbalance, and therefore higher RCS pressure. Taking no credit for the steam bypass to condenser maximizes radiological consequences. The scenario for loss of 120V ac vital panel 2A does not result in any degradation of the fuel performance.

120V ac Vital Panel 2B*

This loss of power will impact the feedwater regulating system (FWRS), steam bypass control system (SBCS), and the turbine generator control system (TGCS). Specifically, in the FWRS control power to one regulating valve and one bypass valve will be lost. Additionally, control of the SBCS would be lost. The TGCS would remain functional, but would suffer a loss of the backup to the turbine runback function.

Evaluation of Plant Response:

The FWRS will still control one regulating and one bypass valve. The SBCS will be without control power and the turbine would runback in response to decreased feedwater flow. Should it not runback a reactor trip may result on low steam generator pressure. The auxiliary feedwater and atmospheric dump valves are available for RCS heat removal. Should a reactor trip not be generated a new steady state at a decreased power level would occur. The conclusions for loss of 120V ac vital panel 2A apply to this scenario.

Loss of 120V ac Vital Panels 2A and 2Bb*

This power loss will impact the FWRS, SBCS, and TGCS. Specifically, feedwater and steam bypass control would be lost and the turbine runback mechanism would lose power.

Evaluation of Plant Response:

A reactor trip on low steam generator level will result. Automatic actuation of auxiliary feedwater and opening of the main steam safety valves will relieve secondary system pressure. The atmospheric dump valves and auxiliary feedwater will be used to control RCS heat removal.

The analysis of the Loss of Condenser Vacuum in Subsection 15.2.2.2 bounds this scenario. The analysis in Subsection 15.2.2.2 assumes a loss of feedwater flow and unavailability of the SBCS on turbine trip. This requires auxiliary feedwater and the use of main steam safety or atmospheric dump valves. This maximizes the RCS pressure increase and radiological consequences.

Loss of 125V dc Bus 2AB

This power loss will impact the RRS, the PPCS and the TGCS. Specifically, control of the RRS and PPCS, both channels, would be disabled. The turbine trip solenoids and generator under frequency lockout relays would be without power (failed closed). NOTE: Current configuration does not have the turbine trip or generator under frequency on this bus. However, this difference would not effect the conclusion of the following evaluation. The discussion is maintained as-is for historical information.

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*The Turbine Runback feature has been deleted. However, this section is in response to NRC Questions and is being maintained, as is, for historical purposes.

Evaluation of Plant Response:

The CEAs would remain in the position they were in before the power loss and could be controlled through the CEDMCS by the operator. Without the PPCS, pressure control would be maintained by manual control of the charging pumps and letdown and auxiliary spray. Should a reactor trip result, the turbine would not trip electrically but would be tripped manually. If required the main steam isolation valves would close isolating the turbine and maintaining RCS heat removal functions. Additionally a manual transfer of loads to the startup transformers would be necessary after the turbine was tripped.

The loss of offsite power analysis in Subsection 15.3.2.2 bounds this scenario. The loss of offsite power results in a simultaneous loss of feedwater, loss of primary coolant flow and disables the PPCS, PLCS, SBCS and FWRS. Therefore, the peak RCS pressure and radiological consequences are more severe. For the loss of 125V dc Bus 2 AB, there is no fuel damage.

3&4. Impact of Failure in Common Sensors

The control systems identified in (1) that receive input signals from common sensors are identified below. Descriptions of the effect of the malfunctions on the control systems and an evaluation of plant response and backup system availability are also provided. The results of this evaluation provide justification that any simultaneous malfunctions of control systems identified herein, resulting from common sensor malfunctions are bounded by the analyses of Chapter 15.

Malfunctions of Pressurizer Pressure Signal (fails low) to the RRS and PPCS

If malfunction causes a low pressurizer pressure signal to be transmitted, the pressurizer heaters would turn on and the pressurizer sprays would shutoff.

Evaluation of Plant Response:

The reactor would eventually trip on high pressurizer pressure if the operator did not take action. The operator could de-energize the heaters manually and control pressure with the charging and letdown systems and auxiliary sprays. Should the reactor not trip, because the appropriate trip setpoints were not reached by the affected parameters (pressure and power), a new steady state would be reached. Operator action could maintain power operation until the sensor could be repaired.

The scenario described above to bounded by the Isolation of Turbine event in Subsection 15.2.1.2. The analysis in Subsection 15.2.1.2 assumes a turbine trip followed by a ramp back of both feedwater trains to 5 percent flow and no credit for the SBCS. This causes greater primary to secondary heat removal imbalance, and a higher RCS pressure than the above scenario. For the pressurizer pressure signal failing low, there are not event related offsite doses or fuel damage.

Malfunction of Pressurizer Pressure Signal (fails high) to the RRS and PPCS

If the malfunction causes a high pressurizer signal to be transmitted, the pressurizer sprays would come on and the pressurizer heaters would be de-energized. The RRS

would adjust the rods in response to the high pressure signal thereby decreasing reactor power.

Evaluation of Plant Response:

The reactor would trip on the thermal margin low pressurizer pressure (TMLP), and a SIAS may result. The operator could close the spray valves and use the charging and letdown systems and auxiliary spray to control pressure. Should the reactor not trip due to affected parameters not reaching the trip setpoints, a new steady state would be reached. Operator action could maintain power operation until the sensor could be repaired.

For the calculation of the setpoints for the TM/LP trip, this transient and other more limiting transients, such as the inadvertent opening of a PORV, are considered. Therefore, a reactor trip would occur so that no fuel pins would experience a DNBR less than 1.19 (using CE-1 critical heat flux correlation). Also, there would not be any event related offsite doses since there is no fuel failure or release of primary fluid to the atmosphere.

Malfunction of Pressurizer Level Signal (fails low) to the PLCS and PPCS

If malfunction causes a low pressurizer level signal to be transmitted, the charging flow would increase and letdown flow would decrease. The pressurizer heaters would be de-energized if a low enough signal was transmitted.

Evaluation of Plant Response:

Increasing pressurizer level would be identified by the operator on level indication and a safety grade alarm in the control room. Manual control of the charging and letdown systems could prevent the overfilling of the pressurizer and preclude a reactor trip on high pressurizer pressure. This event is bounded by the excess charging event in Subsection 15.5.3.2.

Malfunction of Pressurizer Level Signal (fails high) to the PLCS and PPCS

If malfunction causes a high pressurizer level signal to be transmitted, the charging flow would decrease and letdown increase.

Evaluation of Plant Response:

A decreasing pressurizer level may lead to a possible reactor trip on low pressure and SIAS if the operator does not intervene. The SIAS would isolate letdown and charging would be available to restore pressurizer level. Operator could avert a reactor trip and SIAS through manual control of charging and letdown based on level indication in control room. Additionally the pressurizer heaters would remain on until the low-low pressurizer level is reached prolonging the time to reactor trip.

The reactor trip on low pressurizer pressure would prevent any fuel pins from failing. There would not be any event related offsite doses since there is no fuel failure or release of any primary system fluid. The analysis of the opening of a letdown relief valve in Subsection 15.6.3.1 bounds the above scenario.

Malfunction of First Stage Turbine Pressure Signal (fails low) to the RRS

If the malfunction causes a low pressure signal to be transmitted the RRS will insert the CEAs if the CEA control is auto, to produce a T_{avg} commensurate with the low pressure signal. This T_{avg} output signal is transmitted to the SBCS affecting its operation.

Evaluation of Plant Response:

The reduced heat output from the RCS, due to the insertion of the regulating CEAs, reduces the steam flow to the turbine. The SBCS receives a low T_{avg} signal from the RRS so the valves will not open. A reactor trip would occur on low steam generator pressure with a possible MSIS. The main steam safety valves and atmospheric dump valves are available for controlling RCS heat removal.

The Isolation of Turbine event in Subsection 15.2.1.2 bounds this scenario because it has a more severe secondary side transient, which increases the primary to secondary heat removal imbalance. The results in a higher RCS pressure. The analysis in Subsection 15.2.1.2 does not credit the SBCS which maximizes radiological releases. For the malfunction of First Stage Turbine pressure signal (fails low), there is no fuel damage.

Malfunction of First Stage Turbine Pressure Signal (fails high) to the RRS

If the malfunction causes a high pressure signal to be transmitted, the RRS in the automatic mode would withdraw regulating CEAs to produce a T_{avg} commensurate with the high pressure signal.

Evaluation of Plant Response:

The automatic rod withdrawal function of the RRS will be physically defeated so that this event would not occur. The measures taken to defeat the automatic withdrawal will be essentially the same as those on St. Lucie Unit 1.

Note: The automatic rod withdrawl function was defeated as part of the original construction of Unit 2.

Malfunction of Main Steam Flow Signal (fails low) to the FWRS and SBCS

If the malfunction causes a low steam flow signal to be transmitted, the FWRS will reduce feedwater flow and the SBCS will not open the turbine bypass valves.

Evaluation of Plant Response:

The mismatch between feedwater flow and turbine demand would produce a reactor trip on low steam generator level. The auxiliary feedwater system and manual control of the SBCS or atmospheric dump valves is available to achieve a stabilized plant condition. The Isolation of Turbine event in Subsection 15.2.1.2 bounds this scenario, as it results in a more severe secondary side transient prior to reactor trip on high pressurizer pressure.

Malfunction of Main Steam Flow Signal (fails high) to the FWRS an SBCS

If the malfunction causes a high steam flow signal to be transmitted, the FWRS will increase feedwater flow (the SBCS will not open the turbine bypass valves).

Evaluation of Plant Response:

The steam generator level will increase. The operator could manually control the FWRS and SBCS based on steam generator level and pressure indications in the control room. Should the operator not take action a high steam generator level signal would close the feedwater regulating valves and trip the turbine. A reactor trip on turbine trip would follow with actuation of auxiliary feedwater on steam generator low level signal. Auxiliary feedwater and manual operation of the SBCS or atmospheric dump valves provide a mechanism for RCS heat removal to stabilize the plant.

The increase in feedwater flow event in Subsection 15.1.2.1 bounds this scenario. The analysis in Subsection 15.1.2.1 assumes the maximum increase in feedwater flow due to a failure in the FWRS. This maximizes the increased heat removal aspects of the transient, and therefore results in a more adverse fuel performance transient. A turbine trip signal is generated on high steam generator level and no credit is taken for the SBCS so that steam is released through the main steam safety valves or ADVs.

Malfunction of RCS Average Temperature (T_{avg}) (fails low) to the RRS and PLCS

If the malfunction causes a low T_{avg} signal to be transmitted, the level setpoint program for the PLCS will be lower, resulting in a lower pressurizer level.

Evaluation of Plant Response:

Low pressurizer level alarms and indications will alert the operator to the level decrease. Manual control of charging and letdown will regain the appropriate pressurizer level.

Consistent with the analysis in the FSAR, the automatic rod withdrawal function of the RRS will be physically defeated by disconnecting the wires that sent the auto-withdrawal signal from the RRS to the CEA drive mechanisms.

Note: The automatic rod withdrawal function was defeated as part of the original construction of Unit 2.

This event is bounded by the analysis of the opening of a letdown relief valve in Subsection 15.6.3.1 which results in a more severe pressurizer level decrease.

Malfunction of RCS Average Temperature (T_{avg}) (fails high) to the RRS and PLCS

If the malfunction causes a high T_{avg} signal to be transmitted, the level setpoint program for the PLCS will be higher, resulting in a higher pressurizer level; the RRS is assumed to adjust the rods if the CEA control system is in auto, decreasing reactor power.

Evaluation of Plant Response:

Increasing pressurizer level would be identified by the operator based on level indication and a safety grade high level alarm in the control room. Manual control of the charging and letdown systems could prevent overfilling of the pressurizer and preclude a reactor trip on high pressurizer pressure. This event is bounded by the excess charging event in Subsection 15.5.3.2.

Impact of Failure of Common Instrument Line or Tap

Table 15.0-22 identifies the Common Line/Tap for protection channel and control channels (or multiple control channels) that are serving multiple channels. This table has been reviewed and those lines or taps which were determined to be limiting in their effect on plant response are identified below. The effect of losing protection channels due to a single failure on a common instrument line or tap, does not defeat required protection system redundancy. Therefore the effect of losing protection channels is not addressed here. Descriptions of the effects of the malfunctions on the control systems and an evaluation of plant response and backup system availability are also provided. The results of this evaluation provide justification that any simultaneous malfunctions of control systems identified herein, resulting from common instrument line or tap malfunctions are bounded by the analysis of Chapter 15.

Pressurizer Pressure Signal (PT-1100X) and Pressurizer Level Signal (LT-1110X) Tap 1-RC-105

Systems affected are PPCS, PLCS, and SBCS.

Evaluation of Pressure Signal and Level Signal Failing Low Due to Instrument Tap Damage on Plant Response:

If malfunction causes a low pressure and level signal to be transmitted, the pressurizer heaters would turn on and the pressurizer sprays would decrease flow. The PLCS would decrease letdown and increase charging. Due to the increase in charging and pressurizer heating the reactor may trip on high pressurizer pressure. The operator has safety grade instrumentation and alarm of high pressurizer level from which to evaluate event progress. Manual control of charging, atmospheric dump valves and auxiliary sprays, without the use of PLCS, PPCS, and SBCS will bring the plant to a stable condition. The excess charging event in Subsection 15.5.3.2 bounds this scenario as it requires earlier operator action.

Evaluation of Pressure Signal and Level Signal Failing High Due to Instrument Tap Damage on Plant Response:

If malfunction caused a high pressure and level signal to be transmitted, the pressurizer heaters would de-energize, the sprays would increase flow. The RRS would adjust rods in response to the high pressure signal thereby decreasing reactor power. The SBCS would receive a lower T_{avg} input due to the decrease in reactor power and not open the TBVs. The PLCS would increase letdown and decrease charging. A low pressurizer pressure situation would occur leading to a possible reactor trip and SIAS on low pressure or a new steady state at lower power and

pressure. The operator has safety grade instrumentations from which to evaluate event progress. Isolation of letdown on SIAS or by the operator and manual control of charging with pressurizer spray isolation will bring the plant to a stable condition without using the PLCS, PPCS, and SBCS.

The reactor trip on low pressure would prevent any fuel from experiencing a DNBR less than 1.19 (CE-1 CHF correlation) and there is no over-pressurization. Since there is no fuel failure or release of primary fluid to the atmosphere, the opening of a letdown relief valve outside containment (Subsection 15.6.3.1) clearly bounds the radiological consequences.

Evaluation of Pressure Signal Failing High and Level Signal Failing Low Due to Instrument-Tap Damage on Plant Response:

The plant response is similar for the PPCS, RRS, and SBCS as discussed above for the pressure signal failing high. The PLCS, however would increase charging and decrease letdown. The increase in charging and pressurizer spray flow with no pressurizer heaters may lead to a low pressure condition or a steadily increasing pressurizer level. The operator has safety grade instrumentation from which to evaluate event progress. Manual control of charging and turning off pressurizer sprays will bring the plant to a stable condition. The conclusions stated for the Pressure Signal and Level Signal Failing High apply to the scenario.

Evaluation of Pressure Signal Failing Low and Level Signal Failing High Due to Instrument Tap Damage on Plant Response:

As discussed in the evaluation for both signals failing low the PPCS and SBCS response is similar. The PLCS, however would increase letdown and decrease charging. The operator can manually control charging to increase pressurizer level and isolate letdown flow. The plant can be brought to a stable condition through operator action and manual control of the PPCS, PLCS, and SBCS.

For this scenario the reactor would trip on low pressure and prevent any fuel pins from experiencing a DNBR less than 1.19. Since there is no fuel failure or release of primary fluid to the atmosphere for this event, the opening of a letdown relief valve outside containment in Subsection 15.6.3.1 bounds this scenario.

<u>Pressurizer Pressure Signal (PT-1100Y) and Pressurizer Level Signal (LT-1110Y Tap 1-RC-130)</u>

The systems affected and the evaluation of plant response are the same as those described above for pressurizer pressure signal (PT-1100X) and pressurizer level signal (LT-1110X).

<u>Steam Generator Level Signals (LT-9005 and LT-9012) Tap 1-1"-MSL-106</u>

System affected is the FWRS.

Evaluation of Level Signals Failing Due to Instrument Tap Damage on Plant Response:

Wide range steam generator level will indicate a low level condition on one steam generator. The operator will still have safety grade steam generator level indications to rely on (one safety channel of the four safety channels will also be lost for that steam generator). Additionally, on the same steam generator the narrow range instrumentation and control of the feedwater bypass valve sends a signal to open the valve and actuates a low level alarm in the control room. However, since a turbine trip signal is not present, it will not open the valve. For conservatism it is assumed to open increasing flow to the steam generator. The intact portion of the FWRS on that steam generator will see the increased level and close the regulating valve enough to maintain level. Should this regulating valve control work improperly, a high steam generator level will cause closure of the feedwater regulating valves and turbine trip. The operator can use the auxiliary feedwater system to maintain adequate inventory in the affected steam generator and may choose to manually trip the plant based on safety grade instrumentation readings conflicting with process instrumentation and control actions. The scenario is bounded by the Increased Feedwater Flow event in Subsection 15.1.2.1 which assumed the maximum feedwater flow due to a failure in the FWRS.

Evaluation of Level Signals Failing High Due to Instrumentation Tap Damage on Plant Response:

Wide range steam generator level will indicate a high level condition on one steam generator. The operator will still have safety grade steam generator level indications to rely on (one safety channel of the four safety channels will also be lost for that steam generator). The control and instrumentation for the bypass valve will see the high level signal and actuate a high level alarm in the control room.

The operator based on safety grade instrumentation will see normal level because the FWRS valves are not acting improperly. However, due to erronous level signals he may take manual control of the FWRS and eventually trip the reactor using auxiliary feedwater to control steam generator inventory.

Evaluation of One Level Signal Failing High and One Level Signal Failing Low Due to Instrument Tap Damage on Plant Response:

Wide range steam generator level indication does not control a system and the operator will compare it to safety-related instrumentation to ascertain the true reading. Failure of the instrumentation and control of the feedwater bypass valve is discussed previously.

<u>Steam Generator Level Signals (LT-9006 and LT-9022) Tap 1-1" MSI-114</u>

The systems affected and evaluation of plant response are the same as for steam generator level signals LT-9005 and LT-9012 for instrument tap 1-1" MSI-106.

Condenser Storage Tank Level Signals (LT-12-11A and LT-12-11B)

The other control channel transmitters sharing a common tap not identified in the table are the Condensate Storage Tank level transmitter LT-12-11A and 11B. Individual root valves and excess flow check valves are added to ensure that instrument line rupture in one channel does not affect the other channel. The only failure affecting both channels is the break of the tap. For diversity, two safety-related level switches provide low level alarms on the safety annunciators. Since the function of LT-12-11A and 11B is only indication and alarm and since alarm backup is provided a tap failure would not cause system actions required to be analyzed by Chapter 15 of the FSAR.

15.0.2.6.3 Question No. 420.14 (7.2)

The Reactor Protection System (RPS) includes two trip inputs (turbine trip and loss of component cooling water trip) which are classified as not being required for reactor protection. It is the staff's position (BTP ICSB 26) that all reactor trip inputs to the RPS are required to meet the design requirements of IEEE 279 without exception. This includes the entire trip function from the sensor to the final actuated devices.

FSAR Chapter 15 shows that the accident analysis takes credit for reactor trip on turbine trip. FSAR Subsection 7.2.2.2.11 states that the turbine trip is taken from non-Class IE hydraulic oil pressure switches. The use of non-Class IE switches is not acceptable. Also, it is not clear that the component cooling water trip meets the requirements of IEEE-279.

Therefore, provide a description of these and other such RPS inputs with respect to their conformance to BTP ICSB 26. This design description should be supported with electrical schematics, logic diagrams, piping and instrument drawings, test procedures and technical specifications.

Response

The Chapter 15 accident analysis does not take credit for reactor trip on turbine trip to mitigate the results of any event. This is so stated in note 7 to Table 15.0-7. The sequence of events analyses presented in Chapter 15 recognize that such a trip exists and may occur. For the Increased Feedwater Flow (with failure to achieve a fast transfer at a 4.16 kV bus) event presented in Subsection 15.1.2.1, the reactor trip is assumed to occur on low electrohydraulic pressure following turbine trip. If the reactor trip does not occur on turbine trip the consequences of this event will be similar to but less severe than the loss of condenser vacuum, which is described in Subsection 15.2.2. Tripping the reactor on turbine trip, for this event, maximizes the reactor coolant system cooldown as shown in Figures 15.1.2.1-5,-6 and -7.

a. Loss of CCW Trip

A reactor trip following a loss of CCW to the reactor coolant pumps is provided as an equipment protective feature, but is not required for reactor protection. See FSAR Subsection 7.2.2.5.5.

Four flow transmitters FT-14-15A,B,C & D are located on the CCW common return header to monitor CCW flow from the RCP's. These four transmitters are

powered from redundant Class IE power supplies (MA, MB, MC and MD) and are physically and electrically separated in accordance with the Reg. Guide 1.75.

CCW flow out of the RCP's are continuously monitored and displayed on RTG Board 206 in the control room. Upon detection of loss of CCW from the RCP's an alarm in the control room will alert the operator about the low flow condition so that a proper corrective action can be taken immediately. If flow is not re-established in 10 minutes the RPS is actuated to trip the reactor. The test switches are also provided on the RTG Board 206 to enable testing the indicator-bistable.

The component cooling water trip meets the requirements of IEEE-279-1971 as described in the FSAR Subsection 7.2.2.3.2.

The CCW trip circuit testing is in accordance with the FSAR Subsection 7.2.1.1.9 and plant technical specification.

b. Reactor Trip on Turbine Trip

A reactor trip initiation following a turbine trip is provided as an equipment protective feature, and is not required for reactor protection. See FSAR Subsection 7.2.2.5.4.

The turbine trip circuit for the reactor trip up to the isolation device is classified as non- safety. After the isolation device the circuit (including the isolation device) meets all IEEE 279-1971 requirements as described in FSAR Subsection 7.2.2.3.2. The circuit testing is in accordance with the FSAR Subsection 7.2.1.1.9 and plant technical specification.

General

The turbine trip input cables are terminated at TB 'A' located at the north end of the Turbine Generator Building pedestal and are routed to El 43.00 of the Reactor Auxiliary Building (directly under the Reactor Protection System Cabinet).

Each of the four cables is routed in its own dedicated conduit the entire length and is uniquely identified NMA, NMB, NMC, NMD. No other cable is permitted to be routed with these cables.

The cables concerned are identified as follows:

- Channel NMA 20710 U (NMA)
- Channel NMB 20710 V (NMB)
- Channel NMC 20710 W (NMC)
- Channel NMD 20710 X (NMD)

Specific Cable Routing

TB 'A' is located at the north end of the Turbine pedestal at El 62.00. Each cable is routed in its own embedded conduit in the pedestal and down the pedestal leg. The conduits exit the pedestal leg and run embedded to electrical manholes as follows:

- MH 256 - For Cables 20710 U (NMA) and 20710 W (NMC)
- MH 257 - For Cables 20710 V (NMB) and 20710 X (NMD)

Inside manhole 256, cables 20710 U and 20710 W are routed in their own flexible conduit on opposite sides of the manhole from the west to the east walls. High voltage cables, 6.9 kV and 4.16 kV are routed in this manhole, however the flexible conduits are routed in such a manner so as to maintain a minimum separation of 18 inches from all high voltage cables. This separation is reduced to 12 inches at the west face for a distance of 6 inches, as the flexible conduit converts to an embedded conduit.

Inside manhole 257, cables 20710 V and 20710 X are routed in their own flexible conduit on opposite sides of the manhole from the west to the north walls. Again as was the case from manhole 256, high voltage cables of the 4.16 kV and 6.9 kV class are routed within the manhole. However, the flexible conduits are routed in such a manner so as to maintain a minimum separation of 24 inches from all high voltage cables.

Each manhole although non safety-related and therefore categorized as non-seismic Category 1, is designed similar to, i.e., rebar etc. a seismic manhole such that during a seismic event, MH256 or MH257 will behave similar to a seismically designed manhole and will not fail.

It must be noted that the 4.16 kV and 6.9 kV cables are designed with metallic lead sheaths and all cable is Class IE qualified, meeting the requirements of IEEE-383.

The cables exit the manholes in their own embedded conduits and are routed into the Reactor Auxiliary Building basement where they enter pull boxes. From each pull box, the cables are routed in their own separate and independent conduits up the west Reactor Auxiliary Building wall to the isolation boxes mounted under El 62.00 just below the RPS cabinet. From the isolation boxes, the Class IE cables 20710H-(MA) 20710J-(MB) 20710K-(MC) and 20710C-(MD) are routed in their own conduits and enter their respective sections of the RPS Cabinet.

On the basis of the special treatment of these cables, beyond the requirements of Reg. Guide 1.75, as described above, we can see no credible event where cables of high voltage (6.9 kV and 4.16 kV) can come in contact with the turbine trip cables to the RPS.

Turbine trip inputs to the RPS are properly isolated through separate-mounted isolation relay box. The relay box is a NEMA 4 type construction, with adequate mounting and physical separation design that meet IEEE-344-1975 and Reg. Guide 1.75 requirements.

The isolation relay is Agastat EGP type which has been qualified to IEEE-323-1974. As described in the attached system control report, the EGP type relay provides at least 2000 volt RMS isolation from the coil side to the contact side.

Testing of Agastat EGP Relays

On October 30, 1980, Systems Control conducted tests on two Agastat EGP relays which are IEEE-323 prequalified type relays. The first relay, Table 15.0-23, was a type EPG1001, serial number 80411508, and with a 120V ac, 60 Hz coil. The second relay Table 15.0-24 was a type EPGD001, serial number 80411510, and with a 125V dc coil. The test was divided into two parts. In part one, both relays were subjected to upwards of 5,000V dc and the leakage current measured. A Hipotronics series 300 Hipot and Megohmeter, last calibrated on March 18, 1980, was used to supply the voltage and measure the leakage current.

Each test vehicle was attached to a type CR0095 socket and properly seated in place with type CR0155 locking straps. (See the attached data sheet on Agastat sockets and straps.) The relays and sockets were then mounted on a 2 x 6 wood board.

The test was effected by attaching the hot lead from the Hipot and Megohmeter to one side of the relay coil while the ground lead was connected to one of the contact connections. The voltage was then increased from zero to either 5,000 volts or until the Hipot and Megohmeter automatically shut itself down when the leakage current exceeded 5.5 milliamperes. The voltage was then reduced to zero and the ground lead attached to another contact connection and the test repeated. When all the contact connections had thusly been tested, the Hipot and Megohmeter hot lead was connected to the other side of the coil and the whole series of tests repeated. During automatic shutdown, the highest attainable voltage was recorded.

In view of the above, we must conclude the Agastat EGP type relay will qualify to the specified 2,000 volts RMS isolation. In addition, the manufacturer guarantees a 2,000 volt RMS isolation for the Agastat relay.

15.0.2.6.4 Question No. 420.45 (7.7)

The last statement in Subsection 7.7.2 states that the safety analyses of Chapter 15 do not require the systems discussed in Section 7.7 to remain functional. However, the first paragraph of Subsection 15.0.2.3 states that several normally operating control systems (including some discussed in Section 7.7) are assumed to function during certain accidents. Resolve this inconsistency.

Response

Except as discussed below, operation of the control systems described in Section 7.7 is not required in order to mitigate the consequences of the transients analyzed in Chapter 15. The analyses in Chapter 15 include the assumption that these control systems respond normally to each transient, but that their operational mode is that which would be most adverse for the transient under consideration. The consequences produced by a malfunction of these control systems would be less severe than the additional failures considered in the transients analyzed in Chapter 15. The sequence of events diagrams accompanying the Chapter 15 analyses clearly demonstrate that there is a safety grade backup for control system actions, or that the control system actions is not required.

Specific control system failures are evaluated as low-probability independent occurrences (i.e. single failures) and are listed in Table 15.0-3. The treatment of these low-probability independent occurrences is discussed in Subsections 15.0.1.5.2 and 15.0.2.3.

Two low-probability event scenarios merit additional clarification. These scenarios postulate operation of systems which are of high reliability, although control grade, to terminate an initiating event with a single failure.

1. With the failure of a main steam isolation valve (MSIV) to close following a steam line break event, control systems are assumed to operate normally as discussed above. For this event, the turbine trip will terminate steam flow. The turbine trip is actuated by diverse and redundant means from those actuating the MSIS. As a single failure of a protective system is already assumed, it is considered inappropriate to consider an additional failure in this analysis.

2. The excess feedwater event is terminated due to the actuation of control grade equipment by appropriately isolated safety grade signals, assuming no credit for prior operator action is taken. These signals are actuated by two-out-of-four logic from the safety grade protective channels of the RPS steam generator level transmitters. The signals are isolated from the non-class IE equipment they actuate as described in Subsection 7.2.2.3.2 (4.7.1) of the FSAR. Diverse and redundant equipment is actuated by these signals. First, after the initiating event, high level protection closes the feedwater control valve(s), as shown on Figure 7.7-5. Second, if the high level protection should fail, the high-high level protection will trip the turbine, stop the main feedwater pumps and close the main feedwater pump discharge valves.

15.0.2.6.5 Question No. 440.10

Confirm that during the preoperational or start-up test phase you intend to verify the response times (such as opening and closing times for main feedwater, auxiliary feedwater, turbine and main steam isolation valves), to show that they have been conservatively modeled in the Chapter 15.0 analyses.

Response

The Preoperational Test Program discussed in Chapter 14 includes tests which are performed to verify the above information which is input to the Chapter 15.0 analyses. Section 14.2 describes the individual tests that were performed.

Feedback from these tests to the safety analysis is accomplished by three principal means: review of test results to confirm analysis assumptions (e.g., valve operating times) and Field Action Requests (FARs), which are reports of any tests which do not meet the specified requirements and; personal observation of some critical tests (e.g., four RCP loss of flow).

15.0.2.6.6 Question No. 440.13 (15.0)

For each accident, discuss non-safety grade equipment which was assumed to operate and could result in the transient becoming more severe or verify that no non-safety grade equipment operating would produce a more severe transient. For example, the pressurizer heaters being energized for a transient resulting in high RCS pressures could tend to worsen the effects of the transient. Likewise, pressurizer spray could be detrimental for a transient resulting in low RCS pressure.

Response

Normally operating, non-safety control systems are assumed to function during the course of the events described in Chapter 15 of the FSAR. In general, automatic operation of these control systems is assumed unless operation in the manual mode would make the approach to acceptance guidelines more limiting. In the manual mode, the control system is assumed to continue to function as it was prior to the event until an appropriate time has elapsed for operator actions. Events with a loss of offsite power do not consider the response of many control systems since they are inoperable during loss of power.

A control system may have a pre-existing failure which could cause it to function abnormally when in the automatic mode. Such a Low or High Probability Independent Occurrence may be included in the definition of some events and the result of this additional failure is considered during the safety evaluation. Backup systems, which will operate if control systems malfunction, are shown on the sequence of events diagrams (SEDs) as alternative paths. The SEDs also show the mode of operation of the control systems and plant safety systems that respond to the transients.

The following are examples of how the control systems were assumed to operate to make the results in the accident analyses more severe:

1. The Loss of Main Steam with a failure to achieve fast transfer of a 6.9KV bus (Subsection 15.1.4.3.) considered the pressurizer pressure and level control systems to be in the manual mode of operation (Table 15.1.4.3-2) so they did not function to mitigate depressurization of the RCS. This resulted in a lower RCS pressure which in turn minimized DNBR.

2. The Isolation of Turbine (Subsection 15.2.1.2) considered the pressurizer pressure and level control systems and steam bypass control system to be in the manual mode of operation (Table 15.2.1.2-2). Without the opening of the steam bypass control valves, secondary pressure and temperature rise, affecting primary to secondary heat transfer. This causes a heat-up in the RCS with a maximum pressure increase since the pressure and level control systems do not function to mitigate the pressurization.

3. The Loss of Offsite Power (Subsection 15.3.2) does not take credit for any control systems (Table 15.3.2.2-2) since they are inoperative on loss of offsite power. With the steam bypass control system unavailable there is a rapid buildup in secondary pressure and temperature. This reduces primary to secondary heat transfer and a further decrease in heat transfer is experienced as the reactor coolant pumps coast down. Core coolant temperature increases leading to an RCS pressure increase which is not mitigated because the pressurizer pressure and level control systems are inoperable.

4. The CEA Ejection with a failure to achieve fast transfer of a 4.16KV bus and a high steam generator tube leakage rate (Subsection 15.4.5.1) considered the steam bypass control system to be in manual mode and the reactor coolant pumps to be operational (Table 15.4.5.1-2) (RCPs would not be operable if a loss of offsite power was chosen). The offsite dose is maximized because the steam generators relieve steam to the atmosphere and the reactor coolant pumps provide for greater primary

to secondary heat transfer, and hence greater steam release while the high steam generator tube leakage rate maximizes the activity.

5. The Primary Mass Addition (Subsection 15.5.3.2) assumes the pressurizer level signal failing low with the pressurizer level and pressure control systems to be in the automatic mode to maximize the pressurizer level and pressure increase. However, even with the control systems in their most adverse mode, the resulting pressure is not limiting in its approach to the acceptance guidelines.

6. The Loss of Primary Fluid to Secondary System (i.e., Steam Generator Tube Rupture; Subsection 15.6.2.1) considered the pressurizer level and pressure control systems to be in automatic and the steam bypass to be in manual (Table 15.6.2.1-2). The pressurizer level and pressure control systems, in automatic, maintain a higher RCS pressure longer delaying reactor trip, and increase the integrated reactor coolant leakage to the faulted steam generator. The steam bypass control system being in manual mode (valves closed) causes steam to be diverted to the atmosphere through the main steam safety valves, maximizing offsite dose.

15.0.2.6.7 Question No. 440.18 (15.2.2.1)

Discuss the system used to provide pressurizer heater cutoff on low level. Is there any single failure that could result in the heaters remaining energized when they have lost submergence. If so, discuss the consequences of this occurrence. In your answer, you may wish to consider the event which occurred at the Spert III facility in Idaho where a pressurizer was heated to a point where it lost integrity.

Response

Redundant Class 1E low pressurizer level cutoff signals are provided to the pressurizer heaters. These signals will de-energize the heaters prior to the water level dropping below their tops so that no single failure in the protection system causes them to be energized while uncovered.

15.0.2.6.8 Question No. 440.82

All Chapter 15 analyses assumed operator action for auxiliary feedwater initiation. In light of NUREG 0737 requirements to incorporate automatic initiation of the auxiliary feedwater system, we require that the applicant reanalyze the depressurization transients accounting for auxiliary feedwater as it would be initiated without operator intervention. A detailed description of the auxiliary feedwater system, as modified for automatic initiation, should also be provided.

Response

In Chapter 15, manual actuation of AFW was usually assumed at thirty minutes following the initiating event. A few accidents required earlier AFW actuation, the most limiting being the large feedwater line break with a loss of offsite power event presented in Subsection 15.2.5.2. For this event AFW actuation was required at 225 seconds. Automatic actuation is designed to supply AFW to the intact steam generator(s) within 120 seconds. This earlier actuation produces less adverse consequences for all events, except possibly increased RCS heat removal events. For increased RCS heat removal events, there is no impact of automatic AFW initiation prior to reactor trip, since the system would not actuate prior to this time. Following trip, depending on how the actuation logic would feed the steam generators, automatic AFW initiation could

incrementally increase the cooldown of these events. However, none of the conclusions of the analyses would be changed.

Table 15.0-25 compares the maximum post-trip core average powers, maximum post-trip reactivities, and minimum post-trip DNBRs for the increased heat removal case with the most adverse post-trip DNBR with and without automatic initiation of auxiliary feedwater. (This case is the 6.36 ft^2 main steam line break initiated at full power inside containment, with a loss of offsite power, a HPSI pump failure, and a stuck CEA, which is presented in Subsection 15.1.6. Although the minimum DNBR is incrementally lower for the case with automatic auxiliary feedwater, the value is still well above any fuel failure threshold. The minimum post-trip DNBR for all other cases is at least a factor of two greater than for this case (see Subsection 15.0.4.4.4).

A description of the auxiliary feedwater system, as modified for automatic initiation, is provided in Section 7.3 and Subsection 10.4.9 of the FSAR.

15.0.3 PLANT CHARACTERISTICS CONSIDERED IN SAFETY EVALUATION

15.0.3.1 Initial Conditions

The events discussed in this chapter have been analyzed over a range of values for the principal process variables that affect offsite doses, Reactor Coolant System pressure, and margin to fuel thermal design limits. These variables include the core power level, the core power distribution, the core coolant inlet temperature, the primary system pressure, the pressurizer level, the steam generator level, the secondary system pressure, and the feedwater temperature.

The range of initial conditions used for analysis is compatible with the Technical Specification on the various process variables. These ranges bound the space for which the Chapter 15 analysis is valid. The range of values for each of the principal process variables that was considered in the Chapter 15 analyses is listed in Table 15.0-9.

15.0.3.2 Input Parameters

The parameters used in the analyses of Chapter 15 are consistent with those listed in Section 4.3.

15.0.3.2.1 Doppler Coefficient

The effective fuel temperature coefficient of reactivity (Doppler coefficient) is shown on Figure 4.3-34 for beginning of cycle (BOC) and end of cycle (EOC) conditions. These curves were adjusted up and down by 15 percent to conservatively account for uncertainties in determining the actual fuel temperature reactivity effects. A Doppler weighting factor is specified for each analysis. For transients where less Doppler feedback produces more adverse results, a value of 0.85 is used. For transients where more Doppler feedback produces more adverse results, a value of 1.15 is used.

The effective fuel temperature correlation is discussed in Section 4.3. This correlation relates the effective fuel temperature, which is used to correlate Doppler reactivity, to exposure and the local core power. These temperatures are adjusted and used in the CESEC II and CESEC SLB computer codes to evaluate Doppler reactivity. For the CEA ejection analysis, a polynomial

correlation is used in the STRIKIN computer code to evaluate Doppler reactivity because of the rapid variations in fuel temperature which occur during this transient.

15.0.3.2.2 Moderator Temperature Coefficient

For all event analyses except the steam line break and feedwater pipe break event analyses, the range of moderator temperature coefficients of reactivity considered for hot full power conditions (T_{avg} = 573 F) is 0.00 Δρ/F to -2.88 x 10^{-4}Δρ/F. For hot zero power conditions T_{avg}= 532 F), the range is 0.1 x 10^{-4} Δρ/F to -2.10 X 10^{-4} Δρ/F. Some analyses may use more conservative values. These values include all uncertainties, and bound the expected moderator temperature coefficients for all cycle one exposures, power levels, CEA configurations, and boron concentrations.

The most conservative, allowable value for the moderator temperature coefficient is assumed for each individual analysis. Table 4.3-3 provides values for the moderator temperature coefficient for various event analyses.

The steam line break and feedwater pipe break analyses use reactivity as a function of moderator temperature instead of a moderator temperature coefficient to model moderator feedbacks. This is because of the large moderator temperature variations which occur during these events.

15.0.3.2.3 Shutdown CEA Reactivity

The shutdown reactivity is dependent on the CEA worth available on reactor trip, the axial power distribution, the position of the regulating CEAS, and the time in core life. For transient analyses other than CEA ejection and steam line break (SLB), conservative values of the negative reactivity worth of the CEAs available for a reactor trip of 5.50 percent and 2.50 percent were used for hot full power (HFP) and hot zero power (HZP), respectively. For CEA ejection events, conservative values of 5.05 and 1.53 percent were used for HFP and HZP, respectively. The foregoing values include uncertainties, the most reactive CEA stuck in the fully withdrawn position, and the effect of cooldown to HZP temperature conditions (Subsection 4.3.2.4.3).

For SLB analyses the CEA worths used depended upon whether or not the particular analysis assumes that the most reactive CEA is stuck in the fully withdrawn position. For SLB events at full power, conservative CEA worths of 6.68 and 7.78 percent were used for cases with and without a stuck CEA, respectively. These values include uncertainties and the penalties appropriate to HFP as indicated in Table 4.3-7. An additional 0.96 percent was subtracted from the full power CEA worth for those SLB analyses done to maximize the potential for post-trip return-to-power. This 0.96 percent corresponds to the sum of the thermal hydraulic effect and loss of CEA worth which are associated with reduction from HFP to HZP (Table 4.3-6). These two effects are included in the moderator cooldown reactivity function for other analyses. Inclusion of these effects as a loss in CEA worth, rather than as an increase in moderator cooldown reactivity, reduces pre-trip power increases and therefore increases total cooldown and the consequent potential for post-trip return-to-power. For SLB events initiated from HZP, a conservative CEA worth of 5.00 percent was sufficient to ensure insignificant post-trip return-to-power. This value covers uncertainties, the most reactive CEA stuck in the fully withdrawn position, and the penalties appropriate to HZP as indicated in Table 4.3-7.

Table 15.0-9a summarizes the above CEA worths. The power dependent insertion limit (PDIL) which will be included in the Technical Specifications assures that these worths are available upon reactor trip.

The shutdown reactivity worth vs. position curve which was employed in the Chapter 15 analyses is shown on Figure 15.0-1. This shutdown worth vs. position curve predicts a lower rate of reactivity insertion than is expected under any allowed initial condition. Accordingly, it is a conservative representation of shutdown reactivity insertion rates for reactor trips which occur as a result of an event.

15.0.3.2.4 Effective Delayed Neutron Fraction

The effective neutron lifetime and delayed neutron fraction are functions of fuel burnup. For each individual analysis, one of the following values of the neutron lifetime and the delayed neutron fraction is selected, depending upon time in life analyzed.

	Neutron Lifetime (10-6 sec)	Delayed Neutron Fraction
BOL	29.0	0.007321
EOC	30.8	0.005365

15.0.3.2.5 Decay Heat Generation Rate

Analyses based on full power initial conditions conservatively assume a decay heat generation rate based an the 1971 Proposed ANS Decay Heat Standard including contributions from heavy element decay and is based on an infinite reactor operation period at full power,

15.0.3.2.6 CEA Clarification NRC Questions (Cycle 1)

15.0.3.2.6.1 Question No. 440.78

Verify our understanding that the majority of the Section 15 transients were evaluated without the assumption of a stuck CEA in the fully withdrawn position. If this is the case, then we require all analyses to be re-evaluated with a limiting CEA withdrawn. As it stands, the analyses are not in compliance with the General Design Criteria (i.e., GDC-26) nor with the appropriate Standard Review Plans.

Response

All Chapter 15 events were evaluated with the assumption that the highest worth CEA was stuck in the fully withdrawn position following reactor trip. (See Subsection 15.0.3.2.3. For all events, except steam line break (SLB), credit was not taken for the shift in estimated occurrence frequency associated with a stuck CEA. That is, all events, other than SLB, were conservatively placed in the frequency group appropriate to the assumption of no stuck CEA, even though the CEA worth available for reactor trip which was used for the analyses included the assumption of a stuck CEA.

SLB in combination with a stuck CEA and failure fast transfer is found in the limiting Fault-3 frequency category of Section 15.1. (See Table 15.1.5-1.) This combination results in a significant degradation of fuel performance, mainly due to failure to fast transfer, but is less

limiting than SLB in combination with loss of offsite power. Consequently, SLB in combination with loss of offsite power is presented in the Limiting Fault-3 frequency category of Section 15.1. SLB, in combination with a stuck CEA plus single failure and loss of offsite power, as identified in the Standard Review Plan, has been evaluated with respect to fuel performance. See Subsection 15.1.6.

15.0.3.3 Part Length Control Rods

The original design of St Lucie Unit 2 included part length control rods and this design was reflected in the original FSAR. Subsequently, FP&L has removed the part length control rods from the St Lucie Unit 2 design with the concurrence of Combustion Engineering.

The analyses presented in Chapter 15 do not credit the shutdown worth of the part length control rods (PLRs) and will not be affected whether or not PLRs are used. Several of the events presented in Section 15.4 assume PLR insertion as an initial condition. These events were found to be the limiting reactivity events in their frequency category. Thus, the results of these analyses bound the results which would be obtained for analyses performed on a core that precludes PLR insertion. In conclusion, the results of the Chapter 15 analyses bound the results which would be obtained whether or not PLRs are used.

15.0.4 EVALUATION MODELS

15.0.4.1 Mathematical Models

15.0.4.1.1 CESEC

Described in Section 15.0.14.4

15.0.4.1.2 STRIKIN-II

The STRIKIN-II computer program is used to simulate the heat conduction within a reactor fuel rod and its associated surface heat transfer. The STRIKIN-II program is described in CENPD-135-P[6]

The STRIKIN-II computer program provides a single, or dual, closed channel model of a core flow channel to calculate the clad and fuel temperatures for an average or hot fuel rod, and the extent of the zirconium water reaction, for a cylindrical geometry fuel rod. STRIKIN-II includes:

a. A point kinetics reactor model incorporating all major reactivity feedback mechanisms (refer to CENPD-190-A[7] for a description of all input utilized in the point kinetics model).

b. A maximum of six delayed neutron groups.

c. Both axial (maximum of 20) and radial (maximum of 20) segmentation of the fuel element.

d. Control rod scram initiation on high neutron power.

15.0.4.1.3 TORC

The TORC computer program is used to simulate the fluid conditions within the reactor core and to predict the existence of departure from nucleate boiling (DNB) on the fuel rods. The TORC program is described in References 8 and 9.

15.0.4.1.4 COAST

The COAST computer program is used to calculate the reactor coolant flow coastdown transient for any combination of active and inactive pumps and forward or reverse flow in hot or cold legs. The program is described in Reference 10.

The equations of conservation of momentum are written for each of the flow paths of the COAST model assuming unsteady one-dimensional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal points. Pressure losses due to friction and geometric losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

15.0.4.1.5 Reactor Physics Computer Programs

Numerous computer programs are used to produce the input reactor physics parameters required by the NSSS simulation and reactor core programs previously described. These reactor physics computer programs are described in Chapter 4.

15.0.4.2 Operator Action Model

Operator actions assumed to mitigate the consequences of the events are delineated on the sequence of events diagram which accompanies each writeup (by an "M" in the action box, see Subsection 15.0.2.1). The operator is alerted to the need for action by an unambiguous alarm or sampling, an unambiguous alarm is one, which within the time period allowed for diagnosis, would make the operator aware of the need to take the action assumed. There may or may not be redundant or diverse plant alarms for a particular action; however, there are always continuously operating, visual indications in the control room of relevant plant process para-meters, other than those that result in alarms, that serve as back-ups.

A time delay is assumed between the unambiguous alarm and the accomplishment of any manually initiated action. This delay conservatively accounts for the time required by the operator to diagnose the event, decide what action to perform, and execute this action. At no time, during the events considered in the evaluation, is the operator assumed to perform an action outside the control room in less than 30 minutes following an unambiguous alarm. For those actions performed within the control room, the minimum delay time assumed depends on the event frequency (to account for expected operator experience) and relative complexity of action.

In general, unless otherwise noted, minimum delay times assumed are 10 minutes for Moderate Frequency events, 20 minutes for Infrequent events, and 30 minutes for Limiting Faults. However, for relatively simple actions performed frequently, such as auxiliary feedwater initiation, shorter operator action times are assumed.

The analysis considers operator errors of commission and omission. Errors of commission are bounded by the coincident occurrences discussed in Subsection 15.0.1.5. Errors of omission will either leave the plant in a safe state, will actuate an alarm to alert the operator, or are protected against by a backup safety system. It is assumed that the plant is operated in accordance with the appropriate operating and emergency procedures.

15.0.4.3 Activity Release Methodology

A conservative method of calculating isotopic activity releases produced by the initiating events was utilized to select the most limiting event combination in each matrix element and to compare events to the offsite doses acceptance guidelines given in Table 15.0-4.

15.0.4.3.A Question 440.12 - Operator Action NRC Question (Cycle 1)

Verify that for each transient analyzed in Chapter 15, if operator action is not discussed then no operator action is required. In particular, consider events in which the ECCS is actuated or RCP trip would be required based on present procedures.

If operator action is anticipated regardless of whether or not it is required, discuss this action and its impact on the consequences. Include a discussion of the potential for operator error.

Response

Operator actions are discussed for each event for which a major write-up is presented in Chapter 15. These actions are discussed in the following parts of the write-up:

1. Section 15.X.Y.Z.2: Sequence of Events and System Operation;

2. Table 15.X.Y.Z-1: Sequence of Events, Corresponding Times and Summary of Results;

3. Figure 15.X.Y.Z-1: the Sequence of Events Diagram (SED).

If operator action is not discussed, no manual action is required to mitigate the consequences of the event.

In order to mitigate consequences of the small break loss of coolant accident (LOCA) the NRC has required (via I&E Bulletin 79-06C) operator action to trip all reactor coolant pumps (RCPs) following a safety injection actuation signal (SIAS) on low pressurizer pressure. The small break LOCA analysis is not presented in Chapter 15 of the FSAR. Therefore, in addition, none of the events presented in Chapter 15 require RCP trip following SIAS on low pressurizer pressure in order to mitigate consequences.

If RCP trip is also required for the St. Lucie Unit 2 plant in order to mitigate consequences of small break LOCA, events other than LOCA which result in SIAS on low pressurizer pressure will be affected. RCP trip following SIAS is not expected to leave a significant impact on offsite dose since it will not affect the integrity of barriers to fission product release.

RCP trip following SIAS can impact reactor coolant system pressures due to the loss of the normal method of pressurizer spray operation which derives its flow from the pressure head

supplied by the RCPs. However, the operator can use the auxiliary spray, which derives its flow from the charging pumps, to control pressurizer pressure.

The pressurizer pressure setpoint for SIAS is lower than the setpoint for reactor trip; therefore, SIAS follows reactor trip. Consequently, RCP trip following SIAS will not affect pre-trip or short term post- trip fuel performance. In the case of the steam line break event, RCP trip following SIAS does adversely affect long term post-trip reactivity and DNBR. As is discussed in Subsection 15.1.5.3.5, for the steam line break event RCP trip following SIAS causes an increase in post-trip reactivity and a decrease in post-trip DNBR; however, consequences are not as adverse as for the steam line break with concurrent loss of offsite power presented in Subsection 15.1.6.

The Chapter 15 analysis considers operator errors of commission and omission. Errors of commission are bounded by the coincident occurrences discussed in Subsection 15.0.1.5. Errors of omission will either leave the plant in a safe state, will actuate an alarm to alert the operator, or are protected against by a backup safety system. It is assumed that the plant is operated in accordance with the appropriate operating and emergency procedures. To assure that this is so, Combustion Engineering prepares procedure guidelines to assist the utilities in the preparation of these procedures. An example of these is CEN 152, Emergency Procedure Guidelines, prepared for the Combustion Engineering Owners' Group.

Note:

The above discussion is maintained as-is for historical purposes. However, the Emergency Operating Procedures have been revised to allow for two RCP's, 1 in each loop, to remain in operation for a Non-LOCA depressurization event (pressurizer pressure <1300 psia following SIAS and RCS subcooling >20°F). This change was provided by Combustion Engineering Emergency Procedures Guidelines, CEN-152, and analyzed in CEN-268 which was reviewed by the NRC.

15.0.4.3.1 Primary System Initial Activities

Two sets of primary system isotopic specific activities were considered: nominal and high pre-existing iodine concentration (see Subsection 15.0.1.5.3). The nominal pre-existing iodine concentration is based on a conservative evaluation of plant operating history and corresponds to a specific activity of 0.4 μ Ci/gm of I-131 dose equivalent curies (DEC). The high pre-existing iodine concentration is based upon one percent failed fuel cladding and corresponds to an activity of 5.0 μ Ci/gm of I-131 DEC. An event combination which includes an initial condition for specific activity associated with failed fuel cladding is less probable than an identical event combination for which the nominal specific activity is assumed and, thus, may be in a lower frequency category.

15.0.4.3.2 Iodine Spike

For every event, an increase in RCS iodine concentration was assumed (iodine spike). The increase in activities with time is calculated assuming the cleanup systems are inoperable. This assumption results in an iodine specific activity level which increases linearly with time. The nominal rate of increase in RCS iodine concentration which is always included unless otherwise stated, is based upon a conservative evaluation of operating history, is characterized by a spiking factor of 100. A high rate of increase in RCS iodine concentration, based upon maximum observed values, is characterized by a spiking factor of 500[11]. An event resulting in a

spiking factor of 500 is less probable than one resulting in a spiking factor of 100 and, thus, may be in a lower frequency category.

15.0.4.3.3 Fuel Cladding Failures

Releases of gas gap activities from pins calculated to experience cladding failure were considered. For each pin calculated to experience clad failure, a conservative fraction (10 percent) of the total pin activity of iodines and noble gases is assumed to be present in the gas gap[12]. This amount is assumed to be released instantaneously to the reactor coolant. This release increases the primary system specific activities.

15.0.4.3.4 Secondary Activity

A set of secondary side specific activities was used to calculate releases from the steam generators. The DEC I-131 activity corresponding to this set of specific activities is 0.1 μ Ci/gm, as specified in the technical specifications.

15.0.4.3.5 Tube Leakage

All events considered were analyzed assuming some amount of primary-to-secondary tube leakage. A nominal value of leak rate (20 gal/day), based upon a conservative evaluation of operating history, and the maximum value of leak rate allowed by the Technical Specifications (one gal/min) were used. Events assuming a one gal/min leak rate are less probable than identical events assuming the nominal leak rate (see Subsection 15.0.1.5.8) and thus, may be in a less probable event category.

15.0.4.3.6 Decontamination Factors

A conservative set of decontamination factors for iodine releases from the primary and secondary side was used to calculate activity releases to the atmosphere. These values are presented in Table 15.0-10.

15.0.4.4 Fuel Performance Models and Acceptance Guidelines

The acceptability of fuel rod performance is assessed by comparing the predicted thermal and mechanical behavior to appropriate guidelines. Figure 15.0-2 shows the computer codes used in the analyses and the flow of information between codes. The CESEC, TORC, and STRIKIN-II codes are described in Subsection 15.0.4.1. The transient core average power, core average heat flux, and core inlet average coolant conditions from CESEC are input to STRIKIN-II and TORC. STRIKIN-II predicts hot rod fuel and cladding temperatures, the pressure differences across the cladding, and departure from nucleate boiling ratio (DNBR) based on a closed-channel hydraulic model. TORC predicts the DNBR throughout thereactor core based on an open-channel hydraulic model.

The following subsections describe the models and fuel behavior acceptance guidelines for events of moderate frequency, infrequent events, and limiting faults.

15.0.4.4.1 Fuel Performance Models and Acceptance Guidelines for Events of Moderate Frequency

a. Departure from Nucleate Boiling Ratio

The specified acceptable fuel design limit (SAFDL) on DNBR is that the minimum DNBR shall provide at least a 95 percent probability with a 95 percent confidence of not experiencing DNB on the fuel rod with that DNBR (see Section 4.4). A DNBR value of 1.19 using the CE-1 correlation in the TORC code provides at least a 95 percent probability with a 95 percent confidence that the fuel will not experience DNB. Compliance with this limit ensures that there is a low probability of fuel rods being damaged due to cladding overheating.

The core average heat flux, core inlet coolant temperature, core inlet flow, and coolant pressure from CESEC are input to TORC. TORC predicts steady state minimum DNBR values at specified times during the transient.

b. Fuel Temperature

The SAFDL on fuel temperature is that no significant fuel melting occur during the transient. In demonstrating compliance with this guideline, the fuel melting point is assumed to be 5080 F reduced by 58 F for each 10,000 MWd/MTU (see Section 4.4). Compliance with this ensures that the fuel rod is not damaged as a result of material property changes and increases in fuel pellet volume which could accompany fuel melting.

For transients during which an approach to the fuel temperature SAFDL is expected, explicit fuel temperature calculations are performed with the STRIKIN-II code. STRIKIN-II input from CESEC includes core average neutron power, core inlet coolant temperature, core inlet flow, and coolant pressure.

c. Radioactivity Release From Fuel Rods

Radioactivity release from fuel rods during events of moderate frequency is limited to prevent exceeding the acceptance guideline on site boundary dose in Table 15.0-4. Compliance with this guideline is ensured by meeting the DNBR and fuel temperature SAFDLS described in items a and b above, thereby precluding significant cladding damage.

d. Coolable Core Geometry

Fuel geometry is maintained such that continued removal of decay heat is ensured. This guideline is met by meeting the DNBR and fuel temperature SAFDLs prior to cooling the Reactor Coolant System to Mode 4. Thereafter, this guideline is met by preventing the fuel from exceeding the SAFDL on fuel temperature and the SAFDL on DNB. The analysis of all events has been taken to the point of showing decreasing fuel temperature, increasing DNBR and a sufficient coolant inventory to meet the guideline stated herein.

15.0.4.4.2 Fuel Performance Models and Acceptance Guidelines for Infrequent Events

a. Departure from Nucleate Boiling Ratio

The DNBR SAFDL (See Subsection 15.0.4.4.1.a) is also applied to infrequent events.

b. Fuel Temperature

The fuel temperature SAFDL (see Subsection 15.0.4.4.1.b) is also applied to infrequent events.

c. Radioactivity Release From Fuel Rods

Radioactivity release from fuel rods during infrequent events is limited to prevent exceeding the acceptance guideline on site boundary dose in Table 15.0-4. Compliance with this guideline is ensured by meeting the DNBR and fuel temperature SAFDLs described in items a and b above, thereby precluding significant cladding damage.

d. Coolable Core Geometry

Fuel geometry is maintained such that continued removal of decay heat is ensured. This guideline is met by meeting the fuel temperature

SAFDL and limiting the duration of DNB prior to cooling the Reactor Coolant System to Mode 4. Thereafter, the guideline is met by preventing the fuel from exceeding the SAFDL on fuel temperature and the SAFDL on DNB. The analysis of all events has been taken to the point of showing decreasing fuel temperatures, increasing DNBR and a sufficient coolant inventory to meet the guidelines stated herein.

15.0.4.4.3 Fuel Performance Models and Acceptance Guidelines for Limiting Faults

a. Radioactivity Release From Fuel Rods

A small fraction of the fuel rods can be predicted to release radioactive gases for limiting fault events. Even though the occurrence of DNB does not necessarily lead to cladding failure, radioactive gas release from the fuel-cladding gap and fuel rod gas plenum is conservatively assumed to occur when DNB is predicted to occur. The probability of DNB occurring is a function of the DNBR. The total number of rods which are predicted to experience DNB is a summation over the reactor core of the number of rods with a specific DNBR times the probability of DNB at that DNBR. This method is described in Section 5.2 of Reference 13 with the following exceptions:

1) The CE-1 correlation is used instead of the W-3 correlation.

2) Conservative radial power distributions applicable to the St. Lucie Unit 2 core are used.

3) A burnout (DNB) probability function applicable to the CE-1 correlation at 95 percent confidence is used.

4) The TORC code is used to compute coolant conditions and DNBR values.

The core average heat flux, core inlet coolant temperature, core inlet low, and coolant pressure from CESEC are input to TORC. TORC then predicts steady state minimum DNBR values at specific times during the event. TORC is also used to compute the minimum DNBR as a function of radial peak for the conditions prevailing at the time of minimum DNBR.

For the CEA ejection event, radioactive gases are assumed to be released from the fuel pellet to the coolant during the event if fuel melting is predicted[14]. The threshold for fuel melting is assumed to be 4940 F (250 calories per gram at the fuel centerline) for all fuel rod burnups. This temperature is obtained by reducing the melting point suggested in Reference 14 (5150 F) to account for a maximum expected burnup of about 35,000 MWd/T. The radioactive gases in the fuel-cladding gap are assumed to be released if departure from nucleate boiling (DNB) is predicted to occur. The number of rods experiencing DNB is predicted using the method described above (Reference 13). For this event, fuel temperatures and DNB ratios (based on a closed-channel hydraulic model) are predicted with the STRIKIN-II code, using input from CESEC.

b. Coolable Core Geometry

Fuel geometry is maintained by providing continuous removal of decay heat. This guideline is met by limiting the extent of fuel melting and the duration of DNB prior to cooling the Reactor Coolant System to Mode 4. For the CEA ejection event, the radially averaged energy deposition at the hottest axial location is limited to a value less than 280 cal/gm[14] to prevent fuel rod dispersal due to the rapid reactivity insertion. After cooling to Mode 4, the coolable geometry guideline is met by preventing the fuel from exceeding the SAFDL on fuel temperature and the SAFDL on DNB. The analysis of all events has been taken to the point of showing decreasing fuel temperatures, increasing DNBR, and a sufficient coolant inventory to meet the guidelines stated herein.

15.0.4.4.4 DNBR Calculations NRC Questions Cycle 1

15.0.4.4.4.1 Question No. 440.11 (15.0)

The method that you have used for calculating the amount of failed fuel after an accident has not been approved. It is our position that fuel failures be recalculated using the criteria that any fuel rod which has a CE-1 DNBR less than the minimum DNBR value determined in Section 4.4 fails. Radiological consequences should be calculated accordingly.

<u>Response</u>

The Core Performance Branch has approved the methodology described in Subsection 15.0.4.4 for determining fuel failure and radioactive release from fuel rods. (Refer to Subsection 15.0.4.4.2(b) of Amendment No. 2, or Subsection 15.0.4.4.3(b) of a subsequent amendment.

15.0.4.4.4.2 Question No. 440.14 (15.0)

One of the key parameters in LOCA analyses is peak clad temperature. For non-LOCA transients, minimum DNBR (departure from nucleate boiling ratio) is of primary importance. For those transients analyzed in Section 15 of the FSAR, provide graphical output of the DNBR as a function of time.

Response

DNBR plots are provided for events which show a DNBR decreasing below its initial value for all sections of Chapter 15.

(15.1)	15.1.2.1	Figure 15.1.2.1-13
	15.1.4.3	Figure 15.1.4.3-9
	15.1.5.3	Figure 15.1.5.3-9
	15.1.6.3.3a	Figure 15.1.6-15
	15.1.6.3.3b	Figure 15.1.6-30
	15.1.6.3.3c	DNBR remains above 10
	15.1.6.3.3d	DNBR remains above 10

(15.2) No event or event combination addressed in Section 15.2 results in a minimum DNBR less than 1.19.

15.2.1.1	DNBR remains above 3.0.
15.2.1.2	No decrease in DNBR.
15.2.2.1	DNBR remains above 3.0.
15.2.2.2	Figure 15.2.2.2-12
15.2.3.2	Figure 15.2.3.2-12
15.2.5.2	Figure 15.2.5.2-21

(15.3) Events presented in Section 15.3 of the St. Lucie Unit 2 FSAR which initiate a decrease in reactor coolant pump flow rate are loss of offsite power (15.3.2.3), and one pump resistance to forced flow with a loss of offsite power as a result of turbine trip (15.3.4.3). Graphical output of DNBR versus time for the loss of offsite power event is presented as Figure 15.3.2.3-1 in the FSAR. For the one pump resistance to forced flow event with a loss of offsite power as a result of turbine trip, graphical output of DNBR versus time has been forwarded by the end of August, 1981 (See Subsection 15.3.5.1.5).

(15.4)	15.4.1.3	Figure 15.4.1.3-7
	15.4.2.3	Figure 15.4.2.3-7
	15.4.2.4	No decrease in DNBR
	15.4.3.1	Figure 15.4.3.1-8
	15.4.4.2	Minimum DNBR is greater than for 15.4.4.3
	15.4.4.3	Figure 15.4.4.3-2
	15.4.5.1	Figure 15.4.5.1-11
	15.4.5.3	Figure 15.4.5.1-11

(15.5) There are no events in 15.5 for which the DNBR decreases below the initial value.

(15.6) The events analysed in Section 15.6 of St. Lucie Unit 2 FSAR, which result in a decrease in the RCS inventory are steam generator tube rupture (15.6.2), letdown line

relief valve opening (15.6.3), letdown line relief valve opening with a high pre-existing iodine concentration (15.6.4), and letdown line break (15.6.5). Of these events, the steam generator tube rupture (15.6.2) was reanalyzed to include a loss of offsite power concurrent with a turbine trip. A graphical output of CE-1 DNBR as a function of time for this event.

For the events presented in Subsections 15.6.3 and 15.6.4, there is a loss of primary coolant through the letdown relief valve. The potential decrease in the RCS pressure from the loss of inventory is compensated by the Pressurizer Level Control System (PLCS) and the Pressurizer Pressure Control System (PPCS). Consequently, reactor performance parameters (core power, RCS pressure, core temperature, core flow) remain essentially constant throughout the transient. Therefore, the transient predicted CE-1 DNBR values remain essentially constant for both events.

For the letdown line break event (15.6.5) the RCS pressure decreases during the transient due to the inability of the PPCS and PLCS to compensate for the loss of primary coolant. The predicted CE-1 DNBR values also decrease during the transient until the operator takes manual action by tripping the reactor. A graphical representation of the CE-1 predicted DNBR values vs. time is presented in Figure 15.6.5.1-2. The minimum DNBR which occurs just prior to operator action (reactor trip) has a value of 1.62.

(15.7) Not applicable.

(15.8) There are no events in 15.8 for which the DNBR decreases below the initial value.

15.0.4.5 REFERENCES: (SECTIONS 15.0 THROUGH 15.0.4)

1. NRC Regulatory Guide 1.70, Revision 2, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," September 1975.

2. Standard Review Plans for Chapter 15L, U.S. NRC, NUREG-75/087, Rev. 01.

3. Deleted

4. Code of Federal Regulations, Part 100, "Reactor Site Criteria," U.S. NRC.

5. Transactions of the American Nuclear Society 1973 Winter Meeting, November 11-15, 1973, pp. 339-340.

6. CENPD-135P, “STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program,”
August 1974.

CENPD-135P, Supplement 2, “STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program (Modifications),” February 1975.

CENPD-135, Supplement 4-P, “STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program,” August 1976.

CENPD-135-P, Supplement 5, “STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program,” April 1977.

7. "CE Method for CEA Ejection Analysis," CENPD-190-A, July 1976, Proprietary Information.

8. "TORC Code - A Computer Code for Determining the Thermal Margin of a Reactor Core," CENPD-161-P, July 1975, Proprietary Information, CENPD-161-P-A, April 1986.

9. "TORC Code - Verification and Simplified Modeling Methods," CENPD-206-P, January 1977, Proprietary Information, CENPD-206-P-A, June 1981.

10. "COAST Code Description," CENPD-98, April 1973, Proprietary Information.

11. Caruthers, G. F., and Green, P. K., Radioactive Behavior in the Reactor Coolant System During Transient Operation, CE Topical Report, CENPD-180, March 1976, Proprietary Information.

12. Assumptions Used for Evaluating a Control Rod Ejection Accident for PWRs, Regulatory Guide 1.77, Appendix B, May, 1974.

13. "CE Method for Loss of Flow Analysis," CENPD-183, July 1975, Proprietary

Information, CENPD-183-A, June 1984

14. USNRC Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors," May 1974.

15. Deleted.

16. FPL letter L-79-287 from R. E. Uhrig (FPL) to H. R. Denton (NRC) dated October 8, 1979.

17. CE Setpoint Methodology, C-E Local Power Density and DNB LSSS and LCO Setpoint Methodology for Analog Protection Systems, CENPD-199-P Rev. 1- P, March 1982, CENPD-199-P, Rev. 1-P-A, January 1986.

18. Statistical Combination of Uncertainties, CEN-123(F)-P; Part 1, December 1979; Part 2, January 1980; Part 3, February 1980.

19. "CETOP-D Code Structure and Modeling Methods for Calvert Cliffs 1 and 2,"CEN-191(B)-P, December 1981.

20. CPC/CEAC Software Modifications for Arkansas Unit 2, CEN-143-A-P, Appendix A, December 1980.

21. McBeth, R. V., "An Appraisal of Forced Connection Burnout Data," Proc. Instn. Mech. Engrs., Vol. 180, Pt3C, PP 37-50, 1965-66.

22. Lee, D. H., "An Experimental Investigation of Forced Convection Burnout in High Pressure Water - Part 1V, Large Diameter Tubes at about 1600 psia," A.E.E.W. Report R 479, 1966.

23. "Extended Statistical Combination of Uncertainties," CEN-371(F)-P, July 1989.

15.0.5 ACCIDENT ANALYSES (CURRENT CYCLE)

Section 15.0.6 addresses the representative initiating events listed on pages 15-10, 15-11, and 15-12 of the USNRC Standard Format and Content Guide, Regulatory Guide 1.70, Revision 3 as they apply to St. Lucie Unit 2. Although the Standard Review Plan (NUREG-0800) does not form the licensing basis for St. Lucie Unit 2, Chapter 15 of NUREG-0800 has been used as a guide in development of the presentation of the information provided in this revision of the St. Lucie Unit 2 UFSAR.

15.0.6 CLASSIFICATION OF PLANT CONDITIONS

The American Nuclear Society (ANS) classification of plant conditions divides plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public (Reference 15.0-1). The four categories are used to define acceptance criteria and are defined as follows:

a. Condition I: Normal operation and operational transients

b. Condition II: Faults of moderate frequency

c. Condition III: Infrequent faults

d. Condition IV: Limiting faults

The basic principle applied in relating design requirements to each of the conditions is that the most probable occurrences should yield the least radiological risk to the public and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur. Functioning of the reactor trip system and engineered safeguards is assumed to the extent allowed by considerations such as the single failure criterion, in fulfilling this principle.

15.0.6.1 Condition I - Normal Operation and Operational Transients

Condition I occurrences are those which are expected frequently or regularly in the course of normal plant operation, refueling and maintenance. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Inasmuch as Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to adverse conditions which can occur during Condition I operation.

A typical list of Condition I events is listed below:

a. Steady-state and shutdown operations

   1. Power operation ($K_{eff} \geq 0.99$, > 5 percent of rated thermal power, $T_{avg} \geq 325°F$)

   2. Startup ($K_{eff} \geq 0.99$, ≤ 5 percent of rated thermal power, $T_{avg} \geq 325°F$)

   3. Hot standby ($K_{eff} < 0.99$, $T_{avg} \geq 325°F$, shut down cooling (SDC) system isolated)

4. Hot shutdown (K_{eff} < 0.99, 325°F > T_{avg} > 200°F, SDC system in operation)

5. Cold shutdown (K_{eff} < 0.99, T_{avg} ≤ 200°F, SDC system in operation)

6. Refueling (K_{eff} < 0.95, T_{avg} ≤ 140°F, SDC system in operation)

b. Operation with permissible deviations

Various deviations which may occur during continued operation as permitted by the plant technical specifications are considered in conjunction with other operational modes. These include:

1. Operation with components or systems out of service

2. Leakage from fuel with clad defects

3. Radioactivity in the reactor coolant

   a. Fission products

   b. Corrosion products

   c. Tritium

4. Operation with steam generator leaks up to the maximum allowed by the technical specifications

5. Testing as allowed by the technical specifications

c. Operational transients

1. Plant heatup and cooldown (up to 100°F/hr heatup for the RCS; 200°F/hr cooldown for the pressurizer)

2. Step load changes (up to ± 10 percent)

3. Ramp load changes (up to 5 percent/min)

4. Load rejection up to and including the design load rejection transient

15.0.6.2 Condition II - Faults of Moderate Frequency

ANS Condition II occurrences are faults that may occur with moderate frequency during the life of the plant. They are accommodated with, at most, a reactor shutdown with the plant being capable of returning to operation after a corrective action. In addition, no ANS Condition II occurrence shall cause consequential loss of function of fuel cladding and reactor coolant system barriers.

Criteria established for Condition II events include the following:

- Condition II incidents shall be accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.

- A single Condition II incident shall not cause consequential loss of the function of any barrier to the escape of radioactive products.
- For a Condition II event, any release of radioactive materials in effluents to unrestricted areas shall be in conformance with 10 CFR Part 20, “Standards for Protection Against Radiation”.
- By itself, a Condition II incident cannot generate a more serious incident of the Condition III or IV classification without other incidents occurring independently.

The following faults are typically included in this category as applicable:

a. Feedwater system malfunction causing a reduction in feedwater temperature

b. Feedwater system malfunction causing an increase in feedwater flow

c. Excessive increase in secondary steam flow

d. Inadvertent opening of a steam generator relief or safety valve

e. Loss of external load

f. Turbine trip

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

g. Deleted

i. Steam pressure regulator failure

j. Loss of non-emergency AC power to the station auxiliaries

k. Loss of normal feedwater flow

l. Transients resulting from the malfunction of one steam generator

m. Partial loss-of forced reactor coolant flow

n. Uncontrolled control element assembly (CEA) bank withdrawal from a subcritical or low power startup condition

o. Uncontrolled CEA bank withdrawal at power

p. CEA misoperation - dropped assembly, dropped assembly bank, or statically misaligned CEA

q. Startup of an inactive reactor coolant loop at an incorrect temperature

r. Chemical and volume control system (CVCS) malfunction that results in a decrease in boron concentration in the reactor coolant

s. Inadvertent operation of emergency core cooling system (ECCS) during power operation

t. CVCS malfunction that increases reactor coolant inventory

u. Inadvertent opening of a pressurizer safety or relief valve

v. Failure of small lines carrying primary coolant outside containment

15.0.6.3 Condition III - Infrequent Faults

ANS Condition III occurrences are faults that may occur very infrequently during the life of the plant. They may be accompanied by the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of the operation for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. An ANS Condition III occurrence will not, by itself, generate an ANS Condition IV fault or result in a consequential loss of function of the reactor coolant system or containment barriers.

Criteria established for Condition III events include the following:

- Condition III incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude resumption of operation for a considerable outage time.

- A Condition III incident shall not, by itself, result in a consequential loss of function of the reactor coolant system or reactor containment barriers

- A Condition III incident shall not, by itself, generate a Condition IV fault.

- The release of radioactive material due to Condition III incidents may exceed the guidelines of 10 CFR Part 20, “Standards for Protection Against Radiation,” but shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. This is typically interpreted as a small fraction of the applicable regulatory guidelines.

The following faults are typically included in this category as applicable:

a. Minor steam system piping failures

b. Complete loss of forced reactor coolant flow

c. CEA misoperation - single CEA withdrawal at full power

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

e. Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates the ECCS

f. Waste gas system failure

g. Radioactive liquid waste system leak or failure (atmospheric release)

h. Postulated radioactive releases due to liquid containing tank failure

i. Spent fuel cask drop accidents

15.0.6.4 Condition IV - Limiting Faults

ANS Condition IV occurrences are faults that are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. These are the most drastic occurrences that must be designed against and represent limiting design cases.

Criteria established for Condition IV events include the following:

- Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety exceeding the applicable regulatory guidelines.
- A single Condition IV fault shall not cause a consequential loss of required functions of systems needed to cope with the fault, including those of the reactor coolant system (RCS) and the reactor containment system.

The following faults are typically included in this category as applicable:

a. Major steam system piping failure
b. Feedwater system pipe break
c. Reactor coolant pump rotor seizure (locked rotor)
d. Reactor coolant pump shaft break
e. Spectrum of CEA ejection accidents
f. Steam generator tube rupture
g. Loss-of-coolant accidents (LOCA) resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary
h. Design basis fuel handling accident

For the Extended Power Uprate (EPU) analyses, the event classification of analyzed events was changed. Events are now classified as Anticipated Operational Occurrences (AOOs) or Postulated Accidents (PAs). An Event of Moderate Frequency and an Infrequent Event are considered AOOs and a Limiting Fault is considered a PAs. Although the event classifications have been updated, the acceptance criteria for each event remain the same. The event classification information can be found in:

- NUREG-0800, "Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants," Chapter 15, Revision 3, "Transient and Accident Analyses."

AOOs, as defined in Appendix A to 10 CFR Part 50, are those conditions of normal operation that are expected to occur one or more times during the life of the nuclear power plant.

The SRP uses the term AOO to refer to the events that are categorized in Regulatory Guide 1.70 and in Regulatory Guide 1.206 as incidents of moderate frequency (i.e., events that are expected to occur several times during the plant's lifetime) and infrequent events (i.e., events that may occur during the lifetime of the plant).

PAs are unanticipated occurrences (i.e., they are postulated but not expected to occur during the life of the nuclear power plant).

Analysis Acceptance Criteria for Anticipated Operational Occurrences

The following are the specific criteria necessary to meet the requirements of the General Design Criteria (GDC) for AOOs:

i. Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

ii. Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit for Pressurized Water Reactors(PWRs).

iii. An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Analysis Acceptance Criteria for Postulated Accidents

Unlike an AOO, a PA could result in sufficient damage to preclude resumption of plant operation. A list of the basic criteria necessary to meet the requirements of GDC for postulated accidents appears below. Individual sections of the SRP may specify additional criteria pertaining to certain postulated accidents.

i. Pressure in the reactor coolant system and main steam system should be maintained below 120% of the design values in accordance with the ASME Boiler and Pressure Vessel Code and consider potential brittle as well as ductile failures.

ii. Fuel cladding integrity will be maintained if the minimum DNBR remains above the 95/95 DNBR limit for PWRs. If the minimum DNBR does not meet this limit, then the fuel is assumed to have failed.

iii. The release of radioactive material shall not result in offsite doses in excess of the regulatory guidelines.

iv. A postulated accident shall not, by itself, cause a consequential loss of required functions of systems needed to cope with the fault, including those of the RCS and the reactor containment system.

For loss of coolant accidents (LOCAs), the following analysis acceptance criteria of 10 CFR 50.46 also apply:

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

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

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

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

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

15.0.7 PLANT CHARACTERISTICS AND INITIAL CONDITIONS ASSUMED IN THE ACCIDENT ANALYSES

15.0.7.1 Design Plant Conditions

Table 15.0-26 lists the principal power rating value that is assumed in the analyses performed in this report. The guaranteed NSSS-thermal power output includes the thermal power generated by the reactor coolant pumps and is consistent with the license application rating described in Chapter 1.

Allowances for errors in the determination of the steady-state power level are made as described in Section 15.0.7.2. The values used for each transient analyzed are given in Table 15.0-27 and Table 15.0-27a. The nominal values of pertinent plant parameters are given in Table 15.0-28 and Table 15.0-28a. EC287528

15.0.7.2 Initial Conditions

AREVA

See Section 15.0.20 EC287528

Westinghouse

For accidents that are departure from nucleate boiling (DNB) limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and included in the design limit DNB ratio (DNBR), as described in WCAP-11397 (Reference 15.0-2). This procedure is known as the "Revised Thermal Design Procedure," (RTDP).

For accidents which are not DNB limited, or in which the RTDP is not employed, the initial conditions are obtained by adding the maximum steady state errors to rated values. Table 15.0-27a summarizes initial conditions and computer codes used in the accident analyses and shows which accidents employed RTDP. EC287528

15.0.7.3 Power Distribution

AREVA

See Section 15.0.20 EC287528

Westinghouse

The transient response of the reactor system is dependent on the initial power distribution. Management of the reactor core design minimizes adverse power distribution through the placement of control rods and operating instructions. The power distribution may be characterized by the radial peaking factor (Fr), and the total peaking factor Fq (expressed in terms of peak linear heat rate). Peaking factor limits are given in the technical specifications.

For transients that may be DNB limited, the radial peaking factor is of importance. Fr increases with decreasing power level due to rod insertion. This increase in Fr is included in the core limits illustrated in Figure 15.0-3. All transients that may be DNB limited are assumed to begin with a Fr consistent with the initial power level defined in the technical specifications. The axial power shape used in the DNB calculation for Figure 15.0-3 is a 1.55 chopped cosine. The radial and axial power distributions described above are input to the VIPRE Code as described in Section 15.0.14.

For transients that may be overpower limited, the total peaking factor Fq is of importance. All transients that may be overpower limited are assumed to begin with power distributions that are consistent with reactor operation as defined in the technical specifications.

For overpower transients which are slow with respect to the fuel rod thermal time constant, fuel rod thermal evaluations are determined as discussed in Section 15.0.14. Examples of this are the uncontrolled boron dilution incident, which lasts many minutes, and the excessive load increase incident, which reaches equilibrium without causing a reactor trip. For overpower transients which are fast with respect to the fuel rod thermal time constant (for example, the uncontrolled CEA bank withdrawal from subcritical and CEA ejection incidents which result in a large power rise over a few seconds), a detailed fuel heat transfer calculation is performed. Although the fuel rod thermal time constant is a function of system conditions, fuel burnup and rod power, a typical value at beginning-of-life for high power rods is approximately 5 seconds.

15.0.8 REACTIVITY COEFFICIENTS ASSUMED IN THE ACCIDENT ANALYSES

The transient response of the reactor system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. The values used in the analysis of each event are given in Table 15.0-27a (Westinghouse). These reactivity coefficients are discussed in detail in Chapter 4. EC287528

In the analysis of certain events, conservatism requires the use of maximum reactivity coefficient values whereas in the analysis of other events, conservatism requires the use of minimum reactivity coefficient values. Some analyses, such as loss of reactor coolant from cracks or ruptures in the RCS, do not depend on reactivity feedback effects.

Figure 15.0-4 and Figure 15.0-4a show the upper and lower bound Doppler power coefficients as a function of power, used in the accident analysis. Figure 15.0-5 and Figure 15.0-5a show the maximum moderator temperature coefficient as a function of power level. The justification EC287528

for use of maximum versus minimum reactivity coefficient values is treated on an event-by-event basis. In some cases conservative combinations of parameters are used for a given transient to bound the effects of core life, although these may represent hypothetical combinations.

15.0.9 CONTROL ELEMENT ASSEMBLY INSERTION CHARACTERISTICS

The negative reactivity insertion following a reactor trip is a function of the position versus time of the control element assemblies (CEAs) and the variation in rod worth as a function of rod position. The CEA position versus time assumed in accident analyses is shown in Figure 15.0-6 and Figure 15.0-6a. Following a 0.74 second breaker opening delay, a CEA insertion time of 2.81 seconds is assumed in the safety analyses unless otherwise noted in the discussion of a specific event. The insertion times are specified in the plant technical specifications. EC287528

Figure 15.0-7 (Westinghouse) shows the fraction of total reactivity insertion versus normalized rod position for a core where the axial distribution is skewed to the lower region of the core. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to the point kinetics core models used in transient analyses. The bottom skewed power distribution itself is not an input into the point kinetics core model. There is inherent conservatism in the use of Figure 15.0-7 (Westinghouse) in that it is based on a skewed flux distribution which would exist relatively infrequently. EC287528 EC287528

A total negative reactivity insertion following a trip of 5.2 percent ΔK is assumed in the transient analyses except where specifically noted otherwise (Westinghouse). This assumption is conservative with respect to the calculated trip reactivity worth available. For Figure 15.0-6a, the CEA drop time is normalized to 2.81 seconds after accounting for a delay of 0.74 seconds. (Westinghouse) Figures 15.0-6a and 15.0-7 are used to define a conservative trip reactivity versus time relationship in those transient analyses for which a point kinetics core model is used. EC287528 EC287528

(Westinghouse) Where special analyses require use of three-dimensional or axial one-dimensional core models, the negative reactivity insertion resulting from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects. In this case, the CEA position versus time is based on Figure 15.0-6a. EC287528 EC287528

15.0.10 TRIP SETPOINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 15.0-29 and Table 15.0-29a. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are released. There are various instrumentation delays associated with each trip function including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. A reactor trip signal acts to open trip breakers that removes power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the CEAs which then fall by gravity into the core. EC287528

AREVA EC287528

See Section 15.0.20

Westinghouse

EC287528

Figure 15.0-3 presents the relationship between the core thermal limits and selected protection functions. The core thermal limits are provided as reactor pressure vessel inlet temperatures for the design flow and reference power distribution (1.55 chopped cosine) for limiting pressurizer pressures and the nominal operating pressure value. The area of permissible operation (power, pressure, and temperature) is bounded by the combination of reactor trips: high pressurizer pressure (fixed setpoint); low pressurizer pressure (TM/LP floor/fixed setpoint); TM/LP (variable setpoints); Variable High Power Trip (ceiling/fixed setpoint), and by a line defining conditions at which the steam generator safety valves open. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions trip would occur well within the area bounded by these lines.

The utility of this diagram is that the limit imposed by any given DNBR can be represented as a series of lines. The core thermal limit lines represent the locus of conditions for which DNBR equals the limit value and ensures that vessel exit boiling is precluded to ensure that ΔT remains a function of power. All points below and to the left of the core thermal limits for a given pressure have a DNBR greater than the limit value. The diagram shows that DNB is prevented for all cases based on the reference power shape if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line.

The limit value, which was used as the DNBR limit for all accidents analyzed with RTDP, is conservative compared to the actual design DNBR value required to meet the DNB design basis.

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant technical specifications. During plant startup tests it is demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, protection system channels are calibrated and instrument response times determined periodically in accordance with the plant technical specifications.

15.0.11 PLANT SYSTEMS AND COMPONENTS AVAILABLE FOR MITIGATION OF ACCIDENT EFFECTS

The plant is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions and dynamic effects of the postulated accidents. In addition, the design incorporates features which minimize the probability and effects of fires and explosions. Chapter 17 discusses the quality assurance program which has been implemented to assure that the plant will be designed, constructed, and operated without undue risk to public health and safety. The incorporation of these features in the plant, coupled with the reliability of the design, ensures that the normally operating systems and components listed in Table 15.0-30 will be available for mitigation of the events discussed in Chapter 15. In determining which systems are necessary to mitigate the effects of these postulated events, the classification system of ANSI-N18.2-1973 is utilized.

In the analysis of Chapter 15 events, control system action is considered only if that action results in more severe consequences. No credit is taken for control system operation if that operation mitigates the results of an accident. For some accidents, the analysis is performed both with and without control system operation to determine the worst case.

15.0.12 FISSION PRODUCT INVENTORIES

15.0.12.1 Primary Coolant Source Term

The primary coolant source term is located in Table 15.0-32.

15.0.13 RESIDUAL DECAY HEAT

15.0.13.1 Total Residual Decay Heat

Residual heat in a subcritical core is calculated in accordance with the requirements of Paragraph (1)(A)(4) of Appendix K to 10 CFR 50 for large-break LOCA and small-break LOCA. These requirements include assuming infinite irradiation time before the core goes subcritical to determine fission product decay energy.

AREVA

For RLBLOCA, the decay heat model used in S-RELAP5 is the built-in ANS 1979 decay heat model with one fissle isotope (U-235) and the equilibrium decay heat precursor concentrations based on infinite operation with a deterministic approach for the decay heat curve used in the analysis. EC287528

The non-LOCA decay heat model is the ANS73 correlation with actinides based on infinite operation.

Westinghouse

The decay heat model used in RETRAN is the built-in ANS-1979 decay heat model with one fissile isotope (U-235) and the equilibrium decay heat precursor concentrations based on infinite operation. A decay heat multiplier is used to bound the maximum decay heat levels, including a 2-sigma uncertainty, for region average burnups of up to 70 GWD/MTU, enrichments up to 5%, over the time interval zero to 10,000 seconds following reactor trip. For some analyses, decay heat is a benefit and may be conservatively removed by using a very small decay heat multiplier.

15.0.14 COMPUTER CODES UTILIZED

Summaries of the principal computer codes used in the transient analyses are given below. Other codes, in particular very specialized codes in which the modeling has been developed to simulate specific events, such as the LOCA evaluation model (see Section 15.6), are summarized in their respective sections of the UFSAR. The codes used in the analyses of each transient have been listed in Table 15.0-27.

15.0.14.1 FACTRAN (Westinghouse) EC287528

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

a. A sufficiently large number of radial space increments to handle fast transients such as rod ejection accidents.

b. Material properties which are functions of temperature and a sophisticated fuel-to-clad gap heat transfer calculation.

c. The necessary calculations to handle post DNB transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel.

FACTRAN is further discussed in Reference 15.0-4.

15.0.14.2 RETRAN (Westinghouse) EC287528

RETRAN is a one-dimensional, best-estimate, thermal-hydraulic transient analysis computer code developed under the sponsorship of the Electric Power Research Institute to provide a thermal-hydraulic code which could be used for analysis of light water reactor systems. The RETRAN code is a variable nodalization code; therefore, the user builds the desired plant model by defining the control volumes and flow paths (i.e., junctions) with heat slabs (i.e., conductors) to account for heat transfer in both the primary and secondary system elements.

The RETRAN code allows either point neutron kinetics or one dimensional space time kinetics to be used for the neutronics. Various component models are available, including a two-region nonequilibrium pressurizer, centrifugal pumps, valves, and non-conduction heat exchangers. In addition, special purpose models include a subcooled void fit, bubble rise, trips, and a flexible control system which allows the user to implement a wide range of auxiliary calculations/systems.

RETRAN is further discussed in References 15.0-5 and 15.0-6.

15.0.14.3 TWINKLE (Westinghouse) EC287528

The TWINKLE program is a multi-dimensional spatial neutron kinetics code which was patterned after steady-state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multiregion fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 8000 spatial points and performs its own steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits are provided; e.g., channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, and fuel temperatures.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in Reference 15.0-7.

15.0.14.4 CESEC (Westinghouse) EC287528

The CESEC digital computer program provides for the simulation of a Combustion Engineering (CE) Nuclear Steam Supply System (NSSS). The program can calculate the plant response for non-LOCA initiating events for a wide range of operating conditions.

The primary system components considered in the code include the reactor vessel, the reactor core, the primary coolant loops, the pressurizer, the steam generators, and the reactor coolant pumps. The secondary system components include the secondary side of the steam generators, the main steam system, the feedwater system, and the various steam control valves. In addition, the program models those plant control and protections systems needed to perform the analysis.

CESEC is further described in Reference 15.0-8.

15.0.14.5 VIPRE (Westinghouse) EC287528

The VIPRE code is described in Reference 15.0-21.

15.0.14.6 ANC (Westinghouse) EC287528

The ANC code is described in Reference 15.0-22.

15.0.14.7 ARCON96

ARCON96 is used to calculate relative concentrations (χ/Q factors) in plumes from nuclear power plants at control room intakes in the vicinity of the release point using plant meteorological data. ARCON96 is further described in Reference 15.0-9.

15.0.14.8 MicroShield

MicroShield is used to analyze shielding and estimate exposure from gamma radiation. MicroShield is described in Reference 15.0-10.

15.0.14.9 ORIGEN

ORIGEN is a nodal code used for calculating the buildup, decay, and processing of radioactive materials.

ORIGEN is described in Reference 15.0-11.

15.0.14.10 PAVAN

PAVAN provides relative air concentration (χ/Q) values as functions of direction for various time periods at the EAB and LPZ boundaries assuming ground-level releases or elevated releases from freestanding stacks.

PAVAN is described in Reference 15.0-12.

15.0.14.11 RADTRAD-NAI

RADTRAD estimates the radiological doses at offsite locations and in the control room of nuclear power plants as consequences of postulated accidents. The code considers the timing, physical form (i.e., vapor or aerosol) and chemical species of the radioactive material released into the environment. RADTRAD-NAI began with versions 3.01 and 3.02 of the NRC's RADTRAD computer code, originally developed by Sandia National Laboratory (SNL). The code is initially modified to compile on a UNIX system. Once compiled, an extensive design review/verification and validation process began on the code and documentation. The subject of the review also included the source code for the solver, which is made available in a separate distribution from the NRC. The dose conversion factors used by RADTRAD-NAI are from Federal Guidance Report Nos. 11 and 12 (Reference 15.0-17 and 15.0-18). RADTRAD-NAI is developed and is maintained under Numerical Applications' 10 CFR 50 Appendix B program.

RADTRAD is further described in Reference 15.0-13.

15.0.14.12 S-RELAP5 AREVA

The S-RELAP5 code is an AREVA modification of the RELAP5/MOD2 code. S-RELAP5 was used for simulation of the transient system response to accidents. Control volumes and junctions are defined which describe the major components in the primary and secondary systems that are important for the event being analyzed. The S-RELAP5 hydrodynamic model is a two-dimensional, transient, two-fluid model for flow of a two-phase steam-water mixture. S-RELAP5 uses a six-equation model for the hydraulic solutions. These equations include two-phase continuity equations, two-phase momentum equations, and two-phase energy equations. The six-equation model also allows both non -homogeneous and non-equilibrium situations encountered in reactor problems to be modeled.

15.0.14.13 RODEX2 (AREVA)

RODEX2 performs thermal-mechanical calculations for a fuel rod under normal operating conditions. The code incorporates models to describe the thermal-hydraulic condition of the fuel rod in a flow channel; the gas release, swelling, densification and cracking in the pellet; the gap conductance; the radial thermal conduction; the free volume and gas pressure internal to the fuel rod; the fuel and cladding deformations; and the cladding corrosion. The code has been extensively benchmarked and its predictive capabilities were correlated over a wide range of conditions applicable to light water reactor fuel conditions. RODEX2 was used to establish the fuel centerline melt LHR as a function of exposure. A penalty to address TCD was applied where applicable. EC287528

15.0.14.14 COPERNIC (AREVA)

COPERNIC performs thermal-mechanical calculations for a fuel rod under normal operating conditions. The code incorporates models to describe the thermal-hydraulic condition of the fuel rod in a flow channel; the gas release, swelling, densification and cracking in the pellet; the gap conductance; the radial thermal conduction; the free volume and gas pressure internal to the fuel rod; the fuel and cladding deformations; and the cladding corrosion. The code has been extensively benchmarked and its predictive capabilities were correlated over a wide range of conditions applicable to light water reactor fuel conditions.

However, COPERNIC accounts for TCD with increasing rod exposure whereas RODEX2 does not. To account for the effects of TCD in the S-RELAP5 simulations, COPERNIC was used to generate the fuel thermal-conductivity, heat capacity and fuel pellet-to-clad gap coefficient inputs for the average core and hot spot models. The properties from COPERNIC were developed in accordance with Reference 15.0-23, and COPERNIC replaces RODEX2 for this purpose in the approved topical report. The COPERNIC fuel properties and gap coefficients were conservatively implemented relative to the RODEX2 inputs as approved in Reference 15.0-23. Average core and hot spot fuel properties and gap coefficients were conservatively calculated for $U0_2$ and Gd_2-O_3 bearing fuel rods at BOC and EOC.

15.0.14.15 XCOBRA-IIIC (AREVA)

The XCOBRA-IIIC code (Reference 15.0-24) is a steady-state thermal-hydraulics code that calculates the axial and radial flow and enthalpy distributions within assemblies and sub-channels for non-LOCA events. When used in conjunction with core boundary conditions from the S-RELAP transient analysis and the HTP DNB correlation (Reference 15.0-25), XCOBRAIIIC also calculates the corresponding MDNBR. MDNBR calculations are performed in a two-step process. Calculations are first performed on a core-wide basis to calculate the axially varying flow and enthalpy distributions in the peak powered fuel assembly. Next, these flow and enthalpy boundary conditions are applied to a sub-channel model of the peak powered assembly to determine the local conditions for the calculation of MDNBR. EC287528

The Biasi correlation (Reference 15.0-26) was used with XCOBRA-IIIC for the post-scram MSLB analysis as approved in Reference 15.0-23.

15.0.14.16 PRISM (AREVA)

AREVA's Pressurized Water Reactor (PWR) neutronics methodology uses the NRC-approved advanced nodal simulator code system SAV95. SAV95 is built around the assembly spectrum/depletion code system MICBURN-3/CASMO-3 developed by Studsvik Scandpower and the three-dimensional reactor code PRISM. PRISM is a three-dimensional, coarse-mesh reactor simulator using two-group diffusion theory. The simulator code models the reactor core in three-dimensional (X-Y-Z) geometry, and the reactor calculations can be performed in quarter- or full-core geometry. The code calculates the reactor core reactivity, nodal power distribution, pin power distribution, and in-core detector responses and can be used to simulate fuel shuffling, insertion, and discharge. A summary of the key validation results for the SAV95 code system is presented in Reference 15.0-27.

15.0.15 RADIOLOGICAL CONSEQUENCES

This section describes the dose consequences analysis approach for the Chapter 15 events performed using the Alternative Source Term (AST) methodology. The applicable events for Unit 2 are listed below. These accidents follow the guidelines of Regulatory Guide 1.183. Other accidents follow 10 CFR 100 guidelines as described in Section 15.0.15.2.

St. Lucie Unit 2 Events Analyzed Using the AST Methodology

LOCA
Steam System Piping Failures
Steam Generator Tube Rupture
Control Element Assembly Ejection

Reactor Coolant Pump Shaft Seizure
Fuel Handling Accident
Feedwater Line Break
Letdown Line Break
Waste Gas Decay Tank Failure Station Black Out

15.0.15.1 Alternative Source Term (AST) Methodology

15.0.15.1.1 Introduction

The analysis of radiological consequences with AST is performed in accordance with the requirements of 10 CFR 50.67. Advances made in understanding the timing, magnitude, and chemical form of fission product releases from severe nuclear power plant accidents are used to revise the traditional accident source term used in the design basis accident radiological consequence analyses with alternative source term (AST). Per the requirements of Part 50.67, an evaluation of the consequences of the affected design basis accidents is included in this Chapter. Regulatory guidance for the implementation of the AST is provided in Regulatory Guide (RG) 1.183 (Reference 15.0-14).

As documented in Nuclear Energy Institute (NEI) guidance document, NEI 99-03 (Reference 15.0-15), several nuclear plants performed testing on control room unfiltered air inleakage that demonstrated leakage rates in excess of amounts assumed in the accident analyses. The AST methodology as established in RG 1.183 is used to calculate the offsite and control room radiological consequences for St. Lucie Unit 2 to support the control room habitability program by addressing the radiological impact of potential increases in control room unfiltered air inleakage.

As part of the implementation of AST, the total effective dose equivalent (TEDE) acceptance criterion of 10 CFR 50.67(b)(2) replaces the previous whole body and thyroid dose guidelines of 10 CFR 100.11. As part of the implementation of AST, the following changes are assumed in the analysis:

a. The total effective dose equivalent (TEDE) acceptance criterion of 10 CFR 50.67(b)(2) replaces the previous whole body and thyroid dose guidelines of 10 CFR 100.11.

b. New onsite (Control Room) and offsite atmospheric dispersion factors are developed.

c. Increased values for control room unfiltered air inleakage are assumed.

d. The primary-to-secondary leakage used in the analysis is 0.5 gpm through all steam generators and 0.25 gpm through any one steam generator at accident conditions. The primary-to-secondary leakage limit in the Technical Specification has been changed to 150 gallons per day through any one steam generator (SG) at room temperature.

Accident Source Term

The full core isotopic inventory for St. Lucie Unit 2 is determined in accordance with RG 1.183. The inventory of fission products in the core and coolant systems that is available for release to

the containment is based on the maximum full power operation of the core and the fuel enrichment 1.5 to 5.0 w/o, and fuel burnup up to 49,000 mwd/mtu. Event-specific isotopic source terms are developed using a bounding approach. The maximum core power of 3030 MW_{th} is calculated as the current licensed rated thermal power of 3020 MW_{th} plus the ECCS evaluation uncertainty of 0.3%. The period of irradiation is selected to be of sufficient duration to allow the activity of dose-significant radionuclides to reach equilibrium or to reach maximum values.

The nominal primary coolant activity is based on 1% failed fuel. The iodine activities are adjusted to achieve the TS limit of 1.0 μCi/gm dose equivalent I-131 using the TS definition of Dose Equivalent I-131 (DE I-131) and dose conversion factors for individual isotopes from Federal Guidance Report II, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion.” The remaining (non-iodine) isotopes are adjusted to achieve the TS limit of 518.9 μCi/gm DE Xe-133.

Secondary system coolant activity is limited to a value of ≤ 0.10 μCi/gm dose equivalent I-131 in accordance with the TS. Noble gases entering the secondary system coolant are assumed to be immediately released; thus the noble gas activity concentration in the secondary system coolant is assumed to be 0.0 μCi/gm. Thus, the secondary side iodine activity is 1/10 of the primary coolant activity.

Assumptions and Methodologies

The AST analyses use assumptions and models defined in RG 1.183 to provide appropriate and prudent safety margins. The AST analyses apply TEDE acceptance criteria.

Except as otherwise stated, credit is taken for engineered safety features (ESF) and other appropriately qualified, safety-related, accident mitigation features. Selected numeric input values are conservative to assure a conservative calculated dose. Except as otherwise required by regulatory guidance, analyses use current licensing basis values.

Meteorological data collected by the St. Lucie site meteorological monitoring program described in the UFSAR is used in generating the accident atmospheric dispersion (χ/Q) factors.

15.0.15.2 Non-LOCA Dose Analysis

15.0.15.2.1 Introduction

This section describes the dose consequences analysis used in the Non-LOCA Dose analyses. The radiological consequences analyses for LOCA (Loss of Coolant Accidents) are addressed in Subsections 6.3.3 and 15.6.5. All events are analyzed or evaluated to assure that they meet their respective criterion.

15.0.15.2.2 Method of Analysis

Table 15.0-33 presents the events which were analyzed with respect to the offsite dose criterion. Acceptance guidelines on offsite radiation dose have been established based on 10 CFR 100 and Regulatory Guide 1.183 criteria. The offsite dose acceptance guidelines for Limiting Faults correspond to those suggested for accidents by the Standard Review Plans. The guidelines as a function of frequency are specified in Table 15.0-4.

The radiological consequences for the feedwater line break analysis were applied to the Anticipated Operational Occurrences as a means of bounding the results. This approach is valid since the feedwater line break analysis does not involve fuel failure, the assumptions used in the feedwater line break evaluation conservatively apply to the AOOs.

Based on parametric studies that were performed for certain events (e.g., steam system piping failures), several combinations of input parameters (e.g., break size and moderator temperature coefficient) result in limiting fuel failures. For these events, the parameter trends of power, temperature and pressure in the cases presented are viewed as representative. For events that are predicted to have fuel failures, acceptable values for fuel failure were back calculated from the dose acceptance limits. These back calculated values of fuel failure will be verified as bounding and applicable to a particular reload core via cycle specific analysis. The iodine dose conversion factors used in the safety analysis are those listed in Federal Guidance Report 11. Doses that use TID-14844 remain bounding as reliance on the dose conversion factors from TID-14844 will continue to yield conservative results relative to use of Federal Guidance Report 11 (all other inputs being equal).

Starting with Cycle 15, the Non-LOCA safety analyses transitioned from the CESEC based Combustion Engineering analytical processes to the RETRAN based WCAP-9272 (Reference 15.0-20) analytical process. For Non-LOCA fuel failure events, the dose consequences are dominated by the amount of fuel failures and the primary-to-secondary leakage.

15.0.16 LIMITING SINGLE FAILURES

The most limiting single failure of safety-related equipment, where one exists, is identified in each analysis description, and the consequences of this failure are described therein. In some instances, because of redundancy in protection equipment, no single failure which could adversely affect the consequences of the transient has been identified. The failure assumed in each analysis is listed in Table 15.0-31.

15.0.17 OPERATOR ACTIONS

For most of the events analyzed in Chapter 15 the plant will be in a safe and stable hot standby condition following the automatic actuation of reactor trip. This condition will, in fact, be similar to plant conditions following any normal, orderly shutdown of the reactor. At this point, the actions taken by the operator would be no different than normal operating procedures. The exact actions taken, and the time at which these actions would occur, will depend on what systems are available (e.g., turbine bypass system, main feedwater system, etc.) and the plans for further plant operation. As a minimum, to maintain the hot stabilized condition, decay heat must be removed via the steam generators. The main feedwater system and the steam dump or atmospheric relief system could be used for this purpose. Alternatively, the auxiliary feedwater system and the steam generator safety valves may be used, both of which are safety grade systems.

Instrumentation and controls provided to allow the operator to complete required manual actions are classified as Class 1E. Electrical components are also classified as Class 1E. Mechanical components are classified as Safety Class 1, 2, or 3. Safety systems required for accident mitigation are designed to function after the occurrence of the worst postulated single failure. There are no adverse impacts as a result of these actions.

In general, the safety analyses do not credit operator action unless specially noted. The minimum delay time assumed depends on the event frequency (to account for expected operator experience) and relative complexity of action.

15.0.18 DELETED

15.0.19 EFFECT OF EXTENDED POWER UPRATE IMPLEMENTATION

All accident analyses presented in Chapter 15 of the St. Lucie Unit 2 UFSAR were evaluated to determine the impact of the Extended Power Uprate (EPU). The Westinghouse analyses consider, where appropriate, average tube plugging up to and including 10%, with an asymmetry of +/- 2%.

For each event, the pertinent key plant parameters that affect the calculated approach to the acceptance criteria were identified and compared to determine any changes between the pre-EPU and post-EPU conditions. Once the applicable parameter differences were identified for each event, an evaluation was performed to verify either that the analysis of record in the UFSAR bounds the St. Lucie Unit 2 response at EPU conditions or that the plant response would meet all acceptance criteria following the EPU implementation. It was determined that most of the events needed to be analyzed for EPU conditions. Each of these events was analyzed with all safety system actuation setpoints and initial conditions, as listed in this section, consistent with EPU implementation.

It was determined from the parameter evaluations that the following events have a potential to challenge some of the acceptance criteria.

15.1.1 - Decrease in Feedwater Temperature
15.1.2 - Increase in Feedwater Flow
15.1.3 - Excessive Load Increase
15.1.4 - Inadvertent Opening of a Steam Generator Relief or Safety Valve
15.1.5 - Pre-Trip Steam System Piping Failure
15.1.6 - Post-Trip Steam System Piping Failure
15.2.3 - Loss of Condenser Vacuum
15.2.8 - Feedwater System Pipe Breaks
15.2.9 - Transients Resulting from the Malfunction of One Steam Generator
15.3.1 - Partial Loss of Forced Reactor Coolant Flow
15.3.2 - Complete Loss of Forced Reactor Coolant Flow
15.3.3 - Reactor Coolant Pump Rotor Seizure
15.4.1 - Uncontrolled CEA Withdrawal from a Subcritical or Low Power Startup Condition
15.4.2 - Uncontrolled CEA Withdrawal at Power
15.4.3 - Control Element Assembly Misoperation
15.4.6 - CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant
15.4.8 - Spectrum of Control Element Assembly Ejection Accidents
15.5.2 - CVCS Malfunction That Increases Reactor Coolant Inventory
15.6.1 - Inadvertent Opening of a Pressurizer Safety or Relief Valve
15.6.2 - Break in Instrument Line of Other Lines from the Reactor Coolant Pressure Boundary that Penetrate the Containment
15.6.3 - Steam Generator Tube Rupture

Confirmatory analyses were performed for each of the aforementioned events. The acceptance criteria for each event remain satisfied for operation at EPU conditions and are documented in the subsequent Chapter 15 sections of UFSAR.

15.0.20 EFFECT OF AREVA FUEL TRANSITION IMPLEMENTATION

General

All accident analyses presented in Chapter 15 of the St. Lucie Unit 2 UFSAR were evaluated to determine which events needed to be analyzed for the Transition to AREVA Fuel. Each event is categorized with respect to its potential consequences. The events fall into two principle classifications: anticipated operational occurrence (AOO) and postulated accident (PA). Where applicable, the RPS and/or ESF were assumed to fulfill their functions, as needed, to mitigate the consequences of a given event. EC287528

For the fuel transition, detailed analyses were performed for the events that potentially challenge the fuel related acceptance criteria (e.g., minimum DNBR and fuel centerline melt), as well as event specific criteria (time-to-criticality for Boron Dilution and deposited enthalpy for CEA Ejection).

Several St. Lucie Unit 2 UFSAR Chapter 15 events are affected by the transition to AREVA CE-16 HTP™ fuel, specifically because of changes in thermal-hydraulic performance and fuel design limits to the safety analyses. On the other hand, events and/or sub-events whose key parameters are plant related system responses, e.g., core power, decay heat, auxiliary feedwater (AFW) capability, offsite power availability, safety injection and/or charging capability, safety valve performance, etc., rather than the fuel design parameters, were not analyzed for the fuel transition. The AREVA analyses consider, where appropriate, average tube plugging up to and including 20%, with an asymmetry of +/-4%. EC287528

The acceptance criteria for each event remain satisfied for operation with AREVA Fuel and are documented in the subsequent Chapter 15 sections of UFSAR.

AREVA Thermal Hydraulic Analyses

The preceding sections in Chapter 15.0 are not necessarily applicable to AREVA fuel; however, they have been left in this document for historical purposes. For a description of the thermal and hydraulic design of the reactor, refer to Section 4.4. A detailed description of each event, including results from thermal and hydraulic analyses, is provided in subsequent sections.

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TABLE 15.0-1

EVENT GROUPS AND INITIATING EVENTS

A. Increased Heat Removal by Secondary System

A1. Increase Feedwater Flow
- Opening a main feedwater control valve above feed requirements
- Opening a main feedwater bypass valve above feed requirements
- Misoperation of feedwater heater drain system which increases FW flow
- Increased auxiliary feedwater pump speed
- Opening an auxiliary feedwater control valve above requirements
- Opening all auxiliary feedwater control valves above requirements
- Opening all main feedwater control valves above requirements

A2. Increased Main Steam Flow-Through Turbine
- Opening a turbine control valve above load requirements
- Opening a turbine control or stop valves above load requirements

A3. Increased Main Steam Flow-Through Bypass or Dump
- Opening a turbine bypass valve
- Opening a steam dump valve

A4. Increased Main Steam Flow-Through ADV or MSSV
- Opening a main steam safety valve (MSSV)
- Opening an atmospheric dump valve (ADV)

A5. Decreased Feedwater Enthalpy
- Loss or reduction of extraction steam flow to a feedwater heater

A6. Loss of Main Steam-Small, Inside Containment
- Partial break in 34/36 inch main steam line
- Break in pipe less than 34/36 inches in diameter

A7. Loss of Main Steam-Small, Outside Containment, Upstream of Main Steam Isolation Valve
- Partial break in 35.5 inch main steam line
- Partial break in 10 inch ADV inlet line
- Partial break in 6 inch MSSV inlet line
- Break in a pipe less than 6 inches in diameter

A8. Loss of Main Steam-Small, Outside Containment, Downstream of Main Steam Isolation Valve
- Partial break in 40 inch main steam header
- Partial break in 38 inch main steam line
- Partial break in 26 inch main turbine inlet line
- Partial break in 20 inch turbine bypass Moisture Separator Re-heater header
- Break in a pipe less than 20 inches in diameter

A9. Loss of Main Steam-Large, Inside Containment
- Break in 34/36 inch main steam line

A10. Loss of Main Steam-Large, Outside Containment, Upstream of Main Steam Isolation Valve
- Break in 35.5 inch main steam line
- Break in 10 inch ADV inlet line
- Break in 6 inch MSSV inlet line
- Break in a pipe less than 6 inches in diameter

TABLE 15.0-1 (Cont'd)

A11. Loss of Main Steam-Large, Outside Containment, Downstream of Main Steam Isolation Valve
- Break in 40 inch main steam header
- Break in 38 inch main steam line
- Break in 20 inch turbine bypass or moisture separator reheater header
- Break in a pipe less than 20 inches in diameter

B. Decreased Heat Removal by Secondary System

B1. Loss of External Load
- Opening main transformer output circuit breaker to grid
- Loss of the main transformer
- Loss of a unit auxiliary transformer
- Loss of the main transformer feeder
- Loss of a unit auxiliary transformer feeder

B2. Decreased Main Steam Flow-Downstream of Header
- Closure of a turbine control or stop valve
- Partial closure of a turbine control or stop valve
- Partial closure of turbine control or stop valves (less than bypass capacity)
- Closure of a turbine intercept valve
- Partial closure of turbine intercept valves
- Partial closure of a turbine intercept valve
- Closure of turbine intercept valves
- Closure of reheat stop valves
- Closure of turbine bypass and/or steam dump valve(s)

B3. Decreased Main Steam Flow-Upstream of Header
- Closure of a main steam isolation valve
- Partial closure of a main steam isolation valve

B4. Isolation of Turbine
- Closure of all turbine control and/or stop valves

B5. Termination of Main Steam Flow
- Closure of all main steam isolation valves

B6. Partial Loss of Normal Feedwater Flow
- Partial closure of a main feedwater isolation valve
- Partial closure of a main feedwater control valve
- Reduced main feedwater pump speed
- Low main feedwater pump discharge flow
- Loss of a main feedwater pump
- Partial closure of a main feedwater bypass valve
- Partial closure of all main feedwater control valves
- Reduced auxiliary feedwater pump speed
- Low auxiliary feedwater pump discharge flow
- Partial closure of an auxiliary feedwater control valve
- Partial closure of auxiliary feedwater control valves
- Recirculation of main feedwater
- Partial closure of a main feedwater pump discharge isolation valve
- Closure of a main feedwater pump discharge isolation valve

TABLE 15.0-1 (Cont'd)

B7. Total Loss of Normal Feedwater Flow - To a Steam Generator
- Closure of a main feedwater isolation valve
- Closure of a main feedwater control valve
- Closure of a main feedwater bypass valve
- Loss of an auxiliary feedwater pump
- Closure of an auxiliary feedwater control valve

B8. Total Loss of Normal Feedwater Flow - To Both Steam Generators
- Loss of all main feedwater pumps
- Closure of all main feedwater control valves
- Closure of auxiliary feedwater control valves

B9. Loss of Feedwater Inventory-Small, Inside Containment, Upstream of Check Valve
- Partial break in 20 inch main feedwater line
- Break in a pipe less than 20 inches in diameter

B10. Loss of Feedwater Inventory-Small, Outside Containment, Downstream of Main FW Isolation Valve
- Partial break in 20 inch main feedwater line
- Partial break in 8 inch auxiliary feedwater suction line
- Partial break in 6 inch auxiliary feedwater discharge line
- Break in a pipe less than 6 inches in diameter

B11. Loss of Feedwater Inventory-Small, Outside Containment, Upsteam of Main FW Isolation Valve
- Partial break in 26 inch main feedwater header
- Partial break in 20 inch main feedwater line
- Partial break in 18 inch HP feedwater heater bypass line
- Break in a pipe less than 18 inches in diameter

B12. Loss of Feedwater Inventory-Large, Inside Containment, Upstream of Check Valve
- Break in 20 inch main feedwater line

B13. Loss of Feedwater Inventory-Large, Outside Containment, Downstream of Main FW Isolation Valve
- Break in 20 inch main feedwater line
- Break in 8 inch auxiliary feedwater suction line
- Break in 6 inch auxiliary feedwater discharge line
- Break in a pipe less than 6 inches in diameter

B14. Loss of Feedwater Inventory-Large, Outside Containment, Upstream of Main FW Isolation Valve
- Break in 26 inch main feedwater header
- Break in 20 inch main feedwater line
- Break in 18 inch HP feedwater heater bypass line
- Break in a pipe less than 18 inches in diameter

B15. Loss of Feedwater Inventory-Small, Inside Containment, Downstream of Check Valve
- Partial break in 18 inch main feedwater line

B16. Loss of Feedwater Inventory-Large, Inside Containment, Downstream of Check Valve
- Break in 18 inch main feedwater line

B17. Loss of Normal Power to Half of the Plant
- Opening a startup transformer supply circuit breaker
- Loss of a startup transformer
- Loss of a startup transformer feeder

TABLE 15.0-1 (Cont'd)

B18. Loss of Condenser Vacuum
- Loss of a circulating water pump
- Loss of circulating water pumps
- Low circulating water pump discharge flow
- Loss of air ejector(s)
- Air leakage in excess of air ejector capacity
- Failure of a low pressure turbine rupture disc
- Loss of turbine gland sealing system

B19. Loss of Instrument Air
- Break in air line - downstream of backup supply discharge nozzle
- Loss of a compressor
- Loss of compressors
- Reduction of air dryer pressure
- Reduction of air receiver (accumulator) pressure
- Blockage of air line - downstream of backup supply discharge nozzle
- Reduction of compressor pressure

B20. Loss of Condenser Vacuum and Partial Loss of Normal Power to Safety loads
- Loss of non-safety 4.16 kV bus

B21. Partial Loss of Power to ESF loads
- Loss of a safety 4.16 kV bus

B22. Partial Loss of DC Power
- Loss of a 125V DC bus

B23. Increased Feedwater Enthalpy
- Increased extraction steam flow to feedwater heater(s)

C. Decrease in Reactor Coolant Flow

C1. One Reactor Coolant Pump Loss of Forced Flow
- Opening a reactor coolant pump power supply circuit breaker
- Interruption of reactor coolant pump electric power

C2. One Reactor Coolant Pump Resistance to Forced Flow
- Loss of reactor coolant pump lube oil flow

C3. Reduction of Forced Flow-Shaft Shear
- Sheared reactor coolant pump shaft

C4. Partial Loss of Shutdown Cooling Flow
- Closure of a shutdown cooling discharge isolation valve
- Closure of a shutdown cooling suction isolation valve
- Closure of a shutdown cooling stop valve
- Loss of a shutdown cooling pump
- Opening a cross-over return valve
- Closure of a shutdown cooling heat exchanger isolation valve
- Partial closure of a shutdown cooling stop valve
- Partial closure of a shutdown cooling suction isolation valve
- Partial closure of a shutdown cooling heat exchanger isolation valve
- Partial closure of a shutdown cooling discharge isolation valve
- Partial closure of a low pressure system discharge isolation valve
- Closure of a low pressure system discharge isolation valve

TABLE 15.0-1 (Cont'd)

C5. Reduction of Shutdown Cooling Effectiveness
- Opening a shutdown cooling flow control valve above requirements
- Leak in a non-essential component cooling water line
- Leak in an essential component cooling water line

C6. Partial Loss of Normal Feedwater and Reactor Coolant Flows
- Loss of a non-safety 6.9kV bus

C7. Loss of Offsite Power
- Loss of grid

D. Reactivity and Power Distribution Anomalies

D1. Uncontrolled Positive Reactivity Insertion
- Sequential CEA withdrawal
- Single part length CEA drop,
- Part length CEA subgroup drop
- Single CEA withdrawal
- CEA subgroup withdrawal
- CEA group withdrawal

D2. Slow Positive Reactivity Insertion
- Closure of boron flow control valve
- Malfunction of makeup controller

D3. Uncontrolled Negative Reactivity Insertion-Single CEA Drop
- Single CEA drop

D4. Uncontrolled Negative Reactivity Insertion-Other
- Sequential CEA insertion
- CEA sub-group drop
- Single part length CEA drop
- Part length CEA subgroup drop
- CEA group drop
- Broken CEA

D5. CEA Ejection
- Rupture of a CEDM nozzle or housing

D6. Slow Negative Reactivity Insertion
- Inadvertent boration

E. Increase in Reactor Coolant System Inventory

E1. Primary System Mass Addition
- Partial closure of the letdown control valve
- Closure of the letdown control valve
- Partial closure of a letdown isolation valve
- Closure of a letdown isolation valve
- Startup of charging pump(s)
- Pressurizer level signal fails low or low-low

F. Decrease in the Reactor Coolant System Inventory

F1. Decrease in primary system mass
- Opening the letdown control valve above requirements
- Loss of a charging pump
- Closure of the volume control tank discharge isolation valve
- Closure of a charging control valve
- Pressurizer level signal fails high
- Regenerative heat exchanger tube rupture

TABLE 15.0-1 (Cont'd)

F2. Small loss of Primary System Fluid-Outside Containment
- Opening a letdown relief valve
- Letdown heat exchanger tube rupture
- Break in 3/8 inch primary sample line
- Break in 3/4 inch reactor coolant pump controlled bleed-off line

F3. Loss of Primary System Fluid-To Secondary System
- Rupture of steam generator tube(s) - exceeding makeup capacity

F4. Large Loss of Primary System Fluid-Outside Containment
- Break in 2 inch letdown line

G. Radioactive Release From a Subsystem or Component

G1. Radioactive liquid waste system failure

G2. Radioactive release due to liquid containing tank failure

G3. Waste gas system failure

G4. Fuel handling accident

H. Primary System Pressure Deviation

H1. Overpressurization of Primary System
- Startup of ah inactive reactor coolant pump
- Inadvertent safety injection actuation signal generation
- Safety injection actuation
- Opening an safety injection tank discharge isolation valve
- Pressurizer pressure signal fails low

H2. Depressurization of Primary System
- Opening a pressurizer spray valve
- Pressurizer pressure signal fails high

TABLE 15.0-2

EVENT TYPE/FREQUENCY MATRIX

		Moderate Frequency Event	Infrequent Event	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
A.	Increased heat Removal By Secondary System		Increased Feed-water Flow Increased Main Steam Flow-Through Turbine	Increased Main Steam Flow-Through Turbine Bypass or Dump Increased Main Steam Flow-Through ADV or MSSV Decreased Feedwater Enthalpy Loss of Main Steam-Small, O.C., Downstream of MSIV	Loss of Main Steam-Small, I.C. Loss of Main Steam-Small, O.C., Upstream of MSIV Loss of Main Steam-Large I.C. Loss of Main Steam-Large, O.C., Upstream of MSIV Loss of Main Steam-Large, O.C., Downstream of MSIV	
B.	Decreased Heat Removal by Secondary System	Isolation of Turbine Partial loss of Normal Feedwater Flow Total Loss of Normal Feedwater Flow – to a SG	Loss of External Load Decreased Main Steam Flow – Down-stream of Header Decreased Main Steam Flow – Up-stream of Header Termination of Main Steam Flow Total Loss of Normal Feedwater Flow – to both SGs Loss of Feedwater Inventory – Small, I.C., Upstream of Check Valve Loss of Feedwater Inventory – Small, O.C., Downstream of Main Feedwater Isolation Valve	Loss of Feedwater Inventory - Small, O.C., Upstream of Main Feedwater Isolation Valve Loss of Feedwater Inventory - Large, O.C., Upstream of Main Feedwater Isolation Valve Partial Loss of Power to Safety Loads Increased Feedwater Enthalpy		Loss of Feedwater Inventor Small, I.C., Downstream of Check Valve Loss of Feedwater Inventor Large, I.C., Downstream of Check Valve Loss of Feedwater Inventor Large, O.C., Downstream of Main Feedwater Isolation Valve. Loss of Feedwater Inventor Large, I.C., Upstream of Check Valve

TABLE 15.0-2 (Cont'd)

		Moderate Frequency Event	Infrequent Event	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
B.	Decreased Heat Removal by Secondary System (Cont'd)		Loss of Normal Power to Half the Plant Loss of Condenser Vacuum Loss of Instrument Air Loss of Condenser Vacuum and Partial Loss of Normal Power to Safety Loads Partial Loss of dc Power			
C.	Decrease Reactor Coolant Flow		One Reactor Coolant Pump Loss of Forced Flow Partial Loss of Shutdown Cooling Flow Partial Loss of Normal Feedwater and Reactor Coolant Flows Loss of Offsite Power	One Reactor Coolant Pump Resistance to Forced Flow Reduction of Forced Flow-Shaft Shear Reduction of Shutdown Cooling		
D.	Reactivity and Power Distribution and Anomalies	Uncontrolled Negative Reactivity Insertion-Single CEA Drop	Uncontrolled Positive Reactivity Insertion Slow Positive Reactivity Insertion Uncontrolled Negative Reactivity Insertion-Other Slow Negative Reactivity Insertion			CEA Ejection

TABLE 15.0-2 (Cont'd)

	Moderate Frequency Event	Infrequent Event	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
E. Increase In RCS Inventory		Primary System Mass Addition			
F. Decrease In RCS Inventory		Loss of Primary System Fluid-To Secondary System	Decrease in Primary System Mass		
			Small Loss of Primary System Fluid-O.C.	Large Loss of Primary System Fluid-O.C.	
G. Radioactive Release From Subsystem or Compartment			Radioactive Liquid Waste System Failure	Waste Gas System Failure	
				Fuel Handling Accident	
			Radioactive Release Due to Liquid Containing Tank Failure		
H. Primary System Pressure Deviations		Overpressuriza-tion of Primary System			
		Depressurization of Primary System			

TABLE 15.0-3

LOW-PROBABILITY INDEPENDENT OCCURRENCES

STEAM DUMP AND BYPASS CONTROL SYSTEM (Subsection 7.7.1.1.5)

1. Failure to Modulate Open When Required

   a. 1 valve fails to open (PCV-8801 or PCV-8802)

   b. 3 valves fail to open (PCV-8803, 8804, 8805)

   c. All valves fail to open

2. Failure to Quick Open When Required

   a. 1 valve fails to quick open (PCV-8801, 8802, 8803, 8804 or 8805)

   b. All valves fail to quick open

3. One Bypass Valve Fails to Quick Close Subsequent to Steam Bypass Operations. Various Steam Bypass Operations are:

   a. 1 valve was initially opened (PCV-8801)

   b. All valves were initially opened

4. Excessive Steam Bypass Flow Due to Proportional/Integral/Differential Controller Failing High (following a valid demand for partial bypass flow)

5. Failure to Generate Automatic Withdrawal Prohibit Signal during Steam Bypass Operation

6. All five Bypass Valves Fail to Both Modulate and Quick Open

7. Failure to Open all Bypass Valves on Manual Demand

REACTIVITY CONTROL SYSTEMS (ADS[a], CEDMCS, RRS) (Subsection 7.7.1.1.1 and 7.7.1.1.6)

1. A Single CEA Stuck While the Remainder of the CEAs are Moving

2. A CEA Subgroup Stuck While the Remainder of the CEA Subgroups are Moving

3. A Regulating Group Fails to Insert or Withdraw While the Remaining Groups are Moving

4. The CEDMCS fails to position CEAs.

[a] ADS = Analog Display System
CEDMCS = Control Element Drive Mechanism Control System
RRS = Reactor Regulating System

TABLE 15.0-3 (Cont'd)

REACTIVITY CONTROL SYSTEM (Cont'd)

5. CEAs Withdraw in Spite of Automatic Withdrawal Prohibit and/or CEA Withdrawal Prohibit

6. Failure to Achieve the Rod Block Function (i.e., Single CEA will withdraw upon erroneous withdrawal demand from RRS or CEDMCS)

7. False Actuation of Rod Block Function (i.e., Single CEA will not withdraw even when required)

FEEDWATER REGULATING SYSTEM (FRS) (Subsection 7.7.1.1.4)

1. Failure of Feedwater Rampback (Turbine Trip Override). Subsequent to a turbine trip, any one or all of the following can result due to a single failure.

    a. 1 Feedwater Control Bypass Valve (FCBV) fails to open to the prescribed position.

    b. 1 Main Feedwater Control Valve (MFCV) fails to close.

2. Failure of High Level Override. Subsequent to a high steam generator level, any one or all of the following can result due to a single failure:

    a. 1 FCBV fails to open to the prescribed position.

    b. MFCV fails to close.

3. Failure of I MFCV to Modulate (open or close) when Required

4. Main Feed Pump Recirculation Valve Fails to Close

TURBINE-GENERATOR CONTROL SYSTEM (TGCS) (Subsection 7.7.1.1.10)

1. Failure to Modulate One or all of the Turbine Control Valves

2. Failure to Trip the Turbine on Parameters Other than Overspeed

REACTOR COOLANT PRESSURE CONTROL SYSTEM (PPCS) (Subsection 7.7.1.1.2)

1. Spray Control Valves Fail to Open on High Pressurizer Pressure

TABLE 15.0-3 (Cont'd)

REACTOR COOLANT PRESSURE CONTROL SYSTEM (Cont'd)

2. Spray Control Valves Stay Opened following Recovery from High Pressure Condition. (The de-pressurizing effects are partially compensated for by the PPCS automatic actuation of the backup heaters.)

3. Failure of Backup Heaters to Turn On, Upon Low Pressurizer Pressure

4. Backup Beaters Fail ON following Recovery from Low Pressure Condition. (The effect can be compensated for by automatically Modulating Open the Spray Control Valves.)

PRESSURIZER LEVEL CONTROL SYSTEM (Subsection 7.7.1.1.3)

1. One or Both Backup Charging Pumps Fail to Turn ON

2. One or Both Backup Charging Pumps Fail to Turn OFF

3. Letdown Flow Control Valve Fails to Close to the Minimum Position in Response to a Low Level Condition. (Only 1 letdown flow path is normally used. The backup flow path is blocked, and would require operator action to be opened.)

4. Letdown Flow Control Valve Fails to Open in Response to a High Level Condition

5. Letdown Flow Control Valve Closes to the Zero Flow Position in Response to a Low Level Error Signal

CONDENSATE AND FEEDWATER SYSTEM (Subsection 10.4.7)

1. One Back-Flow Check Valve Fails to Close

2. One Main Feed Isolation Valve Fails to Close on MSIS

3. Condensate Recirculation Valves Fail to Close

MAIN STEAM SUPPLY SYSTEM (Section 10.3)

1. One Main Steam Isolation Valve Fails to Close on Actuation of a Main Steam Isolation Signal

2. One Main Steam Safety Valve Fails to Reseat

3. One Atmospheric Dump Valve Fails to Reclose

AUXILIARY FEEDWATER SYSTEM (Subsection 10.4.9)

1. Failure of any One Auxiliary Feed Pump to Deliver

TABLE 15.0-3 (Cont'd)

PRESSURIZER SAFETY AND RELIEF VALVES (Subsection 5.4.1-3)

1. One Pressurizer Safety Valve Fails to Reseat

2. One Power-Operated Pressurizer Relief Valve Fails to Open when Required

3. One Power-Operated Pressurizer Relief Valve fails to Re-close

CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS) (Subsection 9.3.4)

1. An Isolation Valve in the Letdown Line (Inside or Outside Containment) Fails to Re-open Subsequent to Containment isolation Signal or Safety Injection Actuation Signal (SIAS). Consequently, letdown flow cannot be re-established.

2. One of the 2 Charging Line Valves (downstream of the Regenerative Heat Exchanger Fail to Close as Required to Establish Auxiliary Spray Flow for Plant Cooldown.

EMERGENCY CORE COOLING SYSTEM (Section 6.3)

1. Failure of One High Pressure Safety Injection (HPSI) or Low Pressure Safety Injection (LPSI) Pump following SIAS

2. Simultaneous Loss of One HPSI, LPSI, and Containment Spray Pump following SIAS (only if offsite power is unavailable)

3. Simultaneous Loss of One HPSI Pump and One CS Pump following a Recirculation Actuation Signal

4. One hot leg Injection Line Valve Fails to Open when Required

SHUTDOWN COOLING SYSTEM

1. Loss of half of Maximum Shutdown Cooling Capacity due to Failure of a Valve which Blocks Flow through One Shutdown Cooling Heat Exchanger

ELECTRIC POWER SYSTEM (Section 8)

No System Failure Modes are Postulated

REACTOR PROTECTIVE SYSTEM (Section 7.2)

No Significant Failure Modes are Postulated

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM (Section 7.3)

No Significant Failure Modes are Postulated

TABLE 15.0-4

CATEGORIZATION VS ACCEPTANCE GUIDELINE SCHEME

Frequency Group	Moderate Frequency Events	Infrequent Events	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Event Probability	May Occur During a Calendar Year	May Occur During a Plant Life-time	Low Probability of occurring During a Plant Lifetime	Very Low Probabi-lity of occurring During a Plant Lifetime	Exceedingly Low Probability of Occurring During a Plant Lifetime
Acceptance Guidelines:					
On Offsite Dose	Very Small Fraction of 10CFR100	Very Small Fraction of 10CFR100	Small Fraction of 10CFR100	Well Within 10CFR100	Up to 10CFR100
On Reactor Coolant System Pressure	Upset Stress Limits	Emergency Stress Limits	Faulted Stress Limits	Faulted Stress Limits	Faulted Stress Limits
On Fuel Performance*	Peak Pin DNBR $\geq$ 1.19 and No Fuel Melting	Peak Pin DNBR $\geq$ 1.19 and No Fuel Melting	Maintain Coolable Geometry	Maintain Coolable Geometry	Maintain Coolable Geometry
On Loss of Shutdown Margin	Shutdown Margin Greater Than Zero (In Operating Modes 2 Through 6)	Shutdown margin Greater Than Zero (In Operating Modes 2 Through 6)	Shutdown Margin Greater Than Zero (In Operating Modes 2 Through 6)	Shutdown Margin Greater Than Zero (In Operating Modes 2 Through 6)	Shutdown Margin Greater Than Zero (In Operating Modes 2 Through 6)

(*) DNBR limit for Cycle 1 was 1.20. Cycle 2 DNBR limit was 1.28. Current cycle also has a DNBR limit of 1.28.

TABLE 15.0-4 (Cont'd)

Question No.

440.8 Table 15.0-4 provides the staff no quantitative basis upon which to evaluate your plant. Modify this table to include the numerical values which are applicable to St. Lucie Unit 2. Justify your quantification.

Response

The criterion in Table 15.0-4 are consistent with the quantitative detail provided in the Standard Review Plan; therefore, the NRC Staff may review the Chapter 15 analyses to these or to the applicable Standard Review Plan criteria.

To demonstrate that these results are consistent with the Standard Review Plan criteria, and to assist in evaluating these results, Table 15.0-4a summarizes the results of all analyses presented in Chapter 15.

TABLE 15.0-4a

SUMMARY OF CHAPTER 15 RESULTS

Section *	Event	Peak RCS Pressure psia	Offsite Dose, rem: 2 Hour, Exclusion Area, Thyroid	Offsite Dose, rem: 2 Hour, Exclusion Area, Whole Body	Offsite Dose, rem: Entire Event, Low Population Zone, Thyroid	Offsite Dose, rem: Entire Event, Low Population Zone, Whole Body	% Fuel Failure	Other
15.1.2.1	Incr. FW Flow + FFT	<2,350	$1.2x10^{-1}$	$9.2x10^{-6}$	$1.3x10^{-1}$	$7.5x10^{-6}$	None	--
15.1.4.3	MSLB (LIC) + FFT	2,150	only incrementally more adverse than 15.1.2.1				3.7	--
15.1.5.1	MSLB (LOC) + LOP + TL	--	91	.42	67	.31	4.0	--
15.1.5.3	MSLB (LIC) + LOP	2,150	only incrementally more adverse than 15.1.2.1				7.6	--
15.2.1.1	Isol. of Turbine -20%	2,250	$2.3x10^{-1}$	$1.2x10^{-5}$	$1.9x10^{-1}$	$8.8x10^{-6}$	None	Meets SAFDL
15.2.1.2	Isol. of Turbine -102%	2,671	Less than 15.2.1.1----------				None	--
15.2.2.1	Isol. of Turbine + LPI	2,257	1.0	$1.1x10^{-5}$	$5.6x10^{-1}$	$6.6x10^{-6}$	None	--
15.2.2.2	Loss of Cond. Vac. + FFT	2,692	Less than 15.2.2.1----------				None	--
15.2.3.2	Loss of Cond. Vac. + LOP	2,738	Not Significant (for a limiting fault)				None	--
15.2.3.2.1	FWLB.	2,715	--	--	--	--	None	--
15.2.5.2	FWLB + LOP	2,807	Not Significant----------				None	--
15.3.2.1	Loss of Offsite Power	2,573	$1.8x10^{-1}$	$6.2x10^{-6}$	$1.7x10^{-1}$	$5.9x10^{-6}$	None	--
15.3.2.2	Loss of Offsite Power	2,694	Less than 15.3.2.1----------				None	--
15.3.3.3	RCP Shaft Seizure + FFT	≤2,694	Only incrementally more adverse than 15.3.2.1				5.0	--
15.3.4.3	RCP Shaft Seizure + LOP	≤2,694	Only incrementally more adverse than 15.3.2.1				13.0	--
15.3.5.1	RCP Shaft Seizure + LOP +TL	2,427	29.4	.42	25.6	.364	13.0	--
15.4.1.3	Single CEA drop	2,150	No event-related offsite doses----------				None	Meets SAFDL
15.4.2.3	Part length rod subgroup drop	2,272	Not significant----------				None	--
15.4.2.4	Boron Dilution	--	--	--	--	--	--	>15 or >30 minutes to loss of shutdown margin

* Section numbers are historical and may not coincide with current section numbers

TABLE 15.0-4a (Cont'd)

Section *	Event	Peak RCS Pressure psia	Offsite Dose, rem: 2 Hour Exclusion Area Thyroid	2 Hour Exclusion Area Whole Body	Entire Event Low Population Zone Thyroid	Entire Event Low Population Zone Whole Body	% Fuel Failure	Other
15.4.3.1	Part length CEA group drop + FFT + TL	2,295	3.0	4.0×10^{-2}	3.0	4.1×10^{-2}	1.8	--
15.4.3.3	Part length CEA group drop + FFT	--	--	--	--	--	1.8	--
15.4.4.2	Seq. CEA withdrawal + LOP	2,633	Only incrementally more adverse than 15.4.3.1				--	--
15.4.4.3	Part length CEA group drop + LOP	2,329	--	--	--	--	7.0	--
15.4.5	CEA ejection + FFT	2,260	2.2	1.8×10^{-1}	3.3	4.2×10^{-1}	9.5	--
15.6.2.1	Steam Gen. Tube Rupture	--	2.6×10^{-1}	8.4×10^{-4}	2.3×10^{-1}	4.7×10^{-4}	None	--
15.6.3.1	Open letdown relief valve + TL	--	6.0×10^{-1}	1.4×10^{-1}	4.3×10^{-1}	8.7×10^{-2}	None	--
15.6.4.1	Open letdown relief valve + PIS	--	5.1	1.4×10^{-1}	2.9	8.7×10^{-2}	None	--
15.6.3.1	Open letdown relief valve + PIS	--	6.0×10^{-1}	1.4×10^{-1}	2.9	8.7×10^{-2}	None	--
15.6.5.1	Letdown line break + PIS + TL	--	27	8.8×10^{-3}	27	4.8×10^{-3}	None	--
15.7.3.1	WMS Failure	--	1.3×10^{-1}	6.4×10^{-1}	7.3×10^{-2}	3.5×10^{-1}	--	--
15.7.4.1.1	Waste gas tank failure	--	4.3×10^{-4}	9.6×10^{-3}	7.1×10^{-4}	5.3×10^{-3}	--	--
15.7.4.1.2	Fuel handling accident	--	1.3	6.4×10^{-2}	7.4×10^{-1}	3.5×10^{-2}	--	--
15.7.4.1.3	Deleted							

* Section numbers are historical and may not coincide with current section numbers

TABLE 15.0-5

CHAPTER 15 SECTION DESIGNATION

Each Section is identified as 15.W with trailing zeros omitted where:

W = 1 Increase in heat removal by the secondary system
2 Decrease in heat removal by the secondary system
3 Decrease in Reactor Coolant System flowrate
4 Reactivity and power distribution anomalies
5 Increase in reactor coolant inventory
6 Decrease in reactor coolant inventory
7 Radioactive release from a subsystem or component
8 Primary system pressure deviation

TABLE 15.05a

MATRIX OF WRITEUPS PRESENTED IN
THE ST LUCIE UNIT 2 FSAR

Section 15.1 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Null	Major Increased Feedwater Flow With a Failure to Achieve a Fast Transfer to a Startup Transformer	Minor	Minor	Minor
Reactor Coolant System Pressure	Null	No Approach	No Approach	No Approach	No Approach
Fuel Performance	Null	Minor	Minor	Major Loss of Main Steam, Large, Inside Containment With a Failure to Achieve a Fast Transfer to a Startup Transformer	Major Loss of Main Steam, Large, Inside Containment, With a Loss of Offsite Power as a Result of Turbine Trip and a High Steam Generator Tube Leakage Rate
Loss of Shutdown Margin	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

Section 15.2 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Major Isolation of Turbine	Major Isolation of Turbine With the Low Probability Inde-pendent Occurrence of a Stuck Open Main Steam Safety Valve	Minor	Minor	Minor
Reactor Coolant System Pressure	Major Isolation of Turbine	Major Loss of Condenser Vacuum with a Failure to Achieve a Fast Transfer to a Startup Transformer	Major Loss of Condenser Vacuum with the Loss of Offsite Power as a Result of Turbine Trip	Pointing ←	Major Loss of Feedwater In-ventory-Large, Inside Containment, Downstream of Check Valve, with the Loss of Offsite Power as a Result of Turbine Trip
Fuel Performance	Minor	Minor	Minor	Minor	Minor
Loss of Shutdown Margin	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

Section 15.3 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Null	Major Loss of Offsite Power	Minor	Minor	Minor
Reactor Coolant System Pressure	Null	Major Loss of Offsite Power	Pointing	Pointing	Pointing
Fuel Performance	Null	Minor	Minor	Minor	Pointing
Loss of Shutdown	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

Section 15.4 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	No Approach	Minor	Major Uncontrolled Positive Reactivity Insertion (part Length CEA Group Drop) with a Failure to Achieve a Fast Transfer to a Startup Transformer and a High Steam Generator Tube Leakage Rate	Minor	Major CEA Ejection with a Failure to Achieve a Fast Transfer to a Startup Transformer and a High Steam Generator Tube Leakage Rate
Reactor Coolant System Pressure	No Approach	Pointing	Pointing	Major Uncontrolled Positive Reactivity Insertion (Sequential CEA Withdrawal) with Loss of Offsite Power as a Result of Turbine Trip	Pointing
Fuel Performance	Major Uncontrolled Negative Reactivity Insertion Single CEA Drop	Major Positive Reactivity Insertion (part Length CEA Group Drop)	Major Uncontrolled Positive Reactivity Insertion (part Length CEA Group Drop) with a Failure to Achieve a Fast Transfer to a Startup Transformer	Major Uncontrolled Positive Reactivity Insertion (PLCEA Group Drop) with Loss of Offsite Power as a Result of Turbine Trip	CEA Ejection with a Failure to Achieve a Fast Transformer and High Steam Generator Tube Leakage Rate
Loss of Shutdown Margin	No Approach	Major Slow Positive Reactivity Insertion	Pointing	Pointing	Pointing

TABLE 15.05a (Cont'd)

Section 15.5 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Null	No Approach	No Approach	No Approach	No Approach
Reactor Coolant System	Null	Pointing →	Minor	← Pointing	Pointing
Fuel Performance	Null	No Approach	No Approach	No Approach	No Approach
Loss of Shutdown Margin	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

Section 15.6 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Null	Major	Major	Major	Major
		Loss of Primary System Fluid - to Secondary System	Small Loss of Primary System Fluid Outside Containment with a High Steam Generator Tube Leakage Rate	Small Loss of Primary System Fluid Outside Containment with a High Pre-existing Iodine Concentration	Small Loss of Primary System Fluid Outside Containment with a high Pre-existing Iodine Concentration and a High Event Generated Iodine Spike
Reactor Coolant System Pressure	Null	No Approach	No Approach	No Approach	No Approach
Fuel Performance	Null	Minor	Minor	Minor	Minor
Loss of Shutdown Margin	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

Section 15.7	Frequency Category				
Acceptance Guideline	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Null	Null	Major Radioactive Liquid Waste System Lead or Failure	Major 1. Waste Gas Tank Failure 2. Fuel Handling Accident	Null
RCS Pressure	Null	Null	No Approach	No Approach	Null
Fuel Performance	Null	Null	No Approach	No Approach	Null
Loss of Shutdown Margin	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

Section 15.8 Acceptance Guideline	Frequency Category				
	Moderate	Infrequent	Limiting Fault-1	Limiting Fault-2	Limiting Fault-3
Offsite Dose	Null	Minor	Minor	Minor	Minor
Reactor Coolant System Pressure	Null	Major	Major	Pointing	Pointing
		Overpressurization of Primary System	Overpressurization of Primary System and a Low Probability Independent Occurrence of a PORV failing to Open	←	
Fuel Performance	Null	Minor	Minor	Minor	Minor
Loss of Shutdown Margin	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

TABLE 15.0-5a (Cont'd)

EXPLANATIONS OF WRITEUP TYPES

Null	This type of writeup is used to describe a matrix element that has no events assigned to it. For example, there is no event that results in an increased heat removal (from the primary system) by the secondary system and has an estimated frequency of occurrence which would classify it as a Moderate Frequency event.
No Approach	This type of writeup is used to describe a matrix element that contains events which do not produce any approach to an acceptance guideline. For example, an event that results in an increased heat removal (from the primary system) by the secondary system is characterized by a decreasing primary system pressure. Therefore, this event results in no approach to the acceptance guideline on reactor coolant pressure boundary pressure.
Pointing	This type of writeup is used to describe a matrix element that contains events which do not produce consequences any worse than those produced by an event described in another section (matrix element). A less frequent element may point left to a bounding event meeting stricter guidelines. Also a more frequent element may point right to a bounding less frequent event, only if this event meets the acceptance guidelines of the initial more frequent event category. For example, none of the Limiting Fault-1 events resulting in a decrease in reactor coolant flowrate produce reactor coolant pressure boundary pressures greater than that produced by the Limiting Infrequent Event. (No additional failures affect the pressure increase.)
Minor	This type of writeup is used to describe a matrix element that contains events which do not produce a significant approach to an acceptance guideline. A significant approach is quantitatively defined for each acceptance guideline.
Major	This type of writeup is used to describe a matrix element that contains events which produce a significant approach to an acceptance guideline.

TABLE 15.0-6

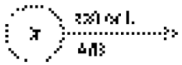
SEQUENCES OF EVENTS-SYMBOLS, ACRONYMS, AND DEFINITIONS

	Identifies Event Group to be evaluated.
	Identifies Safety Function which is required to mitigate the effects of the transient.
	Identifies Safety Function which is performed but which is not required for successful event termination.
	Identifies a system or component (which is automatically actuated).
	Identifies a system having two independent "trains" of equipment or channels.
P	Indicates that a safety action of the system is passive. (No active failures are associated with the system).
M	Indicates that operator action is used to actuate the system
X Y	Sensed variable "Y" initiates an action, only if "X" is not at its setpoint.
S.F.	When placed beneath a main path - alternate path combination, indicates that the combinaton is single active failure proof.
	Identifies the sensed variable input, if directed towards a system, and an action if directed away from a system symbol.
	Vertical solid path indicates the success path which connects the actions assumed in the analysis in order to attain each of the safety functions.
	A dotted vertical line indicates an alternative or redundant path to attain a safety function.
	The highlighting (dotted overlay) on path indicates a success path utilizing only safety grade equipment.
X Y Z	Sensed variables X, Y, Z are used for automatic action, manual action or post event monitoring. Used primarily for control systems.

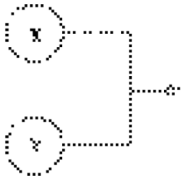
TABLE 15.0-6 (Cont'd)

Indicates connection with another drawing. Allows transfer between sheets of one drawing.

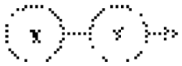
Branched path indicating a different success path for a given set of plant or event conditions. The diamond represents a decision/ selection process.



Sensed variable “X” is used for automatic action, manual action or post-event monitoring, CR or L indicate the location (CR=control room, L=local) of the signal or indication, for manual actions only. A/B indicates the degree of redundancy of the instrumentation, i.e., A out of B channels are required to be at the setpoint.



Any one of the multiple sensed variables initiates action. The solid line indicated the first or most likely (or assumed) method of initiating the action.



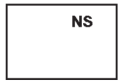
All of the sensed variables are required to initiate the system action.

X/Y

Indicates the minimum redundancy of a system or success path:

X = number of components or trains required to generate an action.

Y = total number of components or trains available.



Identifies a non-safety grade system.

Sensed Variable "X" is used to generate an alarm.

A/B indicates the redundancy of the instrumentation:
A = Number of signals required to actuate a safety action
B = Total number of signals generated

C/D indicates the redundancy of the alarm

TABLE 15.0-6 (Cont'd)

SENSED VARIABLES OR ENVIRONMENTAL CONDITIONS

Symbol	Meaning
C	Concentration
F	Flow
G	CEA Positions
L	Level
Φ	Neutron Flux
p	Pressure
Δp	Differential Pressure
Z	Valve or Damper Position Indication
Q	Power
RE	Radiation
S	Speed
T	Temperature
ΔT	Temperature Difference
TD	Time Delay
V	Voltage

VALUE AT ACTUATION SYMBOLS

Symbol	Meaning
C	Closed
H	High
HH	High-High
L	Low
LL	Low-Low
N	Normal
0	Open

SYSTEM OR SENSED POINT SYMBOLS

Symbol	Meaning
a	Area
ab	Auxiliary Building
ave	Average
b	Boron
cbo	Controlled Bleedoff
cl	Cold Leg (Reactor Coolant System)
cr	Control Room
f	Feedwater
fb	Fuel Handling Building
h	Hydrogen
hl	Hot Leg (Reactor Coolant System)
ld	Letdown
pvs	Plant Vent Stack
r	Reactor
s	Steam
saf	Safety Bus
sgb	Steam Generator Blowdown Line
sgA	Steam Generator A
sgB	Steam Generator B
sh	Steam Header
t	Turbine
tb	Turbine Building
4.16	4.16 KV Bus
6.9	6.9 KV Bus

All other sensed variable subscripts are identical to those in the table or component and system abbreviations.

For clarification, a few sensed variables are presented below to illustrate the abbreviation system.

System	Meaning
RE_{sgb} H	High Steam Generator Blowdown Line Radiation
P_{cb} HH	High-High Containment Pressure
L_{SG} L	Low Steam Generator Level

SPECIAL SYMBOLS

Some sensed variables cannot be identified by the symbols listed above. For these instances, a special symbol is used to describe the variables. These special symbols are listed below.

Symbol	Meaning
DNBR	Departure from Nucleate Boiling Ratio
HHSGLS	High-High Steam Generator Level
HSGLS	High Steam Generator Level
LLPLS	Low-Low Pressurizer Level Signal
ΔP_{sg}	Differential Pressure (across a single SG)
$\Delta P_{x\text{-}y}$	Differential Pressure (between SGX & SGY, $\Delta P_{sgA\text{-}B} = P_{sgA} - P_{sgB}$
QD	Local Power Density
QL	Logarithmic Power Level
QS	Startup Power Level
RIA	Rod Insertion Alarm
RII	Rod Insertion Inhibit

These special symbols may be further described by the third letter described above

Symbol	Meaning
QL_rH	High Reactor Logarithmic Power Level

TABLE 15.0-6 (Cont'd)

SUCCESS PATH SAFETY FUNCTION	SAFETY FUNCTION DESCRIPTION
1. REACTIVITY CONTROL	
Reactivity Control (Trip)	Rapid insertion of negative reactivity into the core to produce subcriticality immediately following an initiating event.
Reactivity Control (Boron)	Establishment of sufficient boron concentration in the core to maintain subcriticality following the initiating event using systems actuated by the SIAS.
Reactivity Control (Shutdown)	Establishment of cold shutdown boron concentration prior to or during cooldown of the plant.
Reactivity Control (Long Term Recirculation)	Switching of Safety Injection System from injection to recirculation mode.
2. REACTOR HEAT REMOVAL	
Natural Convective Heat Removal	Maintenance of core cooling by natural circulation in the primary loop, including natural convection in the core sufficient to prevent violation of the fuel design limits.
Non-4 Pump Heat Removal	Maintenance of core cooling by means of forced flow (other than normal four pump flow) sufficient to prevent violation of the fuel design limits. Specifically not considered as part of this safety function are those actions performed to accomplish the emergency core cooling safety functions.
ECC Injection Phase	Provision of coolant to the RCS sufficient to maintain a coolable reactor geometry after an SIAS and before low refueling water tank level signal.
ECC Recirculation (Short Term)	Provision of adequate coolant to the RCS following low refueling water tank level signal and automatic switchover to the containment sump. Core coolant is recirculated back into the primary system after it leaks out.
ECC Recirculation (Long Term)	Establishment of conditions to bring plant to shutdown cooling entry conditions or cold shutdown, following initiation of ECC recirculation. Reestablishment of cooling water to RCPs, if still operating. Alignment: of SIS for hot leg injection, in addition to cold leg injection, to unaffected RCS piping.
Reactor Heat Removal (Shutdown)	Provision of coolant to the RCS to achieve cold shutdown conditions, using the Shutdown Cooling System.

TABLE 15.0-6 (Cont'd)

SUCCESS PATH SAFETY FUNCTION	SAFETY FUNCTION DESCRIPTION
3. SECONDARY SYSTEM INTEGRITY	
Secondary System Pressure/ Level/Heat Sink Control	Maintenance of secondary system pressure and steam generator water level within allowable limits such that the secondary system does not overpressurize, overfill, or empty and can be used to remove decay or reactor heat from primary system immediately following an unplanned event.
Secondary System Pressure/ Level/Heat Sink Control (Long Term)	Maintenance of secondary system pressure and steam generator water level within limits such that a heat sink is provided for the primary system to facilitate cooldown of the plant to shutdown cooling entry conditions.
4. PRIMARY SYSTEM INTEGRITY	
Primary System Pressure/ Level/Control	Maintenance of primary system pressure and level within limits such that the primary system pressure does not exceed the acceptance guidelines given In Table 15.0-4.
Primary System Pressure/ Level Control (Long Term)	Control of primary system pressure and level, and required associated actions, during cooldown from hot standby to cold shutdown entry conditions to prevent exceeding pressure-temperature guidelines during the cooldown process, and to allow the Shutdown Cooling System to be used.
5. CONTAINMENT INTEGRITY	
Containment Pressure/ Temperature Control	Maintenance of containment pressure and temperature within limits such that the containment integrity is maintained.
Containment Pressure/ Temperature Control (Recirculation)	Maintenance of containment pressure and temperature within limits following exhaustion of the RWT by switching the Containment Spray System to the recirc-culation mode following generation of a low refueling water tank level signal.
6. COMBUSTIBLE GAS CONTROL	
Combustible Gas Control	Identification of, and conditioning of post-event containment atmosphere or treatment of event generated flammables, to prevent formation of flammable or explosive mixtures.

TABLE 15.0-6 (Cont'd)

SUCCESS PATH SAFETY FUNCTION	SAFETY FUNCTION DESCRIPTION
7. PLANT HABITABILITY	
Control Room Habitability	Conditioning of the control room atmosphere during an event to ensure habitability and control of personnel radiation exposure. (see Section 9.4)
Fuel Handling Building Habitability	Conditioning of the fuel handling building atmosphere during an event to ensure habitability and control of personnel radiation exposure.
Auxiliary Building Habitability	Conditioning of the auxiliary building atmosphere during an event to ensure habitability and control of personnel radiation exposure.
8. RADIOACTIVE EFFLUENT CONTROL	
Containment Isolation	Isolation of containment building to prevent escape of radioactivity to the environs in excess of that allowed by the acceptance guidelines of Table 15.0-4.
Primary System Isolation	Isolation of primary system to prevent coolant loss or escape or radioactivity to the environs in excess of that allowed by the acceptance guidelines of Table 15.0-4.
Secondary System Isolation	Isolation of all or part of the secondary system to prevent coolant loss or escape of radioactivity to the environs in excess of that allowed by the acceptance guidelines of Table 15.0-4.
Radioactive Material Treatment	Chemical treatment of radioactive materials to reduce the quantity that escapes or is discharged to the environs. (see section 6.5.2).
Radioactive Material Treatment (Long Term)	Chemical and/or mechanical treatment or radioactive materials to reduce the quantity that escapes or is discharged to the environs. (see Subsections 6.5.1 and 6.5.2).

TABLE 15.0-6 (Cont'd)

SUCCESS PATH SAFETY FUNCTION	SAFETY FUNCTION DESCRIPTION
9. RESTORATION OF A.C POWER	
Restoration of Safety Power	Starting and loading of onsite, standy ac power supply.
Restoration of Non-Safety Power	Transfer of non-safety ac loads from the unit auxiliary transformer to the start-up transformer, when offsite power is available.
Restoration of Non-Safety A.C. Power	Manual loading of non-safety buses on to startup transformer.
10. SPENT FUEL POOL HEAT REMOVAL	
Spent Fuel Pool Heat Removal	Cooling of the spent fuel pool following a loss of non-safety ac power (see Section 9.1).

TABLE 15.0-6 (Cont'd)

COMPONENT AND SIGNAL ABBREVIATIONS

SYMBOL	DESCRIPTION
ABVS	Auxiliary Building Main Ventilation System
ADV	Atmospheric Dump Valves
AFW	Auxiliary Feedwater System
AS	Auxiliary Spray
BAMP	Boric Acid Makeup Pump
BAMS	Boric Acid Makeup System
BAMT	Boric Acid Makeup Tank
BCS	Boron Control System
BCSS	Boron Control System Signal
BUVR	Bus Undervoltage Relays
CB	Containment Building
CCS	Containment Cooling System
CCW	Component Cooling Water System
CD	Condenser
CEA	Control Element Assemblies
CEDM	Control Element Drive Mechanism
CEDM-MG	Control Element Drive Mechanism Motor-Generator Set
CEDMCS	Control Element Drive Mechanism Control System
CES	Condenser Evacuation System
CGS	Combustible Gas Control System
CHA	Containment Hydrogen Analyzer
CHRS	Containment Hydrogen Recombiner System
CI	Containment Isolation (pseudo) System
CIS	Containment Isolation Signal (CIAS)
CMDS	CEA Motion Demand Signal
CRACS	Control Room Air Conditioning System
CRECS	Control Room Emergency Cleanup System
CSS	Containment Spray System
CSAS	Containment Spray Actuation Signal
CST	Condensate Storage Tank
CTS	Condensate Transfer System
CVCS	Chemical and Volume Control System
CW	Circulating Water System
CWP	Control Rod Withdrawal Prohibit Signal

TABLE 15.0-6 (Cont'd)

SYMBOL	DESCRIPTION
DEH	Digital Electro-Hydraulic Control System
DG	Diesel Generator System
EDT	Equipment Drain Tank
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
FBVS	Fuel Handling Building Ventilation System
FTB	Fast (Dead Bus) Transfer Breaker
FRS or FWRS	Feedwater Regulating System
GLS	Generator Lockout Signal
HPS	Hydrogen Purge System (continuous)
HPSI	High Pressure Safety Injection
HT	Holdup Tank
HVAC	Heating, Ventilation and Air Conditioning
IA	Instrument Air System
IRS	Iodine Removal System
LCV	Letdown Control Valve
LPSI	Low Pressure Safety Injection
LS	Load Sequencer
MFIV	Main Feed Isolation Valve
MFW	Main Feedwater System
MSBV	Main Steam Bypass Valve
MS	Main Steam System
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve
MSSV	Main Steam Safety Valves
MU	Makeup Water System

TABLE 15.0-6 (Cont'd)

SYMBOL	DESCRIPTION
PCPS	Fuel Pool Cooling and Purification
PH	Pressurizer Heaters
PLCS	Pressurizer Level Control System
PORV	Power Operated Relief Valves
PPCS	Pressurizer Pressure Control System
PSV	Pressurizer Safety Valves
PWP	Primary Water Pump
PWST	Primary Water Storage Tank
PZR	Pressurizer
QT	Quench Tank
RAS	Recirculation Actuation Signal
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RPS	Reactor Protective System
RRS	Reactor Regulating System
RTSS	Reactor Trip Circuit Breaker Switchgear
RTS	Reactor Trip Signal
RWT	Refueling Water Tank
SBCS	Steam Bypass Control System
SBVS	Shield Building Ventilation System
SCS	Shutdown Cooling System
SCST	Spray Chemical Storage Tank
SFP	Spent Fuel Pool
SG	Steam Generator
SGBS	Steam Generator Blowdown System
SIAS	Safety Injection Actuation Signal
SIS	Safety Injection System
SIT	Safety Injection Tank
SS	Sampling System
SUT	Startup Transformer

TABLE 15.0-6 (Cont'd)

SYMBOL	DESCRIPTION
TGCS	Turbine Generator Control System
TTS	Turbine Trip Signal
UAT	Unit Auxiliary Transformer
UVS	Undervoltage Signal
VCT	Volume Control Tank
WML	Waste Management Liquid

TABLE 15.0-7

REACTOR PROTECTIVE SYSTEM ANALYSIS SETPOINTS USED IN

THE SAFETY EVALUATION
Cycle 1

Event	Parameter	Analysis Value[1]		Analysis Response Time Constant, T[2] sec.	Delay Time,[3] sec.
All considered other than those listed below	Low Flow, % of initial total core flow	93		0.25	0.4
	High Pressurizer Pressure, psia	2420	[2428]	0.75	0.4
	Low SG Pressure, psia	590	[557]	0.75	0.4
	Low SG Water Level, % of tap span	Note 8		0.75	0.4
	Thermal Margin/Low Pressure - (Low Pressure Floor), psia	Variable (1875)		Note 7 0.75	0.4 0.4
	High Local Power Density	Note 7			0.4
	High Power Level, △Q%, USL%, LSL%(4)	17,130,17		Note 6	0.4
	High Containment Pressure, psig	6		0.75 [1.15]	0.4
	High SG△ Pressure, psig	222		0.75	0.4
	Low EHC Oil Pressure, psig*	Note 7			
CEA Ejection	High Pressurizer Pressure, psia	2455	[2465]	0.75	0.4
	High Power Level [5],△Q%, USL%, LSL%[4]	17,130,17		Note 6	0.4
Loss of Feedwater	Low S.G. Pressure, psia	510	[491]	0.75	0.4
Inventory Inside Containment and Loss of Main Steam	Low S.G. Level, % of tap span	Note 8		0.75	0.4
Incident Inside Containment	Low flow, % of initial total core flow	70			0.4

* Not used to mitigate accident

TABLE 15.0-7 (Cont'd)

Notes:

1. The analysis setpoint value is the actual value of a measured parameter at which the protection action sequence is assumed to begin.

   A change in environmental qualification accuracies resulted in a revision of the analytical setpoints to the values given in brackets. The events in Table 15.0-7a were each assessed and found to be insignificantly impacted except for Subsection 15.1.5.1 which required a minor revision.

2. The assumed response time represents the elapsed time between the occurrence of a trip condition at the sensor input and the generation of a signal at the sensor output. The response times are determined using the indicated time constants (T) and an appropriate transfer function.

3. The delay time is the time between the following events: (1) the sensor output reaches analysis setpoint value and (2) the opening of the reactor trip switchgear.

4. Q is defined as the fixed increment between the analysis setpoint value and the measured power level

   USL is defined as the upper analysis setpoint limit

   LSL is defined as the lower analysis setpoint limit

   For description of the variable High Power level setpoint and the variable Thermal Margin/Low Pressure setpoint see Section 7.2.

5. High power level is qualified for the first 10 seconds of CEA Ejection only.

6. The analysis response time constants used for the high power level trip are as follows: Excore Detectors - 0.1 sec., and ΔT Power Calculator - 10.0 sec.

7. Not used to mitigate transients in the safety evaluation.

8. Required to be actuated prior to actual level dropping below the lower narrow range level tap.

TABLE 15.0-7a

EVENTS CONSIDERED IN ASSESSMENT OF ENVIRONMENTAL QUALIFICATION EQUIPMENT UNCERTAINTIES (See Note 1 of Table 15.0-7)

Section	Event
15.1.4.3	Large Main Steam Line Break, Inside Containment with Failure to Fast Transfer a 6.9 kV Bus
15.1.5.1	Large Main Steam Line Break, Outside Containment, Loss of Offsite Power and Tech Spec Tube Leakage
15.1.5.3	Large Main Steam Line Break, Inside Containment with Loss of Offsite Power
15.2.1.2	Isolation of Turbine at 102% Power
15.2.2.1	Isolation of Turbine at 20% Power with an MSSV Stuck Open
15.2.2.2	Loss of Condenser Vacuum with Failure to Fast Transfer a 6.9 kV Bus
15.2.3.2	Loss of Condenser Vacuum with a Loss of Offsite Power
15.2.5.2	Large Feedwater Line Break, Inside Containment with a Loss of Offsite Power
15.4.4.2	Sequential CEA Withdrawal with a Loss of Offsite Power
15.A.1	Large Main Steam Line Break, Inside Containment with Loss of Offsite Power, HPSI Pump Failure, Stuck CEA
15.A.1	Large Main Steam Line Break, Inside Containment, MSIV Failure and a Stuck CEA
15.A.1	Large Main Steam Line Break at Hot Zero Power, Inside Containment, with Loss of Offsite Power, HPSI Pump Failure, and Stuck CEA,
15.A.1	Large Main Steam Line Break at Hot Zero Power, Inside Containment, MSIV Failure, and Stuck CEA

TABLE 15.0-8
EMERGENCY SAFETY FEATURES ACTUATION SYSTEM
ANALYIS SETPOINTS USED IN THE SAFETY EVALUATION
Cycle 1

Engineered Safety Features Actuation Signal	Analysis Setpoint Value[1]
A. For all events other than those listed below:	
Safety Injection Actuation Signal (SIAS)	
Low Pressurizer Pressure (psia)	1580
High Containment Pressure (psig)	6
Recirculation Actuation Signal (RAS)	
Low Refueling Water Tank Level (ft)	5.67
Containment Spray Actuation Signal (CSAS)	
High-High Containment Pressure (psig) (Coincident with Safety Injection Signal)	11
Containment Isolation Actuation Signal (CIAS)	
High Containment Pressure (psig)	5
High Containment Radiation (r/hr)	10
Main Steam Isolation Signal (MSIS)	
Low Steam Generator Pressure (psig)	450[2]
High Containment Pressure, psig	6
B. For Isolation of Turbine at 20% Power with a stuck open main steam safety valve	
Main Steam Isolation Signal (MSIS)	
Low Steam Generator Pressure (psig)	750[2]

Notes:

(1) The analysis setpoint value is the actual value of a measured parameter at which the protection action sequence is assumed to begin.

(2) 750 psig represents the upper error bound on low SG pressure, 450 psig represents the lower error bound on low SG pressure.

TABLE 15.0-9

INITIAL CONDITION RANGE CONSIDERED IN THE SAFETY EVALUATION
Cycle 1

Parameter	Units	Range
Core Power, B	% of 2560 MWt, + 18 Mwt RCP input	$0 \leq B \leq 102$
Radial 1-pin peaking factor, Fr	--	$Fr \leq 1.7$
Axial Shape Index, ASI	--	± 0.3
Core Inlet Coolant Flow Rate, G	% of 370,000 gpm	$100 \leq G \leq 109.7$
Core Coolant Inlet [a)] Temperature, T		
at 100% power	F	$540 \leq T \leq 551$
at 0% power	F	$525 \leq T \leq 540$
RCS Pressure, P	psia	$2150 \leq P \leq 2350$
Pressurizer Level, L_p		
at 80-100% power	% level [d)]	$40 \leq L_P \leq 65$
at 0-80% power	% level[d)]	$30 \leq L_P \leq 65$
Feedwater Temperature, T_F[b)]	F	$80 \leq T_f \leq 455$
Steam Generator Level, L_{SG}	% of narrow range tap span	$35 \leq L_{SG} \leq 90$
Secondary System Pressure	psia	See note c)

a) Initial coolant temperatures used depended on the initial core power.

b) Feedwater temperatures used depended on the initial core power.

c) Secondary system pressure is consistent with primary side conditions (temperature, flow, and power) and is based on steam generator heat transfer characteristics at full power design conditions (see Section 5.4).

d) This level is the empty to fill level of an assumed cylindrical pressurizer, i.e., 65 percent level corresponds to 65 percent of the pressurizer volume being filled.

TABLE 15.0-9a

SHUTDOWN CEA REACTIVITY WORTHS USED FOR ANALYSES (%△p)
(CYCLE 1)

Event	CEA Worth Used	
	Hot Full Power	Hot Zero Power
All except CEA ejection and steam line break (SLB)	5.50	2.50
CEA ejection	5.05	1.53
SLB assuming stuck CEA	6.68*	5.00
SLB assuming no stuck CEA	7.78	5.00

* An additional 0.96%△p) was subtracted from this value (yielding 5.72%△p) to maximize potential for return-to power. This amount was included in the moderator cooldown reactivity function for other analyses.

TABLE 15.0-10

DECONTAMINATION FACTORS USED
IN OFFSITE DOSE CALCULATIONS [4]

Release Path	Decontamination Factors[1] Iodines	Other Isotopes
Primary leak outside containment[2]	1	1
Releases through atmospheric dump valves or main steam safety valves	10[3]	1
Releases through condenser for cooldown	100	1

(1) Decontamination factor equal to 10 means 1/10 of the total activity in the mass released is released to the air.

(2) Certain events show appreciable releases from containment (e.g., CEA ejection, Subsection 15.4.5.1). Treatment of these releases is discussed in the appropriate individual sections.

(3) In the event of steam generator dryout due to blowdown to the environment, the entire steam generator radionuclide inventory is assumed to be released to the environment.

(4) The information presented in this table is of historical significance and will be retained.

TABLE 15.0-11

EFFECT OF SINGLE FAILURE OF MSIV OR ONE HPSI PUMP OR ONE HPSI PUMP PLUS ONE LPSI PUMP ON MAXIMUM POST-TRIP REACTIVITY, CORE AVERAGE POWER, AND CORE AVERAGE HEAT FLUX FOR 6.36ft^2 MAIN STEAM LINE BREAKS. AUTOMATIC ACTUATION OF AUXILIARY FEEDWATER IS ASSUMED. Cycle 1

INITIAL POWER LEVEL	OFF-SITE POWER	SINGLE FAILURE	MAXIMUM POST-TRIP:		
			REACTIVITY ($10^{-2}\Delta\rho$)	CORE AVERAGE POWER (% OF 2570 MW)	CORE AVERAGE HEAT FLUX (% OF FULL POWER VALUE)
FULL	LOSS OF	ONE HPSI AND ONE LPSI PUMP	+0.003	8.3	8.5
		MSIV	-0.05	6.8	7.1
	AVAIL-ABLE	ONE HPSI PUMP	-0.3	10.4	11.1
		MSIV	-0.3	10.2	11.2
ZERO	LOSS OF	ONE HPSI AND ONE LPSI PUMP	+0.3	0.8	1.0
		MSIV	+0.1	1.6×10^{-3}	0.4
	AVAIL-ABLE	ONE HPSI PUMP	-0.5	1.1×10^{-4}	1.4
		MSIV	-0.5	1.1×10^{-4}	1.5

TABLE 15.0-12

ST. LUCIE UNIT 2, DESIGN BASIS
EVENTS CONSIDERED IN THE CYCLE 2 SAFETY ANALYSIS

Increase in Heat Removal by the Secondary System

15.1.3.3.1	Decrease in Feedwater Temperature
15.1.2.1.6	Increase in Feedwater Flow
15.1.3.3.2	Increased Main Steam Flow
15.1.3.7.1	Inadvertent Opening of a Steam Generator Safety Valve or Atmospheric Dump Valve
15.1.4.3.5.1*	Steam System Piping Failures Inside Containment Pre-Trip
15.1.5.1.5	Outside Containment Pre-Trip Power Excursions
15.1.4.3.5.2	Post-Trip Analysis

Decrease in Heat Removal by the Secondary System

15.2.2.1.6	Loss of External Load
15.2.1.1.6	Turbine Trip
15.2.2.2.6	Loss of Condenser Vacuum
15.10.5	Loss of Normal AC Power
15.2.2.1.7	Loss of Normal Feedwater
15.2.5.1.1*	Feedwater System Pipe Breaks

Decrease in Reactor Coolant Flowrate

15.3.2.2.5	Partial Loss of Forced Reactor Coolant Flow
15.3.2.2.6	Total Loss of Forced Reactor Coolant Flow
15.3.5.1.7*	Single Reactor Coolant Pump Shaft Seizure/Sheared Shaft

Reactivity and Power Distribution Anomalies

15.4.2.3.7	Uncontrolled CEA Withdrawal from a Subcritical or Low Power Condition
15.4.2.2.1	Uncontrolled CEA Withdrawal at Power
15.4.2.3.8	CEA Drop
15.4.2.3.9	CVCS Malfunction (Inadvertent Boron Dilution)
15.4.5.1*	Control Element Assembly Ejection

Increase in Reactor Coolant System Inventory

15.5.3.2.2	CVCS Malfunction
15.5.3.2.3	Inadvertent Operation of the ECCS During Power Operation

Decrease in Reactor Coolant System Inventory

15.6.3.1.6	Pressurizer Pressure Decrease Events
15.6.3.1.7	Small Primary Line Break Outside Containment
15.6.2.1.7*	Steam Generator Tube Rupture

Miscellaneous

15.2.2.2.7	Asymmetric Steam Generator Events

*Postulated accidents

TABLE 15.0-13

DBEs ANALYZED WITH RESPECT TO OFFSITE DOSE CRITERION

Event	Section
A) Anticipated Operational Occurrences	
1) Inadvertent opening of a Steam Generator Atmospheric Dump Valve or Safety Valve	15.1.3.7.1
2) Loss of Normal AC Power	15.10.5
B) Postulated Accidents	
1) Steam system Piping Failures; Steam Line Break Event Outside Containment Pre-Trip Power Excursions	15.1.4.3.5.1
2) Feedwater System Pipe Breaks	15.2.5.1.1
3) Single Reactor Coolant Pump Shaft Seizure	15.3.5.1.7
4) Small Primary Line Break Outside Containment	15.6.3.1.7
5) Steam Generator Tube Rupture	15.6.2.1.7

TABLE 15.0-14

DBEs ANALYZED WITH RESPECT TO RCS PRESSURE CRITERION

Event	Section
A) Anticipated Operational Occurrences	
1) Loss of Condenser Vacuum	15.2.2.6
2) Loss of Normal AC Power	15.10.5
3) Uncontrolled CEA Withdrawal at Power	15.4.2.2.1
B) Postulated Accidents	
1) Feedwater System Pipe Breaks	15.2.5.1.1

TABLE 15.0-15

DBEs ANALYZED WITH RESPECT TO FUEL PERFORMANCE

Event	Section
A) Anticipated Operational Occurrences Requiring RPS Trip to Assure that the SAFDLs are not Exceeded	
1) Decrease in Feedwater Temperature	15.1.3.3.1
2) Increase in Feedwater Flow	15.1.2.1.6
3) Increased Main Steam Flow	15.1.3.3.2
4) Uncontrolled CEA Withdrawal from a Subcritical or Low Power Condition	15.4.2.3.7
5) Uncontrolled CEA Withdrawal at Power	15.4.2.2.1
6) Pressurizer Pressure Decrease Events	15.6.3.1.6
B. Anticipated Operation Occurrences for which RPS Trips and/or Sufficient Steady State Margin (LCO) are Necessary to Prevent Exceeding the SAFDLs	
1) Total Loss of Forced Reactor Coolant Flow	15.3.2.2.6
2) CEA Drop	15.4.2.3.8
3) Asymmetric Steam Generator Events	15.2.2.2.7
C. Postulated Accidents	
Steam System Piping Failures;	
1) Inside Containment Pre-Trip Power Excursions	15.1.3.5.1
2) Outside Containment Pre-Trip Power Excursions	15.1.5.1.5
3) Post Trip Analysis	15.1.4.3.5.2
4) Single Reactor Coolant Pump Shaft Seizure	15.3.5.1.7
5) Control Element Assembly Ejection	15.4.5.1.6

TABLE 15.0-16

DBEs ANALYZED WITH RESPECT TO SHUTDOWN MARGIN CRITERION

Event	Section
A) Anticipated Operational Occurrences	
1)* Inadvertent Opening of a Steam Generator Safety Valve or Atmospheric Dump Valve	15.1.3.7.1
2) CVCS Malfunction (Inadvertent Boron Dilution)	15.4.2.3.9
B) Postulated Accidents	
1)* Steam System Piping Failure, Post Trip Analysis	15.1.4.3.5.2

* These events were considered to ensure reliable control of reactivity following trip.

TABLE 15.0-17

ST. LUCIE 2 UNIT 2, CYCLE 2
CORE PARAMETERS INPUT TO SAFETY ANALYSES

Safety Parameters	Units	Reference Cycle Values (Cycle 1)	Cycle 2 Values
Total RCS Power (Core Thermal Power + Pump Heat)	MWt	2630	2720*, 2774
Maximum Steady State Temperature	°F	551	549*, 552
Minimum Steady State RCS Pressure	psia	2200	2225*, 2172
Rated Reactor Coolant Flow	gpm	370,000	377,500*, 363,000
Negative Axial Shape LCO Extreme Assumed at Full Power (Ex-Cores)	I_p	-.3	-.25
Maximum CEA Insertion at Full Power	% Insertion of Lead Bank	28	25
Maximum Initial Linear Heat Rate for Transient	KW/ft	13.0	13.0
Steady State Linear Heat Rate for Fuel CTM Assumed in the Safety Analysis	KW/ft	21.0	22.0
CEA Drop Time from Removal of Power to Holding Coils to 90% Insertion	sec	3.0	2.7
Minimum DNBR			
CE-1		1.20	1.28**
McBeth		1.30	1.30

* For events under category B of Table 15.0-15 the effects of uncertainties on these parameters were accounted for statistically (see Appendix I). Therefore these values do not include uncertainties.

** Cycle 2 value for MDNBR based on the CE-1 condition is the result of the statistical combination of uncertainty program which cause the MDNBR values to increase (see Appendix 1).

TABLE 15.0-17 (Cont'd)

Safety Parameters	Units	Reference Cycle Values (Cycle 1)	Cycle 2 Values
Radial Peaking Factors			
For DNB Margin Analyses (F_r^T)			
Unrodded Region		1.60	1.70
Bank 5 Inserted to PDIL Limit at 100% Power		1.7	1.74
For Planar Radial Component ($F_{xy}T$) of 3-D Peak (CTM Limit Analyses)			
Unrodded Region		1.60	1.75
Lead Bank Inserted to PDIL Limit at 100% Power		1.75	1.91
Maximum Augmentation Factor		1.055	1.055
Moderator Temperature Coefficient	$10^{-4}\Delta\rho/°F$	-2.7 to +.5	-2.7 to +.5 (below 70% power) -2.7 to 0.0 (70% power and above)
Shutdown Margin (Value Assumed in Limiting EOC Zero Power SLB)	$\%\Delta\rho$	-5.0	-5.0

TABLE 15.0-18

RPS AND ESFAS TRIP SETPOINTS AND DELAY TIMES
ASSUMED IN SAFETY ANALYSIS

RPS Trip Function	Technical Specification Value	Analysis Setpoint	Total Delay Time, (sec)
Variable Power Level - High (% Above Initial Power Level)	9.61	10	0.4(1)
Variable Power Level - Ceiling (% Rated Thermal Power)	107	109(2), 105(3)	0.4(1)
Variable Power Level - Floor (% Rated Thermal Power)	15	17(4)	
Pressurizer Pressure - High Psia	2370	2428, 2465(5)	1.15
Pressurizer Pressure - Low (Floor of Thermal Margin/ Low Pressure), Psia	1900	1820(6)1785(5)	0.9(1)
Steam Generator Pressure - Low Psia	626	557,540(5),510(7)	1.15
Steam Generator Pressure - High Difference, Psia	120	222	1.15
Steam Generator Level - Low % Narrow Range Tap Span	20.5	5.0	1.15
Reactor Coolant Flow - Low % of Rated Flow	95.4	70.0(5), 93.0	0.65
Containment Pressure - High Psig	3.0	4.65	1.15

TABLE 15.0-18 (Cont'd)

ESFAS Trip Function	Technical Specification Value	Analysis Setpoint	Total Delay Time, (sec)
Safety Injection Actuation Signal (SIAS) on Pressurizer Pressure - Low, Psia	1736	1648, 1578(5)	30.0
Main Steam Line Isolation Signal (MSIS) on Steam Generator Pressure - Low Psia	600	460(5)	6.75
Main Feedwater Isolation on Steam Generator Pressure - Low, Psia	600	460(5)	5.15

(1) When credit is taken for ΔT Power Calculator portion of the trip, Resistance Temperature Detector (RTD) response time of 14.00 seconds is explicitly modelled.

(2) Credit for the ceiling of variable high power trip was taken only for the Steam Line Break Event (pre-trip power peaks). Other events which took credit for variable high power trip conservatively used a setpoint of 112% of rated power (10% above initial power of 102%).

(3) 2% uncertainty was taken in negative direction in Steam Line Break Event (post-trip power peaks) since it will result in more adverse cooldown (see Subsection 15.1.4.3.5.2).

(4) Additional uncertainties were added to this value for conservatism for the CEA Ejection Event initiated from hot Zero Power.

(5) Values include harsh environment uncertainties (for Inside Containment Steam Line Break and Feedline Break Events).

(6) Pressurize Pressure Decreasing Events (Subsection 15.6.3.1.6) used an analysis setpoint of 1799 psi which is conservative with respect to this value.

(7) A conservatively low analysis setpoint used in Hot Zero Power post trip steam line break event (Subsection 15.1.4.3.5.2).

TABLE 15.0-19

PARAMETERS USED IN CALCULATING SITE BOUNDARY DOSE *

Parameter	Units	Value
Primary to Secondary Leak Rate	gpm	1.0
Reactor Coolant System Maximum Allowable Concentration (DEQ I-131)	μCi/gm	1.0
Reactor Coolant System Maximum Concentration for Pre-existing Iodine Condition (PIS)	μCi/gm	60.
Accident Generated Iodine Spiking Factor		500
Reactor Coolant System Maximum Allowable Concentration of Noble Gases	Ci/gm	$100/\bar{E}$
Steam Generator Maximum Allowable Concentration (DEQ I-131)	μCi/gm	0.1
Partition Factor:		
Atmospheric Dump Value		1.0
Condenser Air Ejectors		.01
Main Steam Safety Valves		1.0
Water Steam Phase Partition		.01
Atmospheric Dispersion Coefficient	sec/m^3	
Exclusion Area Boundary (EAB)		1.64×10^{-4}
Low Population Zone		7.1×10^{-5}
Breathing Rate	m^3/sec	3.47×10^{-4}
Dose Conversion Factor	Rem/Ci	1.48×10^{6}

* This is Historical Information and may not represent current values.

TABLE 15.0-20

LOSS OF NON-CLASS IE BUS
AND
AFFECT ON INSTRUMENTATION

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
1	120V ac PP-220 125V dc BUS 2AB	NS/NA	RRS	PT-1100X (CWD-97)	NS/NA	Pressurizer Pressure	PZR HTR'S and Spray Control (PZR Pressure Control)	Same as Safety Channel A Ref. Leg (PT-1102A)
2	120V ac PP-221 125V dc BUS 2AB	NS/NB	RRS	PT-1100Y (CWD-98)	NS/NB	Pressurizer Pressure		Same as Safety Channel B Ref. Leg (PT-1102B)
3	120V ac PP-220	NS/NA	RRS	TE-1111X (CWD 138)	NS/NA	Reactor Coolant Loop Temperature	Recorder (Ind. only)	Loop 2A Hot Leg (RCS)
4	120V ac PP-221	NS/NB	RRS	TE-1121X (CWD-137)	NS/NB	Reactor Coolant Loop Temperature	Recorder (Ind. only)	Loop 2B Hot Leg (RCS)
5	120V ac PP-220	NS/NA	RRS	TE-1111Y (CWD-138)	NS/NA	Reactor Coolant Loop Temperature	CEDS-AWP	Loop 2A2 Cold Leg (RCS)
6	120V ac PP-221	NS/NB	RRS	TE-1121Y (CWD-137)	NS/NB	Reactor Coolant Loop Temperature	CEDS-AWP	Loop 2B2 Cold Leg (RCS)
7	120V ac PP-220	NS/NA	RRS	PT-22-37AB	NS/NA	First Stage Turbine Pressure		
7A	120V ac PP-234	NS/NAB	RRS	PT-22-37B	NS/NAB	First Stage Turbine Pressure		
8	120V ac PP-220 125V dc PP-201	NS/NA IE/SA	PZR Level Control	LT-1110X (CWD-90)	NS/NA	Pressurizer Level	PZR Press. Control (HTR Interlocks)	Same as Safety Channel A (PT-1102A)

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
9	120V ac PP-221 120V ac PP-202	NS/NB IE/SB	PZR Level Control	LT-1110Y (CWD-90)	NS/NB	Pressurizer Level	PZR Pressure Control (HTR Interlocks)	Same as Safety Channel B (PT-1102B)
10	120V ac PP-220 PP-221	NS/NA NS/NB	RRS	RRS Level Setpoint 01RRS/405	NS/NA	Pressurizer Level Control (RRS 1 or 2 may be selected as inputs to X & Y via 01-RRS/405)		
11	125V dc BUS 2A	NS/NA	Reactor Coolant Pump	PS-1157 (CWD-101)	NS/NA	Reactor Coolant Pump Start Permissive		RCP-2A1
12	125V dc BUS 2B	NS/NB	Reactor Coolant Pump	PS-1167 (CWD-109)	NS/NB	Reactor Coolant Pump Start Permissive		RCP-2A2
13	125V dc BUS 2B	NS/NB	Reactor Coolant Pump	PS-1177 (CWD-105)	NS/NB	Reactor Pump Start Permissive		RCP-2B1
14	125V dc BUS 2A	NS/NA	Reactor Coolant Pump	PS-1187 (CWD-113)	NS/NA	Reactor Coolant Pump Start Permissive		RCP-2B2
15	120V ac PP-214	NS/NA	Reactor Coolant Pump	SS-1152 (CWD-101)	NS/NA	Oil Lift Pumps Start/Stop Control (Speed Switch)		RCP-2A1
16	120V ac PP-210	NS/NB	Reactor Coolant Pump	SS-1162 (CWD-109)	NS/NB	Oil Lift Pumps Start/Stop Control (Speed Switch)		RCP-2A2

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
17	120V ac PP-210	NS/NB	Reactor Coolant Pump	SS-1172 (CWD-105)	NS/NB	Oil Lift Pump Start/Stop Control (Speed Switch)		RCP-2B1
18	120V ac PP-214	NS/NA	Reactor Coolant Pump	SS-1182 (CWD-113)	NS/NA	Oil Lift Pump Start/Stop Control (Speed Switch)		RCP-2B2
19	120V ac PP-208	NS/NA	Boron Control System (CVCS)	PT-2201 (CWD-151)	NS/NA	Req'd for cold Shutdown		Letdown Line
20	125V dc BUS 2A	IE/SA	Boron Control System (CVCS)	PDS-2216 (CWD-157)	IE/SA	Flow Control		REGEN HX P
21	480V ac NCC 2A2	NS/NA	Boron Control System (CVCS)	TIC-2206 (CWD-168)	NS/NA	BA make-up HTR Controls for 2A & 2B, via HS		BA Make-up Tank 2A
22	480V ac MCC 2B2	NS/NB	Boron Control System (CVCS)	TIC-2207 (CWD-169)	NS/NB	BA make-up HTR Controls for 2A & 2B, via HS		BA Make-up Tank 2A
23	480V ac MCC 2A2	NS/NA	Boron Control System (CVCS)	TIC-2208 (CWD-170)	NS/NA	BA make-up HTR Controls for 2B, via HS		BA Make-up Tank 2B
24	480V ac MCC 2B2	NS/NB	Boron Control System (CVCS)	TIC-2209 (CWD-171)	NS/NB	BA make-up HTR Controls for 2B, via HS		BA Make-up Tank 2B

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
25	480V ac MCC 2B6	NS/NB	Boron Control System (CVCS)	TE-2213 (CWD-172)	NS/NB	BAMT HTR Control		8A Batching Tank
26	120V ac PP-220	NS/NA	Boron Control System (CVCS)	TE-2221 (CWD-150)	NS/NA	Req'd for cold Shutdown		REGEN HX outlet (letdown)
27	120V ac PP-221	NS/NB	Boron Control System (CVCS)	TE-2223 (CWD-151)	NS/NB	Req'd for cold Shutdown	(CCW Valve)	Letdown HX outlet piping
28	120V ac PP-220	NS/NA	Boron Control System (CVCS)	TE-2224 (CWD-152)	NS/NA	High Temp Diversion for IX, RT		Letdown HX outlet piping
29	120V ac PP-221	NS/NB	Boron Control System (CVCS)	LT-2226 (CWD-154)	NS/NB	Req'd for cold shdn (Makeup Controls) WMS/VCT Flow Diversion		VCT
30	120V ac PP-221	NS/NB	Boron Control System (CVCS)	LT-2227 (CWD-154)	NS/NB	Req'd for cold shdn (Makeup Controls) WMS/VCT Flow Diversion		VCT
31	125V dc BUS 2A	IE/SA	Boron Control System (CVCS)	LS2234X (CWD-187)		Charging Pump Stuffing Box Water level Control		Charging Pump 2A

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
32	125V dc BUS 2B	IE/SA	Boron Control System (CVCS)	LS-2234Y (CWD-187)		(Charging Pump) Stuffing Box Water Level Control		Charging Pump 2B
33	125V dc BUS 2AB	IE/SAB	Boron Control System (CVCS)	LS-2234Z (CWD-187)		(Charging Pump) Stuffing Box Water Level Control		Charging Pump 2C
34	120V ac PP-220	NS/NR	Boron Control System (CVCS)	Ft-2210X (CWD-192)		Make-up Flow to VCT		Reactor Make-up Line
35	120V ac PP-221	NS/NB	Boron Control System (CVCS)	Ft-2210Y (CWD-192)		BA Make-up Flow to VCT		Boric Acid Make-up
36	120V ac Vital PNL 2B	NS/NB	Stm. Bypass (RRS-2)	HIC-8801 (CWD-748)		Turbine bypass to Cond Valve		
37	120V ac Vital PNL 2B	NS/NB	Stm. Bypass Control (RRS-2)	HIC-8802 (CWD-749)	NS/NB	Stm Dump to Cond Valve		
38	120V ac Vital PNL 2B	NS/NB	Stm. Bypass Control (RRS-2)	HIC-8803 (CWD-749)	NS/NB	Stm Dump to Cond Valve		

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
39	120V ac Vital PNL 2B	NS/NB	Stm Bypass Control (RRS-2)	HIC-8804 (CWD-750)	NS/NB	Stm Dump to Cond Valve		
40	120V ac Vital PNL 2B	NS/NB	Stm Bypass Control (RRS-2)	PIC-8010 (CWD-750)	NS/NB	Stm Dump to Cond Valve		
41	120V ac Vital PNL 2A	NS/NA	Stm Bypass Control (RRS-2)	FWCS Stm Flow	NS	FT-8011, FT-8021 inputs via FW Cont Sys Cab's 2A & 2B, respectively		
41-A	120V ac Vital PNL 2B	NS/NB	Stm Bypass Control (RRS-2)	FWCS Stm Flow	NS	FT-8011, FT-8021 inputs via FW Cont Sys Cab's 2A & 2B, respectively		
42	120V ac Vital PNL 2B	NS/NB	Stm Bypass Control (RRS-2)	PT-8010 (CWD-748)	NS/NB	Steam Header Pressure		
43	120V ac Vital PNL 2B	NS/NB	Stm Bypass Control (RRS-2)	PT-8020 (CWD-748)	NS/NB	Steam Header Pressure		
44	120V ac Vital PNL 2B	NS/NB	Stm Bypass Control (RRS-2)	Frequency/ Load change desired	NS/NB	DEH-Turb Contol		

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
45	120V ac PP-220 PP-221	NS/NA NS/NB	RRS	T_{AVG} Input		T_{AVG} Signal generated by RRS 1 or 2, switch selectable	RRS	RRS 1 or 2
46	CEDM Holding Power	NS/		Contact Closure RTSG UV	NS/	Trip Turbine Generator Annuciator		
47	120V ac Vital PNL 2A	NS/NA	Feed-water Control System	LT-9005 (CWD-619)	NS/NA	SIG Level instru-ments Powered From Respective FWCS CAB'S 2A & 2B		
48	120V ac Vital PNL 2B	NS/NB	Feed-water Control System	LT-9006 (CWD-624)	NS/NB	SIG Level instru-ments Powered From Respective FWCS CAB'S 2A & 2B		
49	120V ac Vital PNL 2A	NS/NA	Feed-water Control System	LT-9011 (CWD-619)	NS/NA	SIG Level instru-ments Powered From Respective FWCS CAB'S 2A & 2B		
50	120V ac Vital PNL 2B	NS/NB	Feed-water Control System	LT-9021 (CWD-624)	NS/NB	SIG Level instru-ments Powered From Respective FWCS CAB'S 2A & 2B		

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
51	120V ac Vital PNL 2A	NS/NA	Feed-water Control System	FT-8011 (CWD-619)	NS/NA	Main Stm Flow from each FWCS CH to SBCS (RRS #2)		
52	120V ac Vital PNL 2B	NS/NB	Feed-water Control System	FT-8021 (CWD-624)	NS/NB	Main Stm Flow from each FWCS CH to SBCS (RRS #2)		
53	120V ac Vital PNL 2A	NS/NA	Feed-water Control System	FT-9011 (CWD-619)	NS/NA	Main Feedwater Flow		
54	120V ac Vital PNL 2B	NS/NB	Feed-water Control System	FT-9021 (CWD-624)	NS/NB	Main Feedwater Flow		
55	120V ac Instr BUS 2A	IE/MA	Feed-water Control System	LIC-9013/ 9023A (CWD-376, 377)	IE/MA	FW Override on High Signal Level	N/A	Safety Channel A
56	120V ac Instr BUS 2B	IE/MB	Feed-water Control System	LIC-9013/ 9023B (CWD-376, 377)	IE/MB	FW Override on High Signal Level	N/A	Safety Channel B
57	120V ac Instr BUS 2C	IE/MC	Feed-water Control System	LIC-9013/ 9023C (CWD-376, 377)	IE/MC	FW Override on High Signal Level	N/A	Safety Channel C

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
58	120V ac Instr BUS 2D	IE/MD	Feed-water Control System	LIC-9013/ 9023D (CWD-376, 377)	IE/MD	FW override on High Signal Level	N/A	Safety Channel D
59	125V dc BUS 2AB	NS/NA	Turb Control	20/AST	NS/NB	Turb Trip Solenoid		
60	125V dc BUS 2AB	NS/NB	Turb Control	20/	NS/	Turb Trip Solenoid		
*61	120V ac Vital PNL 2A	NS/NA	Turb Control	RXI/DEB	NS/NA	Turbine Runback		
62	125V ac Vital PNL 2B	NS/NB	Turb Control	DEH	NS/NB	Turb. Control DEH		
63	125V dc BUS 2B	NS/NB	Gen Contr	ANN-AA1	NS/NB	Gen H_2 Annunciator		
64	120V ac Vital PNL 2B	NS/NB	Gen Contr	Excit. Swgr	NS/NB	Gen Excitation Contr		
65	125V dc BUS 2B	NS/NB	Gen Contr	Excit. Swgr	NS/NB	Gen Volt Regulator		
66	120V ac Vital PNL 2A	NS/NA	FW	FI-09-1A	NS/NA	FW Flow Pump 2A Indic		
67	120V ac Vital PNL 2B	NS/NB	FW	FI-09-1B	NS/NB	FW Flow Pump 2B Indic		

* The Turbine Runback feature has been deleted, therefore, this item no longer applies.

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
68	120V ac Vital PNL 2A	NS/NA	Con-densate		NS/NA	Cond Pump 2A Recirc Control		
69	120V ac Vital PNL 2B	NS/NB	Con-densate		NS/NB	Cond Pump 2B Recirc Control		
70	120V ac Vital PNL 2A	NS/NA	Con-densate		NS/NA	Cond Pump 2A Recirc Control		
71	120V ac Vital PNL 2A	NS/NA	Con-densate	0_2R-05-1	NS/NA	Dissolved 0_2 Analyzer Rec		
72	120V ac Vital PNL 2B	NS/NB	Con-densate	CR-05-1	NS/NB	Conductivity Recorder		
73	120V ac Vital PNL 2A	NS/NA	Con-densate	PHR-05-1	NS/NA	PH Recorder		
74	120V ac Vital PNL 2A	NS/NA	FW	--	NS/NA	FW Pump 2A Recirc Contr		
75	120V ac Vital PNL 2B	NS/NB	FW	--	NS/NA	FW Pump 2B Recirc Contr		
76	120V ac Vital PNL 2A	NS/NA	FW	Various	NS/NA	FW Pump 2A Bearing FW Pump 2B Bearing Temp Indic		
77	120V ac Vital PNL 2B	NS/NB	FW	Various	NS/NB	FW Pump 2B Bearing Temp Indic		
78	PP-238 125V dc	NS	FW/Cond AFW, Htr Drain	Various	NS	Temporary Strainer Alarms		Temporary strainers were used for initial system cleanup and are no longer used.

TABLE 15.0-20 (Cont'd)

Item	Instr. Bus	Bus Class/CH	Serves System	Instr. Tag/ Loop	Instr. Class/ Channel	Description	Other Systems Fed by Device	Common Sense Line/HDR Remarks
79	125V dc BUS 2AB	NS/NB	Gen Prot	8B UF (CWD-882)	NS/NB	Generator under-freq/Lockout Rel		
80	125V dc BUS 2AB	NS/NA	Gen Prot	8G GP (CWD-883)	NS/NA	Generator Primary Lockout Relay		
81	125V dc BUS 2AB	NS/NB	Gen Prot	8G GP (CWD-885)	NS/NB	Generator Backup Lockout Relay		
82	125V dc BUS 2A	NS/NA	Aux Power	4Kv Swgr-2A2, 2A1, 480V Swgr 2A1	NS/NA	Feeder Protection & Control		
83	125V dc BUS 2B	NS/NB	Aux Power	4Kv Swgr-2B2, 2B1, 480V Swgr 2B1	NS/NA	Feeder Protection & Control		
84	125V dc PP-719 or 120V ac PP-221	NS/ NS/NB	Anun-ciators	ALC-1,-2.-3	NS	Station Alarms		

Note: 1) For impact on plant safety and instrument busses required for cold shutdown refer to Subsection 15.0.2.1.1, response 420.01 (Action Item 1b).

TABLE 15.0-21

ALARM INDICATION FOR LOSS OF POWER
TO SAFETY AND NON-SAFETY POWER BUS

Item	Bus or Distr. Panel	Class	Dedicated Alarm	Bus Failure Detection	Redundant Bus
1	120/208V PP-201	IE/SA	No	Failure of Ind & Controls	PP-202
2	120/208V PP-202	IE/SB	No	" " " " "	PP-201
3	120/208V PP-203	IE/SAB	No	" " " " "	PP-201 & PP-202
4	120/208V PP-204	NS/NA	No	" " " " "	PP-207
5	120/208V PP-205A	NS/NA	No	" " " " "	PP-205B
6	120/208V PP-205B	NS/NB	No	" " " " "	PP-205A
7	120/208V PP-207	NS/NB	No	" " " " "	PP-204
8	120/208V PP-208	NS/NA	No	" " " " "	PP-209
9	120/208V PP-209	NS/NB	No	" " " " "	PP-208
10	120/208V PP-210	NS/NB	No	" " " " "	PP-214
11	120/208V PP-211	IE/SA	No	" " " " "	PP-212
12	120/208V PP-212	IE/SB	No	" " " " "	PP-211
13	120/208V PP-213	NS/NB	No	" " " " "	None
14	120/208V PP-214	NS/NA	No	" " " " "	PP-210
15	120/208V PP-215	NS/NA	No	" " " " "	PP-216
16	120/208V PP-216	NS/NB	No	" " " " "	PP-215
17	120/208V PP-217A	NS/-	No	" " " " "	None
18	120/208V PP-220	NS/NA	No	" " " " "	PP-201
19	120/208V PP-221	NS/NB	No	" " " " "	PP-220
20	120/208V PP-222	NS/NA	No	" " " " "	None
21	120/208V PP-234	NS/NAB	No	" " " " "	None
22	120/208V PP-235	NS/NA	No	" " " " "	PP-236
23	120/208V PP-236	NS/NB	No	" " " " "	PP-235

TABLE 15.0-21 (Cont'd)

ALARM INDICATION FOR LOSS OF POWER
TO SAFETY AND NON-SAFETY POWER BUS

Item	Bus or Distr. Panel	Class	Dedicated Alarm	Bus Failure Detection	Redundant Bus
24	120/208V PP-241	NS/NA	No	" " " " "	PP-242
25	120/208V PP-242	NS/NB	No	" " " " "	PP-241
26	120/208V PP-250	IE/SA	No	" " " " "	PP-251
27	120/208V PP-251	IE/SB	No	" " " " "	PP-250
28A	125V dc Bus 2A	IE/SA	Yes	Ann & Fail of Ind	125V DC Bus 2B
28B	125V dc Bus 2A	NS/NA	No	Failure of Ind.	125V DC Bus 2B
29A	125V dc Bus 2B	IE/SB	Yes	Ann & Fail of Ind.	125V DC Bus 2A
29B	125V dc Bus 2B	NS/NB	No	Failure of Ind.	125V DC Bus 2A
30A	125V dc Bus 2AB	IE/SAB	Yes	Ann & Failure of Ind.	125V DC Bus 2A/2B
30B	125V dc Bus 2AB	NS/NAB	No	Failure of Ind.	125V DC Bus 2A/2B
31	125V dc Bus 2C	NS/NB	Yes	Ann & Failure of Ind.	None
32	125V dc P-218	NS/NA	No	Fail of Ind. & Controls	PP-219
33	125V dc P-219	NS/NB	No	Fail of Ind. & Controls	PP-218
34	125V dc P-238	IE/SA	No	Fail of Ind. & Controls	PP-239
35	125V dc P-239	IE/SB	No	Fail of Ind. & Controls	PP-238
36	125V dc P-240	IE/SAB	No	Fail of Ind. & Controls	PP-232/PP339
37	125V dc Bus MA	IE/MA-1	No	Fail of Ind. & Controls	
38	125V dc Bus MB	IE/MB-1	No	Fail of Ind. & Controls	Redundant
39	125V dc Bus MC	IE/MC-1	No	Fail of Ind. & Controls	To Each
40	125V dc Bus MD	IE/MD-1	No	Fail of Ind. & Controls	Other
41	120V ac Vital PP 2A	NS/NA	No	Fail of Ind. & Controls	Vital PP-2B
42	120V ac Vital PP 2B	NS/NB	No	Fail of Ind. & Controls	Vital PP-2A

TABLE 15.0-21 (Cont'd)

ALARM INDICATION FOR LOSS OF POWER
TO SAFETY AND NON-SAFETY POWER BUS

Item	Bus or Distr. Panel	Class	Dedicated Alarm	Bus Failure Detection	Redundant Bus
43	120V ac Instr. Bus 2 MA	IE/MA	Yes	Ann & Fail of Ind	Redundant
44	120V ac Instr. Bus 2 MB	IE/MB	Yes	Ann & Fail of Ind	to
45	120V ac Instr. Bus 2 MC	IE/MC	Yes	Ann & Fail of Ind	each
46	120V ac Instr. Bus 2 MD	IE/MD	Yes	Ann & Fail of Ind	other
47	120V/208V/P-206	IE/SA	No	Periodic Space Htr Inspection	None
48	120V/108V/P-223	IE/SB	No	Periodic Space Htr Inspection	None
49	120V/208V/P-232	IE/SB	No	Periodic Space Htr Inspection	None
50	120V/208V/P-233	IE/SAB	No	Periodic Space Htr Inspection	None
51	120V/208V/P-243	IE/SA	No	Periodic Space Htr Inspection	None
52	120V/208V/P-244	NS/NB	No	Periodic Space Htr Inspection	None
53	120V/208V/P-245	NS/NA	No	Periodic Space Htr Inspection	None
54	120V/208V/P-246	IE/SA	Mo	Periodic Space Htr Inspection	None
55	120V/208V/P-247	IE/SB	No	Periodic Space Htr Inspection	None
56	120V/208V/P-248	NS/-	No	Periodic Space Htr Inspection	None
57	120V/208V/P-249	NS/-	No	Periodic Space Htr Inspection	None
58	480/120V MCC-2A2	NS/NA	No	Failure of Indication	2B2
59	480/120V MCC-2B2	NS/NB	No	Failure of Indication	2A2
60	480/120V MCC-2B6	IE/SB	No	Failure of Indication	2A6
61	120V ac PP-266	IE/SA	Yes	Ann & Fail of Indication	120V ac PP-267
62	120V ac PP-267	IE/SB	Yes	Ann & Fail of Indication	120V ac PP-266
63	125V dc Bus 2AA	IE/SA	Yes	Ann & Fail of Indication	125V dc Bus 2BB

TABLE 15.0-21

ALARM INDICATION FOR LOSS OF POWER
TO SAFETY AND NON-SAFETY POWER BUS

Item	Bus or Distr. Panel	Class	Dedicated Alarm	Bus Failure Detection	Redundant Bus
64	125V dc Bus 2BB	IE/SB	Yes	Ann & Fail of Ind	125V dc Bus 2AA
65	125V dc PP-254	IE/SA	No	Fail of Ind & Cont	125V dc PP-255
66	125V dc PP-255	IE/SB	No	Fail of Ind & Cont	125V dc PP-254
67	120/208V PP-268	IE/SA	No	Fail of Ind & Cont	120/208V PP-269
68	120/208V PP-269	IE/SB	No	Fail of Ind & Cont	120/208V PP-268
69	120V Instrument Bus MA-1	IE/MA	Yes	Ann & Fail of Ind	Redundant to Each Other
70	120V Instrument Bus MB-1	IE/MB	Yes	Ann & Fail of Ind	
71	120V Instrument Bus MC-1	IE/MCs	Yes	Ann & Fail of Ind	
72	120V Instrument Bus MD-1	IE/MD	Yes	Ann & Fail of Ind	

TABLE 15.0-22

COMMON LINE SENSORS

Cycle 1

Common Tap	Instrument	Function*
Pressurizer		
1-RC-107	PT-1106	S
	PT-1102-D	S
	LT-1104	Indicate only
	LT-1103	Indicate only
1-RC-130 (3/4-RC-171)	LT-1110-Y	P/S
	LT-1104	Indicate only
	LT-1103	Indicate only
1-RC-130 (3/4-RC-290)	LT-1110-Y	P/S
	PT-1100-Y	P
	PT-1102-B	S
	PT-1105	S
	PT-1107	S
1-RC-105 (3/4-RC-169)	LT-1110-X	P/S
	LT-1105	Indicate only
1-RC-104	PT-1104	S
	PT-1102-C	S
1-RC-105 (3/4-RC-289)	LT-1110-X	P/S
	LT-1105	Indicate only
	PT-1100-X	P
	PT-1102-A	S
	PT-1108	S
	PT-1103	S
RCS Loop A		
3/4-RC-132	PDT-1111-A	S
	PDT-1124-X	Indicate & Record
	PDT-1124-W	Indicate & Record
1-RC-220	PDT-1112	Indicate & Record
	PDT-1124-X	Indicate & Record
1-RC-218	PDT-1110	Indicate & Record
	PDT-1124-W	Indicate & Record

*P = process,
S = safety

TABLE 15.0-22 (Cont'd)

Common Tap	Instrument	Function*
RCS Loop B		
3/4-RC-127	PDT-1121-C	S
	PDT-1124-Z	Indicate & Record
	PDT-1124-Y	Indicate & Record
1-RC-224	PDT-1122	Indicate & Record
	PDT-1124-Z	Indicate & Record
1-RC-222	PDT-1120	Indicate & Record
	PDT-1124-Y	Indicate & Record
S/G A		
1-1"-MSL-100	LT-9013-A	S
	LT-9011	P
	PT-8013-A	S
1-1"-MSL-101	LT-9013-A	S
	LT-9011	P
1-1"-MSL-102	PT-8013-B	S
	LT-9013-B	S
1-1"-MSL-104	PT-8113	Indicate only
	PT-8013-C	S
	LT-9013-C	S
1-1"-MSL-106	PT-8013-D	S
	LT-9005	P
	LT-9013-D	S
	LT-9113	Indicate only
	LT-9012	Indicate only
1-1"-MSL-107	LT-9005	P
	LT-9013-D	S
1-1"-MSL-116	LT-9113	Indicate only
	LT-9012	Indicate only

*P = process
S = safety

TABLE 15.0-22 (Cont'd)

Common Tap	Instrument	Function*
S/G B		
I-1"-MSL-108	LT-9023-A	S
	PT-8023-A	S
	LT-9021	P
I-1"-MSL-109	LT-9023-A	S
	LT-9021	P
I-1"-MSL-110	PT-8023-B	S
	LT-9023-B	S
I-1"-MSL-112	PT-8123	Indicate only
	LT-9023-C	S
	PT-8023-C	S
I-1"-MSL-114	PT-8023-D	S
	LT-9006	P
	LT-9023-D	S
	LT-9022	Indicate only
	LT-9123	Indicate only
I-1"-MSL-115	LT-9006	P
	LT-9023-D	S
I-1"-MSL-117	LT-9022	Indicate only
	LT-9123	Indicate only

*P = process
S = safety

TABLE 15.0-23

EGP1OO1 Relay S/N 80411508

120V ac/60 Hz Coil

Connections	Voltage		Current	
Between Terminals	AC (RMS)	DC	AC	DC
B4 to B2	5,000	5,000	120ua	.055ua
B4 to T4	5,000	5,000	120ua	.065ua
B4 to M2	4,300	5,000	*	.065ua
B4 to R2	4,300	5,000	*	.060ua
B4 to R4	4,200	5,000	*	.070ua
B4 to M4	4,300	5,000	*	.075ua
B4 to T4	4,300	5,000	*	.065ua
B4 to B3	5,000	5,000	120ua	.050ua
B4 to T3	5,000	5,000	120ua	.060ua
B4 to M3	4,000	5,000	*	.050ua
B4 to R3	3,900	5,000	*	.050ua
B4 to R1	3,800	5,000	*	.065ua
B4 to Ml	3,800	5,000	*	.065ua
B4 to T1	4,500	5,000	*	.070ua
B4 to B1	not** tested	not** tested		
B1 to T1	4,400	5,000	*	.060ua
B1 to M1	3,800	51000	*	.065ua
B1 to R1	3,800	5,000	*	.060ua
B1 to R3	4,100	5,000	*	.050ua
B1 to M3	4,000	5,000	*	.055ua
B1 to T3	5,000	5,000	120ua	.060ua
B1 to B3	5,000	5,000	120ua	.045ua
B1 to T4	4,500	5,000	120ua	.055ua
B1 to M4	3,900	5,000	*	.075ua
B1 to R4	4,000	5,000	*	.070ua
B1 to R2	4,200	5,000	*	.060ua
B1 to M2	4,000	5,000	*	.060ua
B1 to T2	5,000	5,000	120ua	.065ua
B1 to B2	5,000	5,000	120ua	.055ua
B1 to B4	not** tested	not** tested		

* Indicates current exceeded 5.5 milliamperes

** B4 to BI relay coil

TABLE 15.0-24

EGPDC01 Relay S/N 80411510

125V dc Coil

Connections	Voltage		Current	
Between Terminals	AC (RMS)	DC	AC	DC
B4 to B2	5,000	5,000	100ua	.10ua
B4 to T2	5,000	5,000	100ua	.10ua
B4 to M2	4,200	5,000	*	.095ua
B4 to R2	4,300	5,000	*	.095ua
B4 to R4	4,000	5,000	*	.120ua
B4 to M4	3,900	5,000	*	.115ua
B4 to T4	4,200	5,000	*	.110ua
B4 to B3	5,000	5,000	80ua	.090ua
B4 to T3	5,000	5,000	100ua	.110ua
B4 to M3	4,200	5,000	*	.115ua
B4 to R3	3,900	5,000	*	.105ua
B4 to R1	3,600	5,000	*	.120ua
B4 to M1	3,600	5,000	*	.120ua
B4 to T1	4,400	5,000	*	.115ua
B4 to B1	not** tested	not** tested		
B1 to T1	4,400	5,000	*	.130ua
B1 to M1	3,500	5,000	*	.125ua
B1 to R1	3,500	5,000	*	.120ua
B1 to R3	3,900	5,000	*	.110ua
B1 to M3	3,900	5,000	*	.105ua
B1 to T3	5,000	5,000	120ua	.100ua
B1 to B3	5,000	5,000	100ua	.095ua
B1 to T4	4,200	5,000	*	.105ua
B1 to M4	4,000	5,000	*	.120ua
B1 to R4	4,200	5,000	*	.125ua
B1 to R2	4,500	5,000	*	.095ua
B1 to M2	4,300	5,000	*	.095ua
B1 to T2	5,000	5,000	120ua	.100ua
B1 to B2	5,000	5,000	110ua	.110ua
B1 to B4	not** tested	not** tested		

*Indicates current exceeded 5.5 milliamperes

**B4 to B1 relay coil

TABLE 15.0-25

COMPARISON OF MAXIMUM POST-TRIP FISSION POWERS, MAXIMUM POST-TRIP REACTIVITIES, AND MINIMUM POST-TRIP DNBR WITH AND WITHOUT AUTOMATIC INITIATION OF AUXILIARY FEEDWATER FOR A 6.36 FT^2 MAIN STEAM LINE BREAK INITIATED AT FULL POWER, INSIDE CONTAINMENT, WITH & LOSS OF OFFSITE POWER, A HPSI PUMP FAILURE, AND A STUCK CEA

CYCLE 1

	Manual AFW	Automatic AFW
Time of auxiliary feedwater actuation (minutes after trip)	10	0
Maximum post-trip core average power (% of 2570 MW)	8.0	8.3
Maximum post-trip reactivity (10^{-2} $\Delta\rho$)	-0.003	+0.003
Minimum post-trip DNBR	1.75	1.66

Table 15.0-26 - EPU Nuclear Steam Supply System Power Ratings	
Rated Reactor Core Thermal Power Output, MWt	3020
NSSS Rated Thermal Power, MWt	3034
Thermal Power Generated by the Reactor Coolant Pumps, MWt	
Nominal (total, 4 pumps in operation)	14
Maximum (total, 4 pumps in operation)	20

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Table 15.0-27 - Summary of Initial Non-LOCA Conditions and Computer Codes Used - AREVA							
Event	Principal Computer Codes Used	DNB Correlation	Statistical DNB Method	Initial Nominal Core Power	Initial RCS Flow Rate (gpm)	Initial Nominal Core Inlet Temp. (°F)	Initial Nominal Pressurizer Pressure (psia)
Decrease in Feedwater Temperature	S-RELAP5 XCOBRA-IIIC	HTP	No	100%	370000	551	2250
Increase in Feedwater Flow	S-RELAP5 XCOBRA-IIIC	HTP	No	100%	370000	551	2250
Increase in Steam Flow	S-RELAP5 XCOBRA-IIIC	HTP	No	100% HZP	370000	551 532	2250
Pre-Trip Steam System Piping Failure	S-RELAP5 XCOBRA-IIIC	HTP	Yes	100%	370000	551	2250
Post-Trip Steam System Piping Failure	S-RELAP5 XCOBRA-IIIC PRISM	Biasi	No	100% HZP	370000	551 532	2250
Loss of Condenser Vacuum	S-RELAP5 XCOBRA-IIIC	HTP	No	100%	370000	551	2250
Transients Resulting from the Malfunction of One Steam Generator	S-RELAP5 XCOBRA-IIIC	HTP	No	100%	370000	551	2250

Table 15.0-27 - Summary of Initial Non-LOCA Conditions and Computer Codes Used (continued)- AREVA							
Loss of Forced Reactor Coolant Flow	S-RELAP5 XCOBRA-IIIC	HTP	Yes	100%	370000	551	2250
Reactor Coolant Pump Rotor Seisure	S-RELAP5 XCOBRA-IIIC	HTP	Yes	100%	370000	551	2250
Uncontrolled CEA Withdrawal from a Subcritical or Low Power Startup	S-RELAP5 XCOBRA-IIIC	HTP	No	HZP	370000	532	2250
Uncontrolled CEA Withdrawal at Power	S-RELAP5 XCOBRA-IIIC	HTP	Yes	100% 65% 20%	370000	551 544.4 535.8	2250
CEA Drop	S-RELAP5 XCOBRA-IIIC	HTP	No	100%	370000	551	2250
CEA Ejection	S-RELAP5 XCOBRA-IIIC	HTP	Yes	100% 65% 20% HZP	370000	551 544.4 535.8 532	2250
Inadvertent Opening of a Pressurizer Pressure Relief Valve	S-RELAP5 XCOBRA-IIIC	HTP	Yes	100%	370000	551	2250

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Table 15.0-27a - Summary of Initial Conditions and Computer Codes (Sheet 1 of 6) - Westinghouse

	EVENT	COMPUTER CODES USED	MODERATOR DENSITY COEFFICIENT (Δk/gm/cc)	MODERATOR TEMPERATURE COEFFICIENT (pcm/°F)	DOPPLER FEEDBACK	DNB CORRELATION	REVISED THERMAL DESIGN PROCEDURE	INITIAL CORE THERMAL POWER (MWt)
15.1	Increase in Heat Removal by the Secondary System							
	Decrease in Feedwater Temperature	RETRAN	0.43	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Increase in Feedwater Flow Rate	RETRAN	0.43	See Figure 15.0.5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Excessive Increase in Main Steam Flow	RETRAN	N/A	See Figure 15.0.5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Inadvertent Opening of a S/G Relief or Safety Valve	RETRAN	N/A	See Figure 15.0.5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Pre-Trip Steamline Break with Failure of the Fast Bus Transfer (FFBT)	RETRAN VIPRE, ANC	0.0 - 0.43	See Figure 15.0.5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Pre-Trip Steamline Break Coincident with Loss of Offsite Power (LOOP)	RETRAN VIPRE, ANC	0.30	See Figure 15.0.5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Post-Trip Steamline Break	RETRAN VIPRE, ANC	See Figure 15.1.6-1	-4.5	See Figure 15.1.6-2	ABB-NV	No	0 (subcritical)
15.2	Decrease in Heat Removal by the Secondary System							
	Loss of Condenser Vacuum – Overpressure Case	RETRAN	N/A	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	N/A	No	3030
	Loss of Condenser Vacuum – DNB Case	RETRAN VIPRE	N/A	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Loss of Non-Emergency AC to the Station Auxiliaries	Bounded by 15.2.3, 15.3.2	N/A	N/A	N/A	N/A	N/A	N/A
	Loss of Normal Feedwater Flow	Bounded by 15.2.3, 15.3.2	N/A	N/A	N/A	N/A	N/A	N/A
	Feedwater System Pipe Rupture – RCS Overpressure Case	RETRAN	N/A	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	N/A	No	3030
	Feedwater System Pipe Rupture – MSS Overpressure Case	RETRAN	N/A	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	N/A	No	3030
	Asymmetric Steam Generator Transient	RETRAN	0.43	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020

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Table 15.0-27a - Summary of Initial Conditions and Computer Codes (Sheet 2 of 6) - Westinghouse

	EVENT	REACTOR COOLANT PUMP HEAT (MWt)	REACTOR VESSEL FLOW RATE (gpm)	VESSEL T-avg (°F)	PRESSURIZER PRESSURE (psia)	PRESSURIZER WATER LEVEL (%)	FEEDWATER TEMP. (°F)	S/G TUBE PLUGGING LEVEL (%)
15.1	Increase in Heat Removal by the Secondary System							
	Decrease in Feedwater Temperature	14.2	390,000	578.5	2225	63.0	441.0	0
	Increase in Feedwater Flow Rate	14.2	390,000	578.5	2225	63.0	441.0	0
	Excessive Increase in Main Steam Flow	14.2	390,000	578.5	2225	63.0	441.0	0
	Inadvertent Opening of a S/G Relief or Safety Valve	14.2	390,000	578.5	2225	63.0	441.0	0
	Pre-Trip Steamline Break with FFBT	14.2	390,000	578.5	2225	63.0	441.0	0
	Pre-Trip Steamlnie Break Coincident with LOOP	14.2	390,000	578.5	2225	63.0	441.0	0
	Post-Trip Steamline Break	14.2	375,000	532.0	2225	33.1	70.0	0
15.2	Decrease in Heat Removal by the Secondary System							
	Loss of Condenser Vacuum – Overpressure Case	14.2	375,000	560.0	2180	66.0	441.0	10
	Loss of Condenser Vacuum – DNB Case	14.2	390,000	578.5	2225	66.0	441.0	10
	Loss of Non-Emergency AC to the Station Auxiliaries	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Loss of Normal Feedwater Flow	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Feedwater System Pipe Rupture – RCS Overpressure Case	14.2	375,000	560.0	2180	66.0	441.0	10
	Feedwater System Pipe Rupture –MSS Overpressure Case	14.2	375,000	581.5	2180	66.0	441.0	0
	Asymmetric Steam Generator Transient	14.2	390,000	578.5	2225	66.0	441.0	0 or 10

Table 15.0-27a - Summary of Initial Conditions and Computer Codes (Sheet 3 of 6) - Westinghouse

	EVENT	COMPUTER CODES USED	MODERATOR DENSITY COEFFICIENT (Δk/gm/cc)	MODERATOR TEMPERATURE COEFFICIENT (pcm/°F)	DOPPLER FEEDBACK	DNB CORRELATION	REVISED THERMAL DESIGN PROCEDURE	INITIAL CORE THERMAL POWER (MWt)
15.3	Decrease in RCS Flow Rate							
	Partial/Complete Loss of Forced Flow	RETRAN VIPRE	N/A	See Figure 15.0-5a	Lower Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Reactor Coolant Pump Seized Rotor/Shaft Break – DNB Case	RETRAN VIPRE	N/A	See Figure 15.0-5a	Lower Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Reactor Coolant Pump Seized Rotor/Shaft Break – Overpressure/PCT Case	RETRAN	N/A	See Figure 15.0-5a	Lower Curve of Figure 15.0-4a	N/A	No	3030
15.4	Reactivity and Power Distribution Anomalies							
	Uncontrolled CEA Bank Withdrawal from Subcritical	TWINKLE FACTRAN VIPRE	N/A	5.0	900 pcm	ABB-NV	No	0 (subcritical)
	Uncontrolled CEA Bank Withdrawal at Power	RETRAN	0.0 to 0.43	See Figure 15.0-5a	Upper & Lower Curve of Figure 15.0-4a	ABB-NV	Yes - DNBR No - RCS Peak Pressure	3020
	CEA Misoperation (Dropped Rod)	RETRAN VIPRE, ANC	N/A	0.0 to –35.0	Lower Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Startup of an Inactive Loop at an Incorrect Temperature	Precluded by Technical Specifications	N/A	N/A	N/A	N/A	N/A	N/A
	Chemical and Volume Control System (CVCS) Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant	ABORTV1	N/A	N/A	N/A	N/A	N/A	N/A
	CEA Ejection	TWINKLE FACTRAN	N/A	See Note 1	900 pcm	N/A	No	0 & 3030

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Table 15.0-27a - Summary of Initial Conditions and Computer Codes (Sheet 4 of 6) - Westinghouse

	EVENT	REACTOR COOLANT PUMP HEAT (MWt)	REACTOR VESSEL FLOW RATE (gpm)	VESSEL T-AVG (°F)	PRESSURIZER PRESSURE (psia)	PRESSURIZER WATER LEVEL (%)	FEEDWATER TEMP. (°F)	SG TUBE PLUGGING LEVEL (%)
15.3	Decrease in RCS Flow Rate							
	Partial/Complete Loss of Forced Flow	14.2	390,000	578.5	2225	63.0	441.0	10
	Reactor Coolant Pump Seized Rotor/Shaft Break – DNB Case	14.2	390,000	578.5	2225	63.0	441.0	10
	Reactor Coolant Pump Seized Rotor/Shaft Break – Overpressure/PCT Case	14.2	375,000	581.5	2395	66.0	441.0	10
15.4	Reactivity and Power Distribution Anomalies							
	Uncontrolled CEA Bank Withdrawal from Subcritical	N/A	375,000	532.0	2180	N/A	N/A	N/A
	Uncontrolled CEA Bank Withdrawal at Power	14.2	390,000	578.5	2225	63.0	441.0	10
	CEA Misoperation (Dropped Rod)	14.2	390,000	578.5	2225	63.0	441.0	0
	Startup of an Inactive Loop at an Incorrect Temperature	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	CVCS Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant	N/A	N/A	581.5 532.0	2250	N/A	N/A	10
	CEA Ejection (1)	N/A	375,000	581.5 532.0	2180.0	N/A	N/A	N/A

Table 15.0-27a - Summary of Initial Conditions and Computer Codes (Sheet 5 of 6) - Westinghouse

	EVENT	COMPUTER CODES USED	MODERATOR DENSITY COEFFICIENT (Δk/gm/cc)	MODERATOR TEMPERATURE COEFFICIENT (pcm/°F)	DOPPLER FEEDBACK	DNB CORRELATION	REVISED THERMAL DESIGN PROCEDURE	INITIAL CORE THERMAL POWER (MWt)
15.5	Increase in Coolant Inventory							
	Inadvertent Emergency Core Cooling System (ECCS) Operation at Power	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	CVCS Malfunction	RETRAN	0.43	-2.9	Lower Curve of Figure 15.0-4a	N/A	No	3030
15.6	Decrease in Coolant Inventory							
	Inadvertent RCS Depressurization	RETRAN	N/A	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	ABB-NV	Yes	3020
	Steam Generator Tube Rupture	RETRAN	0.0	See Figure 15.0-5a	Upper Curve of Figure 15.0-4a	N/A	No	3030
	Loss of coolant accidents	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5	See Section	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5
	Primary Line Break Outside Containment	RETRAN	N/A	N/A	N/A	N/A	No	3030

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Table 15.0-27a - Summary of Initial Conditions and Computer Codes (Sheet 6 of 6) - Westinghouse

	EVENT	REACTOR COOLANT PUMP HEAT (MWt)	REACTOR VESSEL FLOW RATE (gpm)	VESSEL T-AVG (°F)	PRESSURIZER PRESSURE (psia)	PRESSURIZER WATER LEVEL (%)	FEEDWATER TEMP. (°F)	SG TUBE PLUGGING LEVEL (%)
15.5	Increase in Coolant Inventory							
	Inadvertent ECCS Operation at Power	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	CVCS Malfunction	20.0	375,000	581.5	2180	60.0	441.0	10
15.6	Decrease in Coolant Inventory							
	Inadvertent RCS Depressurization	14.2	390,000	578.5	2225	63.0	441.0	10
	Steam Generator Tube Rupture	20.0	375,000	581.5	2395	71.0	441.0	10
	Loss of Coolant Accidents	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5	See Section 15.6.5
	Primary Line Break Outside Containment	20.0	375,000	581.5 560.0	2395	71.0	441.0	10

Notes:

1. The following moderator temperature coefficient (MTC) and isothermal temperature coefficient (ITC) values were assumed in the analysis of the CEA Ejection event:

   BOL, HZP MTC = 5.0 pcm/°F
   BOL, HFP MTC = 0.0 pcm/°F
   EOL, HZP ITC = -5.0 pcm/°F
   EOL, HFP ITC = -20.0 pcm/°F

Table 15.0-28 - Nominal Values of Pertinent Plant Parameters Used in Accident Analyses - AREVA		
RPS Trip Function	Hi-Tavg	Low Tavg
NSSS Thermal Power (MWt)[1]	3040	3040
Reactor Core Power (MWt)[2]	3020	3020
HFP core inlet temperature (°F)	551.0	535.0
HFP vessel average temperature (°F)	578.5	563.0
Zero load temperature (°F)	532.0	532.0
Pressurizer pressure (psia)	2250	2250
Total reactor vessel inlet flow rate (gpm)[3]	370,000	370,000
Steam flow from NSSS (Mlbm/hr)	13.247	13.247
SG pressure (psia)	Note 4	Note 4
Feedwater temperature (°F)	441.0	441.0
Maximum averaqe SG tube pluqqinq (%)	20	20

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1. Includes maximum reactor coolant pump heat (MWt). Nominal pump heat is 14.2 MWt.
2. Power measurement uncertainty not included.
3. Minimum measured flow of 382,500 gpm with 12,500 gpm for uncertainty.
4. Analysis full power SG pressure range is 810 psia to 920 psia.

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Table 15.0-28a - Nominal Values of Pertinent Plant Parameters Utilized in the Accident Analyses - Westinghouse								
Equivalent Steam Generator Tube Plugging Level (all loops)	Pre-EPU Hi-T_{avg}		Pre-EPU Lo-T_{avg}		EPU Hi-T_{avg}		EPU Lo-T_{avg}	
	0%	30%	0%	30%	0%	10%	0%	10%
NSSS Thermal Power (MWt)[1]	2720	2720	2720	2720	3040	3040	3040	3040
Reactor Core Power (MWt)[2]	2700	2700	2700	2700	3020	3020	3020	3020
HFP core inlet temperature (°F)	549.0	549.0	535.0	535.0	551.0	551.0	535.0	535.0
HFP vessel average temperature (°F)	576.5	576.5	563.0	563.0	578.5	578.5	563.0	563.0
Zero Load Temperature (°F)	532.0	532.0	532.0	532.0	532.0	532.0	532.0	532.0
Pressurizer Pressure (psia)	2250	2250	2250	2250	2250	2250	2250	2250
Total Reactor Vessel Inlet Flow (thermal design, GPM)[3]	335,000	335,000	335,000	335,000	375,000	375,000	375,000	375,000
Total Reactor Coolant Flow (10^6lb/hr)	126.1	126.1	128.4	128.4	140.8	140.8	143.8	143.8
Steam Flow from NSSS (10^6lb/hr)	11.87	11.83	11.82	11.79	13.42	13.41	13.36	13.35
Steam Pressure at Steam Generator (psia)	857	766	755	672	895	873	775	756
Maximum Steam Moisture Content (%)	0.25	.025	0.25	0.25	0.10	0.10	0.10	0.10
Assumed Feedwater Temperature at Steam Generator Inlet (°F)	435.0	435.0	435.0	435.0	441.0	441.0	441.0	441.0

Notes:

1. Includes maximum reactor coolant pump heat (20 MWt). Nominal pump heat is 14.2 MWt.
2. Power measurement uncertainty not included.
3. Minimum measured flow is 349,500 gpm for 30% SGTP, minimum measured flow is 390,000 gpm for EPU.

Table 15.0-29 - Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times - AREVA				
RPS Trip Function	Allowable Trip Setpoint	Uncertainty	Harsh Condition Uncertainty	Response Time (sec)
Variable Power Level - High(1) Four Reactor Coolant Pumps Operating	≤ 9.61% above thermal power with a minimum setpoint of 15% RTP and a maximum of ≤ 107.0% RTP	Note (2)	N/A	≤ 0.4(3) (excluding RTD delay time)
Thermal Margin/Low Pressure (TM/LP)(1)	PVAR = f(T_{IN}, Power, ASI) Min. floor = 1900 psia	±160 psi	N/A	≤ 0.9 (excluding RTD delay time)
Reactor Coolant Flow - Low(1)	≥ 94.9% of four pump design reactor coolant flow(4)	±3.5%	±7.5%	≤ 0.9
Pressurizer Pressure- High	≤ 2374 psia	±45 psi	±90 psi	≤ 1.15
Steam Generator Pressure - Low	≥ 621 psia	±40 psi	±80 psi	≤ 1.15
Steam Generator Pressure Difference - High(1)	≤ 132 psi	±60 psi	±115 psi	≤ 1.15
Containment Pressure - High	≤ 3.1 psi	N/A	±0.55 (pressure measurement uncertainy) ±1.65 psi (trip uncertainty)	≤ 1.15

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Table 15.0-29 - Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times (continued) - AREVA				
ESF Actuation	Allowable Actuation Setpoint	Uncertainty	Harsh Condition Uncertainty	Response Time (sec)
Main Stream Isolation 1. SG Pressure - Low	≥ 567 psia	Not used	±80 psi	≤ 7.0(5)(6)
Feedwater Isolation • SG Pressure - Low	≥ 567 psia	Not used	±80 psi	≤ 5.65(5)(6)
Auxiliary Feedwater Isolation • High SG Differential Pressure	≤ 275 psia	Not used	±125 psi	≤ 200
Safety Injection • Pressurizer Pressure- Low	≥ 1728 psia	Not used	±90 psi	≤ 30(5) ≤ 20(6)

1. Trip may be bypassed below 0.5% RTP; bypass is automatically removed when Wide Range Logarithmic Neutron Flux power is > 0.5% RTP.
2. Minimum uncertainty is 5% at ≥75% RTP and a maximum of 12% for power levels ≤ 25% RTP, when combined with power measurement uncertainty. The uncertainty is linear between 25% and 75% power.
3. Additional delay of 0.7 sec. added for events initiated at power levels less than or equal to 1% RTP.
4. Minimum analytical reactor coolant flow with 4 pumps operating is 370000 gpm after accounting for measurement uncertainty.
5. Diesel generator starting time and sequence loading delays included.
6. Diesel generator starting time and sequence loading delays not included (offsite power available).

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Table 15.0-29a - Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times (Sheet 1 of 2) - Westinghouse		
RPS Trip Function	Technical Specification Value	Analysis Setpoint
Variable Power Level – High (% Above Initial Power Level)	9.61	11.7RTP>35%<100% 13.6 RTP≤35%
Variable Power Level – Ceiling (% Rated Thermal Power)	107.0	112.0(1)
Variable Power Level – Floor (% Rated Thermal Power)	15.0	24.5
Pressurizer Pressure – High (psia) Normal Environment Harsh Environment(2)	2370	2415 2460
Pressurizer Pressure - Low (Floor of Thermal Margin/Low Pressure),(psia) Normal Environment Harsh Environment(2)	1900	1855 1810
Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment(2)	626	586 546
Steam Generator Pressure – High Difference, (psid)	120	230
Steam Generator Level – Low (% Narrow Range Tap Span)	20.5(7)	1.0
Reactor Coolant Flow – Low (% of Thermal Design Flow)	95.4	Normal 88.4(3) Harsh 84.5(3)
Containment Pressure – High (psig) (6)	3.0	4.65
Thermal Margin/Low Pressure (psig)	Tech. Spec. Table 2.1-1	Variable, See Figure 15.0-3
Engineering Safety Feature Actuation System (ESFAS) Function		
Safety Injection Actuation Signal (SIAS) on Pressurizer Pressure – Low (psia) Normal Environment Harsh Environment(2)	1736	1683 1638
Main Steam Line Isolation Signal (MSIS) on Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment(2)	600	527 487
Main Feedwater Isolation on Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment(2)	600	527 487
Auxiliary Feedwater Isolation On Steam Generator Pressure Difference – High (psid)	275	441

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Table 15.0-29a - Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times (Sheet 2 of 2) - Westinghouse			
RPS Trip Function	Sensor Response Time Constant (sec)	Processing Delay (sec)	Total Delay Time (sec)
Variable High Power Excore Neutron Power detectors Hot-Leg and Cold-Leg RTDs (Thermal power calculation)	 <0.01[4] 8.0	0.4	 0.4 8.4
Pressurizer Pressure – High	0.75	0.4	1.15
Thermal Margin/Low Pressure Pressurizer Pressure Hot-Leg and Cold-Leg RTDs (Thermal power calculation) Excore Neutron Power detectors (ASI calculation)	 0.75 8.0 N/A	0.4	 1.15 8.4 -
Steam Generator Pressure – Low	0.75	0.4	1.15
Steam Generator Pressure – High Difference	0.75	0.4	1.15
Steam Generator Level – Low	0.75	0.4	1.15
Reactor Coolant Flow – Low	0.50	0.4	0.90
Containment Pressure – High (psig) [6]	0.75	0.4	1.15
ESFAS Function			Total Delay Time (sec)
Pressurizer Pressure – Low (SI) → To achieve full SI flowrate			30.0[5]
Steam Generator Pressure – Low → To complete MSIV closure			6.75
Steam Generator Pressure – Low → To complete MFIV closure			5.15
Auxiliary Feedwater Isolation On Steam Generator Pressure Difference – High →To complete auxiliary feedwater isolation to affected SG			120

Notes:

1. Rod shadowing and downcomer temperature decalibration effects on excore detector signals are applied independently.
2. Harsh environment setpoints apply to inside containment steamline and feedwater line breaks and LOCAs.
3. Setpoint is equivalent to 91.9% of Thermal Design Flow (normal environment) & 87.9% (harsh environment). The values shown are based on minimum measured flow.
4. Typical response time is 50 μ seconds.
5. Response time for loss of offsite power, 20.0 second response time with power available.
6. Not used for Non-LOCA safety analyses.
7. The EPU Technical Specification value has been increased to 35% NR. This setpoint is not credited in the accident analyses.

Table 15.0-30 (Sheet 1 of 4) Plant Systems and Equipment Available for Transient and Accident Mitigation					
	Event	**Reactor Trip Functions**	**ESF Actuation Functions**	**Other Equipment/Alarms**	**ESF Equipment**
15.1	Increase in Heat Removal by the Secondary System				
	Decrease in Feedwater Temperature	Variable High Power Thermal Margin / Low Pressure Low SG Pressure	Main Steam Isolation Signal (MSIS)	Main Steam Safety Valves (MSSVs) , Main Steam Isolation Valves (MSIVs)	___
	Increase in Feedwater Flow Rate	Variable High Power Thermal Margin / Low Pressure Low SG Pressure Reactor Trip on Turbine Trip	MSIS	Hi-Hi SG Level Trip, MSSVs, MSIVs	___
	Excessive Increase in Main Steam Flow	Variable High Power, Thermal Margin/Low Pressure	___	___	___
	Inadvertent Opening of a S/G Relief or Safety Valve	Variable High Power, Low SG Pressure, Low SG Level, High SG Delta-P, Thermal Margin/Low Pressure TM/LP-Low Pressure	Main Feedwater Isolation Signal (MFIS), MSIS, AFW on low SG Level, AFW Isolation to the faulted SG on High SG or Main Feedwater Line Delta-P	Main Feedwater Isolation Valves (MFIVs), MSIVs	Emergency Core Cooling System (ECCS), Auxiliary Feedwater Syatem (AFW)
	Pre-Trip Steamline Break	Variable High Power, Low SG Pressure, Low SG Level, High SG Delta-P, Thermal Margin/Low Pressure, TM/LP-Low Pressure, Low RCS Flow	Main Feedwater Isolation Signal (MFIS), MSIS, AFW on low SG Level, AFW Isolation to the faulted SG on High SG or Main Feedwater Line Delta-P	Main Feedwater Isolation Valves (MFIVs), MSIVs	Emergency Core Cooling System (ECCS), Auxiliary Feedwater Syatem (AFW)
	Post-Trip Steamline Break	N/A, Event initiated from hot zero power conditions	Main Feedwater Isolation Signal (MFIS), MSIS, AFW on low SG Level, AFW Isolation to the faulted SG on High SG or Main Feedwater Line Delta-P	Main Feedwater Isolation Valves (MFIVs), MSIVs	Emergency Core Cooling System (ECCS), Auxiliary Feedwater Syatem (AFW)

Table 15.0-30 (Sheet 2 of 4) Plant Systems and Equipment Available for Transient and Accident Mitigation					
	Event	**Reactor Trip Functions**	**ESF Actuation Functions**	**Other Equipment/Alarms**	**ESF Equipment**
15.2	Decrease in Heat Removal by the Secondary System				
	Loss of Condenser Vacuum – Overpressure Case	High Pressurizer Pressure, Thermal Margin / Low Pressure, Low Steam Generator Level	___	Pressurizer Safety Valves (PSVs), MSSVs	___
	Loss of Condenser Vacuum – DNB Case	High Pressurizer Pressure, Thermal Margin / Low Pressure, Low Steam Generator Level	___	PSVs, MSSVs	___
	Loss of Non-Emergency AC to the Station Auxiliaries	Reactor Coolant Flow - Low	Auxiliary Feedwater Actuation Signal	PSVs, MSSVs	Auxiliary Feedwater System
	Loss of Normal Feedwater Flow	High Pressurizer Pressure Low Steam Generator Level	Auxiliary Feedwater Actuation Signal	PSVs, MSSVs	Auxiliary Feedwater System
	Feedwater System Pipe Rupture	High Pressurizer Pressure, Low Steam Generator Pressure, Low Steam Generator Level, Thermal Margin/Low Pressure, High Steam Generator Delta-P	Auxiliary Feedwater Actuation Signal	PSVs, MSSV, MSIVs, MFIVs	Auxiliary Feedwater System
	Asymmetric Steam Generator Transient	High Steam Generator Delta-P, Low Steam Generator Pressure, Low Steam Generator Level	___	PSVs, MSSVs	___

Table 15.0-30 (Sheet 3 of 4) Plant Systems and Equipment Available for Transient and Accident Mitigation					
	Event	**Reactor Trip Functions**	**ESF Actuation Functions**	**Other Equipment/Alarms**	**ESF Equipment**
15.3	Decrease in RCS Flow Rate				
	Partial/Complete Loss of Forced Flow	Low RCS flow	---	Steam dump and bypass system	---
	Reactor Coolant Pump Seized Rotor/Shaft Break	Low RCS flow	---	Steam dump and bypass system	---
15.4	Reactivity and Power Distribution Anomalies				
	Uncontrolled CEA Bank Withdrawal from Subcritical	Variable High Power Rate-of-Change of Power - High	___	___	___
	Uncontrolled CEA Bank Withdrawal at Power	Variable High Power, High Pressurizer Pressure, Thermal Margin / Low Pressure	___	MSSVs, PSVs	___
	CEA Misoperation (Dropped Rod)	Variable High Power, TM/LP – Low Pressure, Low SG Pressure	___	___	___
	Startup of an Inactive Loop at an Incorrect Temperature	N/A, Event precluded by administrative controls	___	___	___
	CEA Ejection	Variable High Power Rate-of-Change of Power - High	___	___	___

Table 15.0-30 (Sheet 4 of 4) Plant Systems and Equipment Available for Transient and Accident Mitigation					
	Event	**Reactor Trip Functions**	**ESF Actuation Functions**	**Other Equipment/Alarms**	**ESF Equipment**
15.5	Increase in Coolant Inventory				
	Inadvertent ECCS Operation at Power	N/A, Event precluded by ECCS design	___	___	___
	CVCS Malfunction	High Pressurizer Pressure	___	Pressurizer High Level Alarm PSVs	___
15.6	Decrease in Coolant Inventory				
	Inadvertent RCS Depressurization	TM/LP - Low Pressure	___	___	___
	Steam Generator Tube Rupture	TM/LP - Low Pressure	SIAS	MSSVs	HPSI
	Loss of coolant accidents	TM/LP - Low Pressure	SIAS, RAS, CIAS, CSAS	Chemical and Volume Control System	HPSI, LPSI, CS, SDCS, Fan Coolers
	Primary Line Break	TM/LP - Low Pressure	SIAS	Letdown isolation	___

Table 15.0-31 Accident Analysis Single Failure Assumptions	
Event	**Single Failure Assumption**
15.1 Increase in Heat Removal by the Secondary System	
Decrease in Feedwater Temperature	One Protection System Train
Increase in Feedwater Flow Rate	One Protection System Train
Excessive Increase in Main Steam Flow	Bounded by other events
Inadvertent Opening of a S/G relief or Safety Valve	Bounded by other events
Pre-Trip Steamline Break	One Protection System Train (Failure of Fast Bus Transfer Considered)
Post-Trip Steamline Break	One Safety Injection Train
15.2 Decrease in Heat Removal by the Secondary System	
Loss of Condenser Vacuum	One Protection System Train
Loss of Non-Emergency AC to the Station Auxiliaries	Bounded by other events
Loss of Normal Feedwater Flow	Bounded by other events
Feedwater System Pipe Rupture	One Protection System Train (Failure of Fast Bus Transfer Considered)
Asymmetric Steam Generator Transient	One Protection System Train
15.3 Decrease in RCS Flow Rate	
Partial/Complete Loss of Forced Flow	One Protection System Train
Reactor Coolant Pump Seized	One Protection System Train
Rotor/Shaft Break	(Failure of Fast Bus Transfer Considered)
15.4 Reactivity and Power Distribution Anomalies	
Uncontrolled CEA Bank Withdrawal from Subcritical	One Protection System Train
Uncontrolled CEA Bank Withdrawal at Power	One Protection System Train
CEA Misoperation (Dropped Rod)	N/A
Startup of an Inactive Loop at an Incorrect Temperature	N/A
CEA Ejection	One Protection System Train
15.5 Increase in Coolant Inventory	
Inadvertent ECCS Operation at Power	N/A
CVCS Malfunction	Complete closure of letdown control valve.
15.6 Decrease in Coolant Inventory	
Inadvertent RCS Depressurization	One Protection System Train
Steam Generator Tube Rupture	N/A
Loss of Coolant Accidents	See Section 15.6

Table 15.0-32 Core Source Term

Nuclide	Core/Fuel Source (Curies)	Nuclide	Core/Fuel Source (Curies)
Kr-85	1.238E+06	Pu-239	3.823E+04
Kr-85m	1.983E+07	Pu-240	7.207E+04
Kr-87	3.767E+07	Pu-241	1.785E+07
Kr-88	5.295E+07	Am-241	2.014E+04
Rb-86	2.817E+05	Cm-242	8.940E+06
Sr-89	7.261E+07	Cm-244	3.272E+06
Sr-90	9.934E+06	I-130	6.937E+06
Sr-91	9.016E+07	Kr-83m	9.565E+06
Sr-92	9.856E+07	Xe-138	1.320E+08
Y-90	1.036E+07	Xe-131m	9.824E+05
Y-91	9.485E+07	Xe-133m	5.358E+06
Y-92	9.904E+07	Xe-135m	3.513E+07
Y-93	1.158E+08	Cs-138	1.470E+08
Zr-95	1.337E+08	Cs-134m	7.473E+06
Zr-97	1.330E+08	Rb-88	5.392E+07
Nb-95	1.352E+08	Rb-89	6.883E+07
Mo-99	1.581E+08	Sb-124	3.526E+05
Tc-99m	1.384E+08	Sb-125	2.324E+06
Ru-103	1.578E+08	Sb-126	1.787E+05
Ru-105	1.277E+08	Te-131	7.697E+07
Ru-106	9.086E+07	Te-133	9.845E+07
Rh-105	1.150E+08	Te-134	1.312E+08
Sb-127	1.163E+07	Te-125m	5.143E+05
Sb-129	3.155E+07	Te-133m	5.818E+07
Te-127	1.157E+07	Ba-141	1.304E+08
Te-127m	1.578E+06	Ba-137m	1.312E+07
Te-129	3.105E+07	Pd-109	5.544E+07
Te-129m	4.607E+06	Rh-106	9.960E+07
Te-131m	1.330E+07	Rh-103m	1.422E+08
Te-132	1.213E+08	Tc-101	1.470E+08
I-131	8.752E+07	Eu-154	2.086E+06
I-132	1.240E+08	Eu-155	1.446E+06
I-133	1.650E+08	Eu-156	4.763E+07
I-134	1.787E+08	La-143	1.198E+08
I-135	1.555E+08	Nb-97	1.342E+08

Table 15.0-32 Core Source Term (cont'd)

Nuclide	Core/Fuel Source (Curies)	Nuclide	Core/Fuel Source (Curies)
Xe-133	1.657E+08	Nb-95m	9.559E+05
Xe-135	4.394E+07	Pm-147	1.212E+07
Cs-134	3.335E+07	Pm-148	2.472E+07
Cs-136	8.190E+06	Pm-149	5.555E+07
Cs-137	1.384E+07	Pm-151	2.031E+07
Ba-139	1.439E+08	Pm-148m	2.971E+06
Ba-140	1.386E-+08	Pr-144	1.129E+08
La-140	1.448E+08	Pr-144m	1.347E+06
La-141	1.311E+08	Sm-153	6.783E+07
La-142	1.263E+08	Y-94	1.175E+08
Ce-141	1.333E+08	Y-95	1.272E+08
Ce-143	1.207E+08	Y-91m	5.234E+07
Ce-144	1.121E+08	Br-82	7.734E+05
Pr-143	1.200E+08	Br-83	9.531E+06
Nd-147	5.290E+07	Br-84	1.632E+07
Np-239	2.435E+09	Am-242	1.235E+07
Pu-238	6.206E+05	Np-238	6.601E+07
		Pu-243	1.146E+08

Table 15.0-32a Primary Coolant Source Term

Nuclide	µCuries/gm	Nuclide	µCuries/gm
Co-58	4.394E-02	Cs-136	1.543E+00
Co-60	8.256E-02	Cs-137	2.899E+00
Cr-51	1.611E-01	Ba-139	4.800E-04
Fe-55	1.818E-01	Ba-140	7.124E-03
Fe-59	2.087E-02	La-140	3.299E-03
Mn-54	2.163E-01	La-141	2.646E-04
Zn-65	4.872E-03	La-142	7.483E-05
Kr-85	4.160E+01	Ce-141	1.147E-03
Kr-85m	1.268E+00	Ce-143	6.485E-04
Kr-87	7.574E-01	Ce-144	9.815E-04
Kr-88	2.247E+00	Pr-143	1.031E-03
Rb-86	3.403E-02	Nd-147	4.302E-04
Sr-89	5.691E-03	Kr-83m	3.826E-01
Sr-90	5.459E-04	Xe-138	5.168E-01
Sr-91	1.526E-03	Xe-131m	3.022E+00
Sr-92	6.105E-04	Xe-133m	3.479E+00
Y-90	7.799E-04	Xe-135m	8.553E-01
Y-91	3.327E-02	Cs-138	9.667E-01
Y-92	7.402E-04	Cs-134m	1.179E-01
Y-93	4.706E-04	Rb-88	2.326E+00
Zr-95	1.159E-03	Rb-89	1.022E-01
Zr-97	5.170E-04	Sb-124	1.910E-03
Nb-95	1.187E-03	Sb-125	1.277E-02
Mo-99	5.111E+00	Sb-126	9.173E-04
Tc-99m	3.885E+00	Te-131	1.741E-02
Ru-103	1.359E-03	Te-134	2.280E-02
Ru-105	1.934E-04	Te-125m	2.828E-03
Ru-106	7.973E-04	Te-133m	1.326E-02
Rh-105	7.047E-04	Ba-141	1.009E-04
Sb-127	5.187E-02	Rh-103m	1.350E-03
Sb-129	2.918E-02	Nb-97	8.889E-05
Te-127	5.496E-02	Nb-95m	8.343E-06
Te-127m	8.677E-03	Pm-147	1.069E-04
Te-129	4.558E-02	Pm-148	1.866E-04

Table 15.0-32a Primary Coolant Source Term (cont'd)

Nuclide	µCuries/gm	Nuclide	µCuries/gm
Te-129m	2.486E-02	Pm-149	3.485E-04
Te-131m	4.273E-02	Pm-151	1.021E-04
Te-132	5.233E-01	Pm-148m	2.556E-05
I-131	8.425E-01	Pr-144	9.816E-04
I-132	1.689E-01	Y-94	1.528E-05
I-133	8.713E-01	Y-91m	8.872E-04
I-134	7.726E-02	Br-82	6.096E-02
I-135	3.933E-01	Br-83	1.214E-01
Xe-133	2.381E+02	Br-84	5.002E-02
Xe-135	9.235E+00		
Cs-134	6.972E+00		

Equilibrium RCS activity was adjusted to make the iodine inventory equivalent to the Technical Specification Dose Equivalent I-131 limit, and also adjusted to make the other relevant RCS isotopic inventory equivalent to the (proposed) Technical Specification limit on Dose Equivalent Xe-133, as defined in TSTF-490 (Reference 15.01-15).

The RCS activity based on core inventory and the ANSI/ANS 18.1-1999 based corrosion products were combined to produce the total equilibrium RCS activity. In addition, the equilibrium RCS activity was adjusted to make the iodine inventory equivalent to the Technical Specification Dose Equivalent I-131 limit, and also adjusted to make the other relevant RCS isotopic inventory equivalent to the (proposed) Technical Specification limit on Dose Equivalent Xe-133, as defined in TSTF-490. This combined and adjusted fission and corrosion activity RCS source term is provided in the following table.

Table 15.0-33 DBEs Analyzed With Respect to Offsite Dose Criterion

Event

A) Anticipated Operational Occurrences

1) Inadvertent Opening of a Steam Generator Relief or Safety Valve

2) Loss of Offsite Power to the Station Auxiliaries (LOAC)

B) Postulated Accidents

1) Steam System Piping Failures: Inside and Outside Containment Pre-Trip Power Excursions and Post-Trip Analysis

2) Feedwater Line Break Event

3) Single Reactor Coolant Pump Shaft Seizure/Sheared Shaft

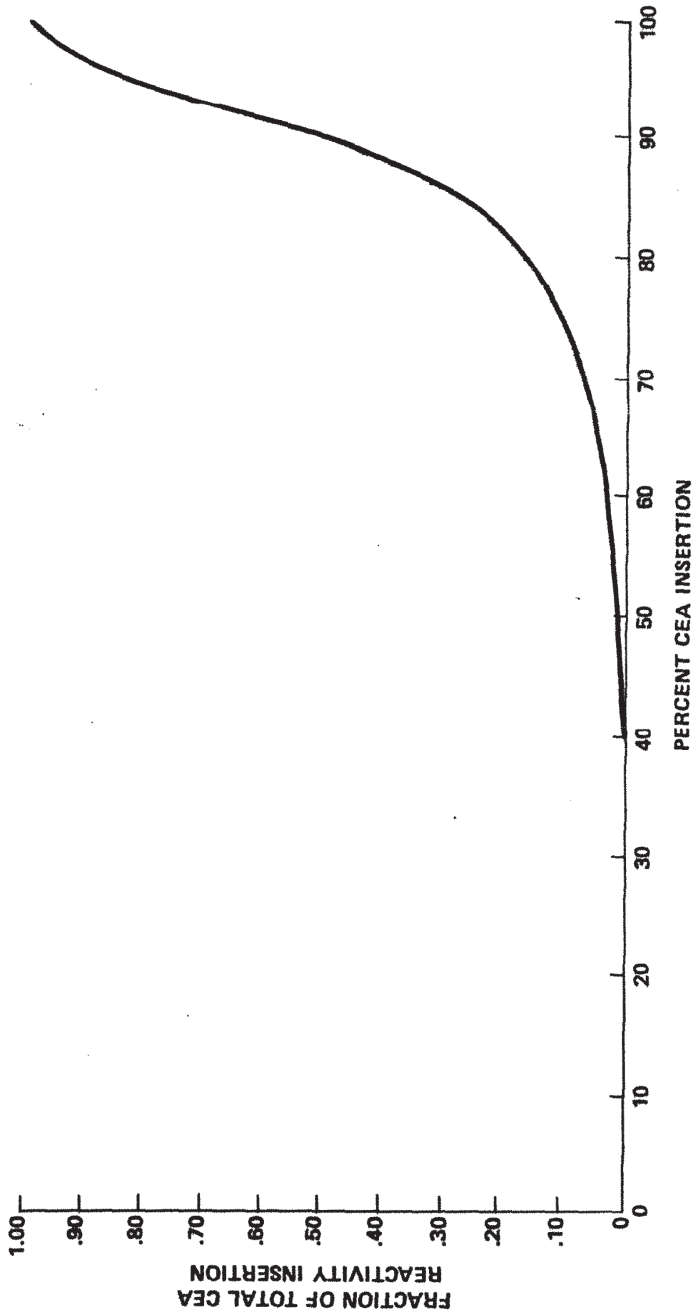
4) Small Primary Line Break Outside Containment

5) CEA Ejection

6) Steam Generator Tube Rupture

7) Loss of Coolant Accidents

8) Fuel Handling Accident

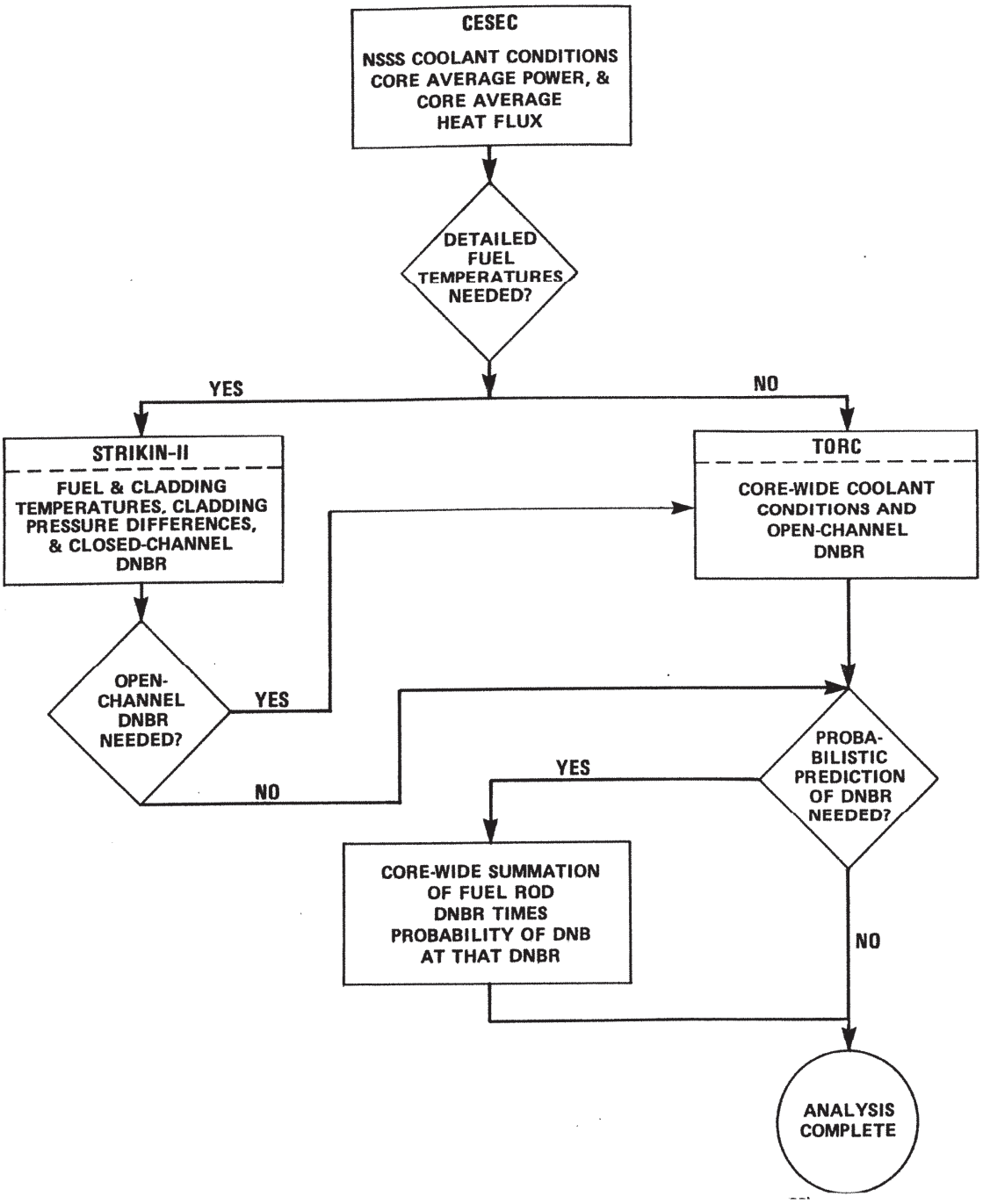


Amendment No. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

SCRAM CURVE FOR SAFETY EVALUATION

FIGURE 15.0-1

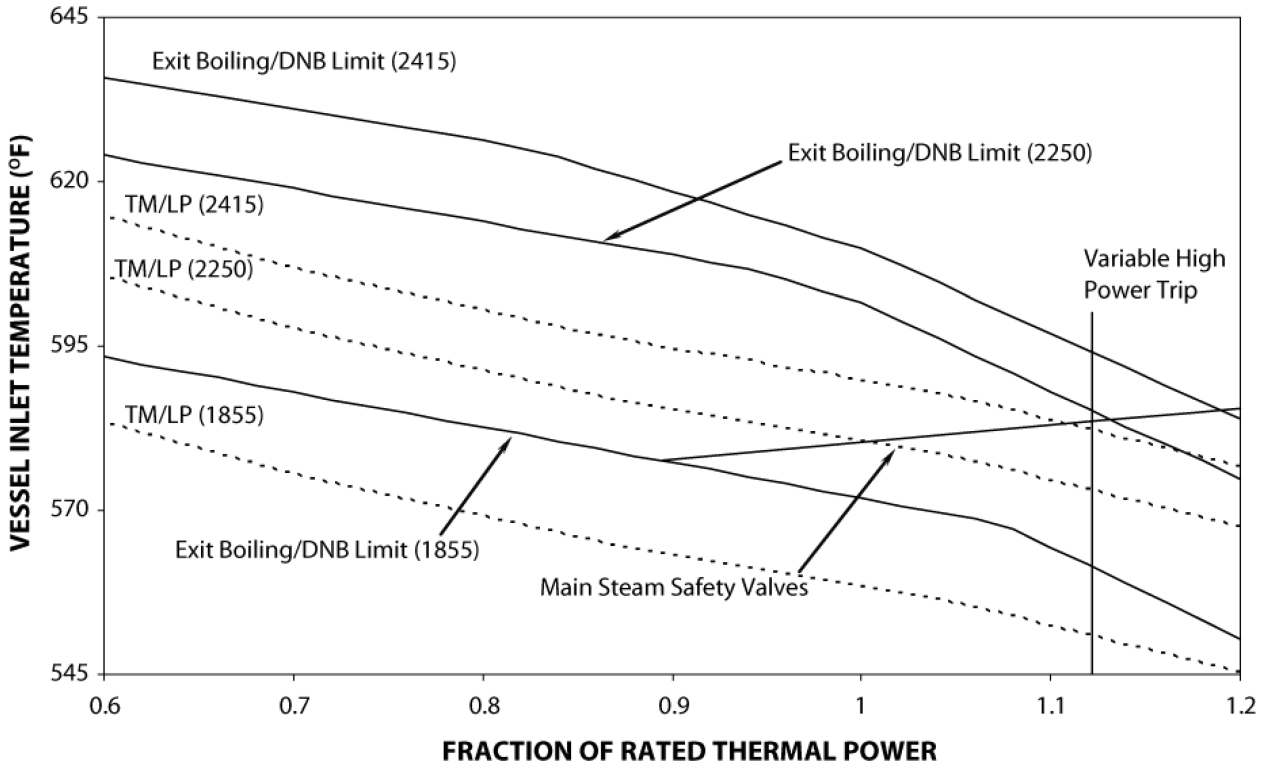


Amendment No. 1. (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

COMPUTER CODE NETWORK FOR
TRANSIENT FUEL PERFORMANCE

FIGURE 15.0-2



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.0-3 Core Thermal Limits and Protection Functions (Axial Power Distribution = 1.55 Cosine, ASI = 15%)

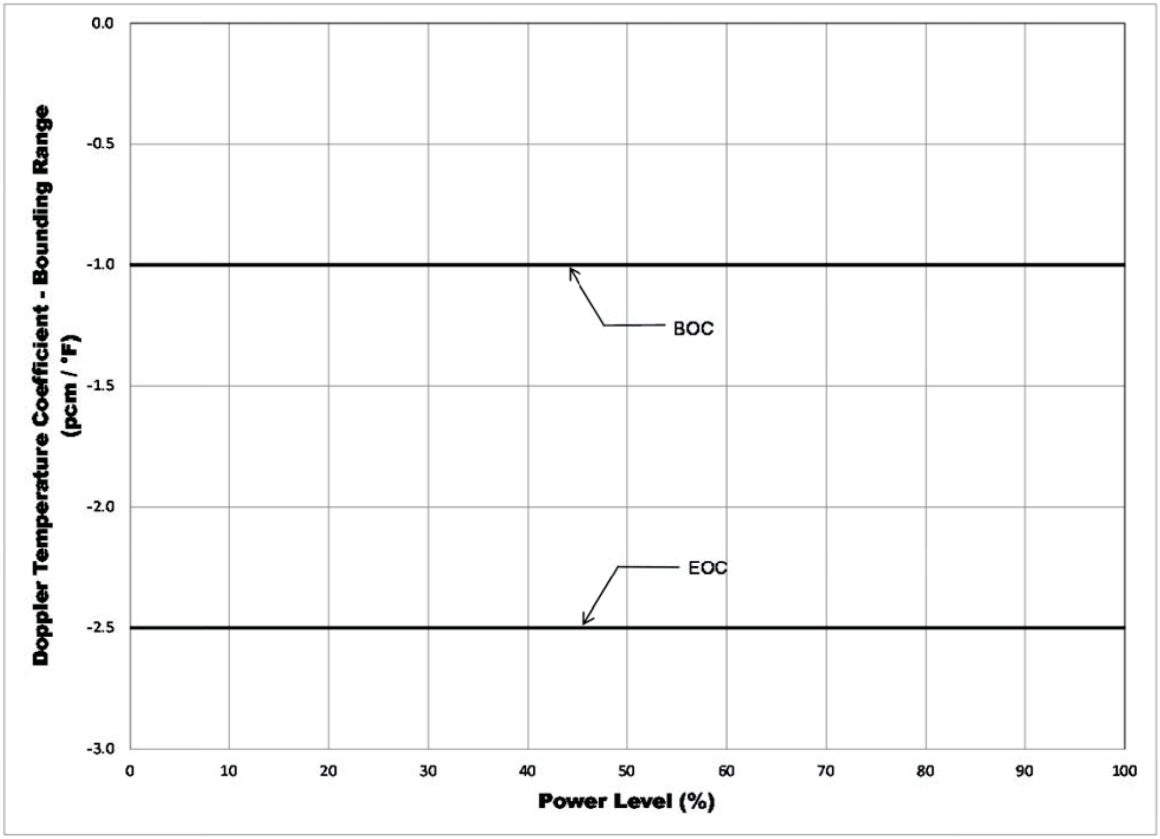


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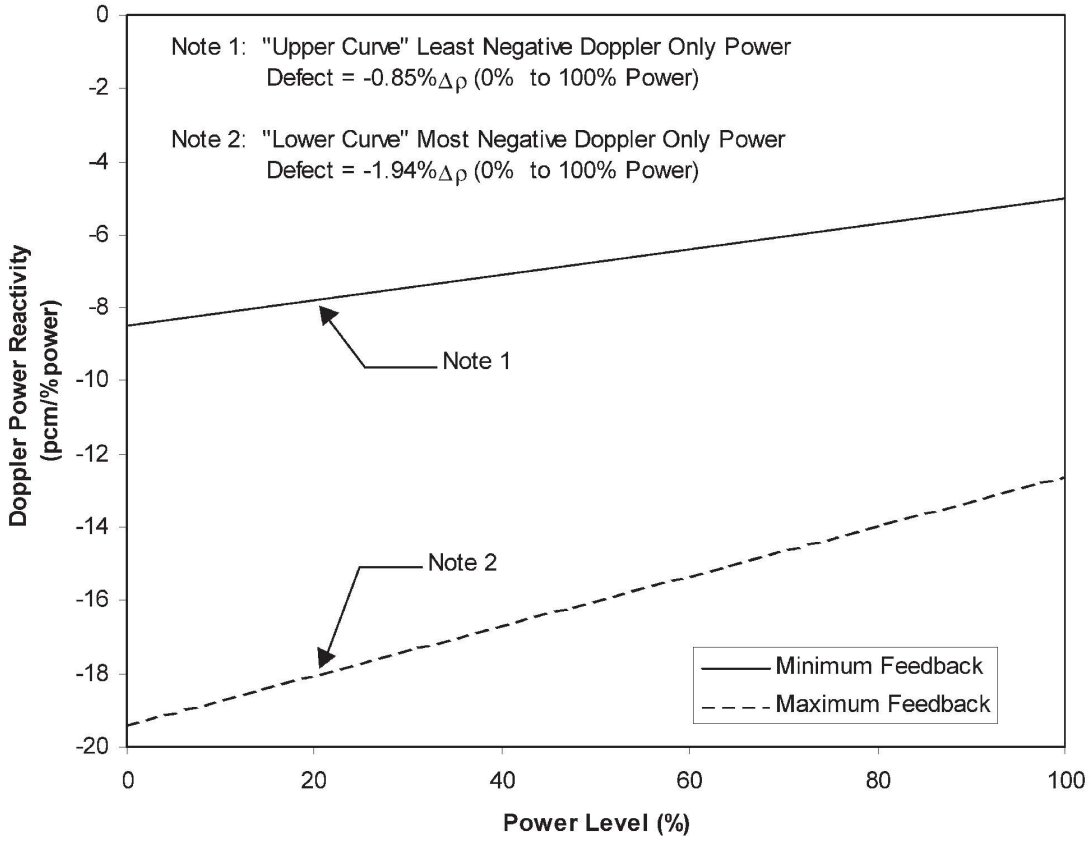
Figure 15.0-4
Doppler Temperature Coefficient Used in Accident Analyses
(AREVA)



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ST. LUCIE PLANT UNIT 2

Figure 15.0-4a
Doppler Power Coefficient Used in Accident Analyses
(Westinghouse)

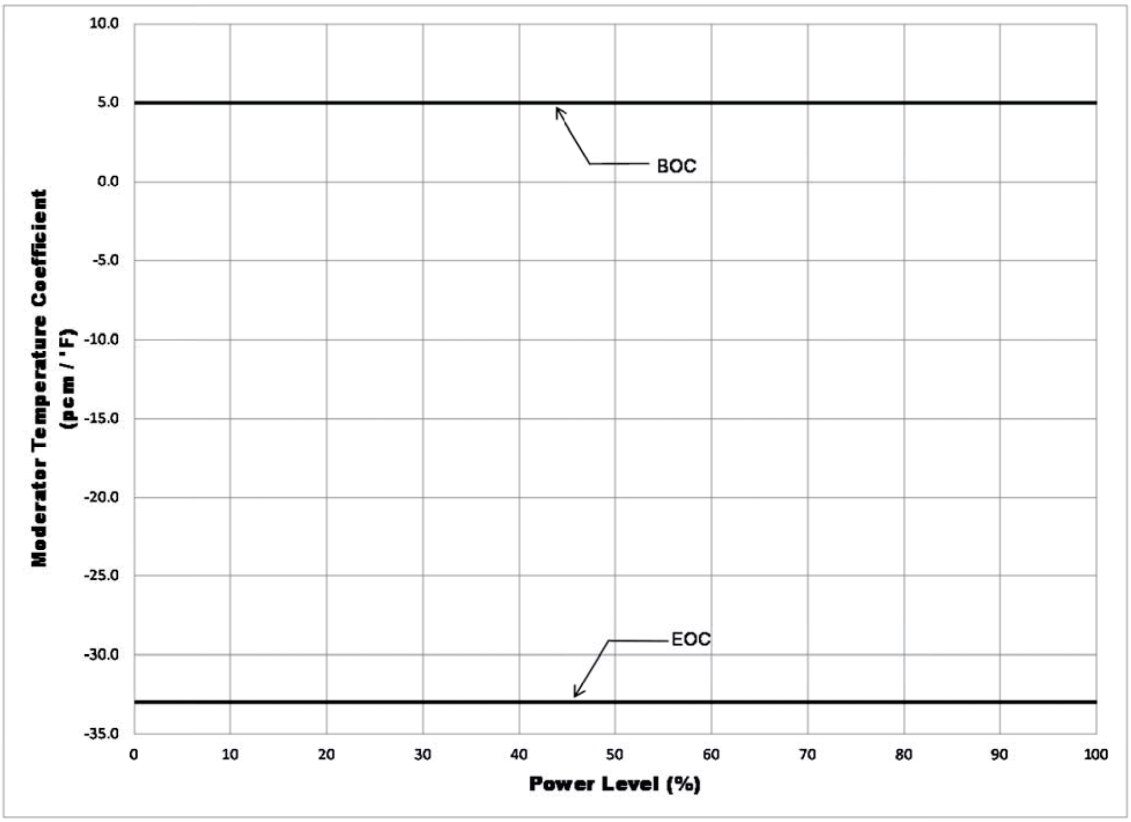

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Figure 15.0-5
Maximum Moderator Temperature Coefficient
Used in Accident Analyses
(AREVA)

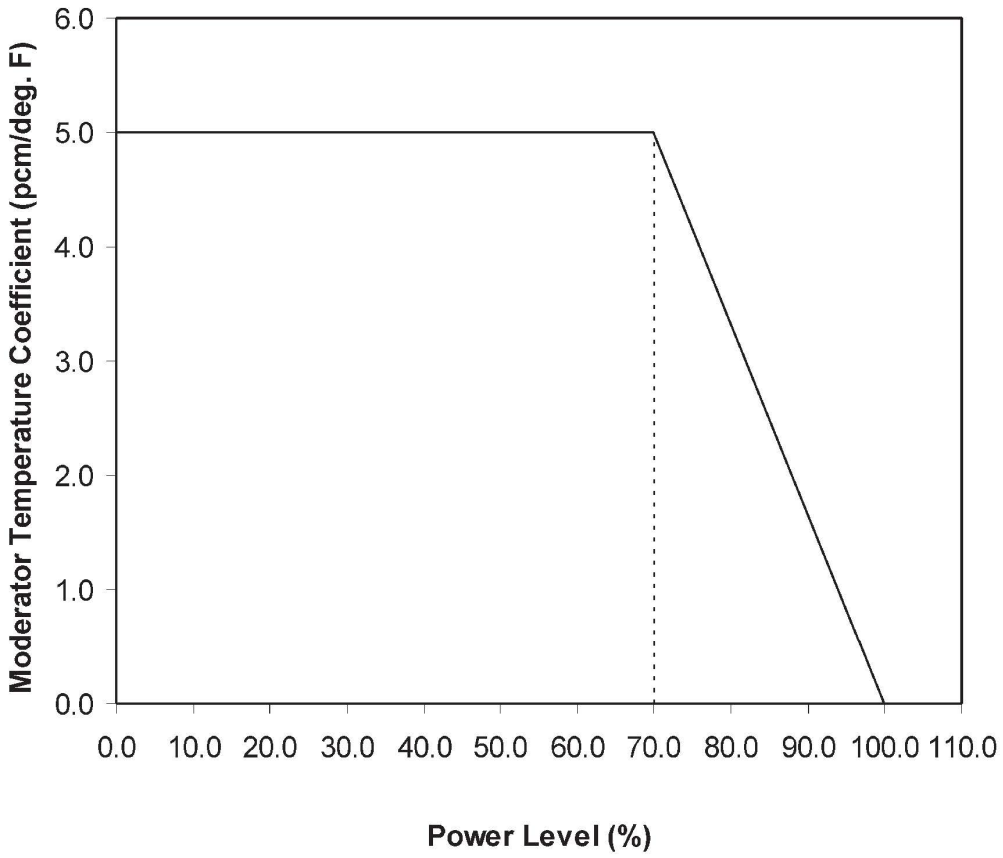

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Figure 15.0-5a
Moderator Temperature Coefficient Used in Accident Analyses
(Westinghouse)

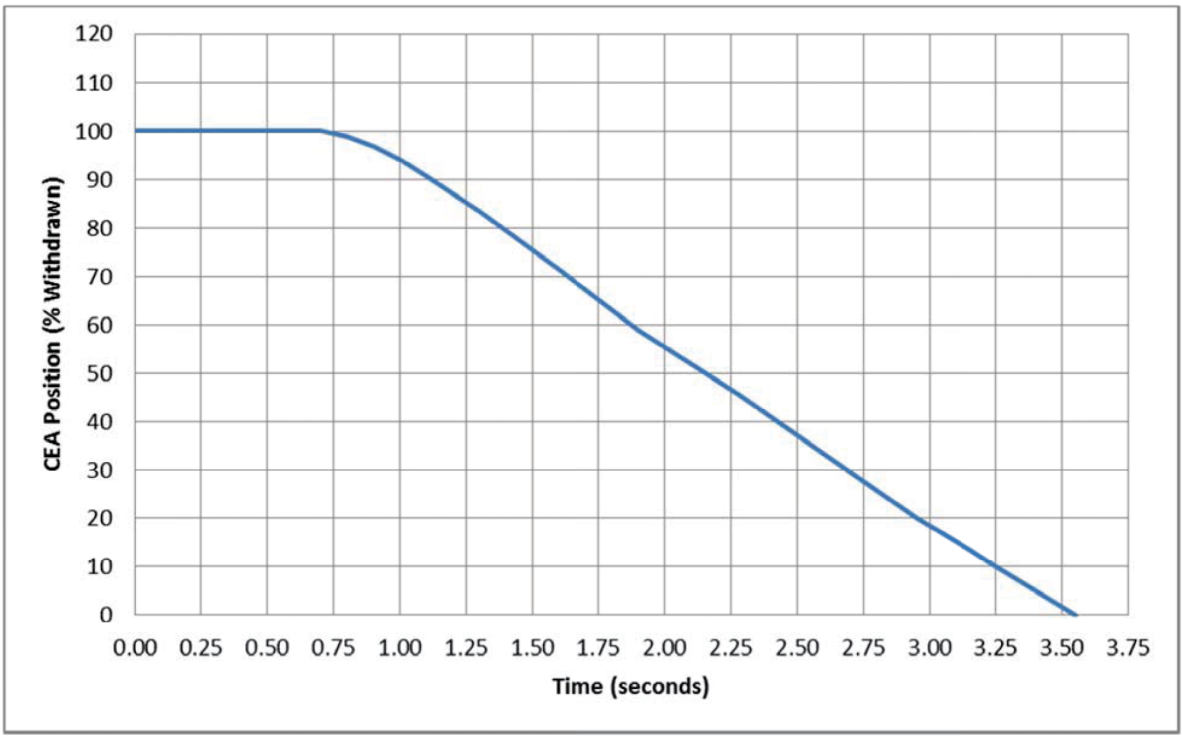

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Figure 15.0-6
CEA Insertion Position vs. Time
(AREVA)

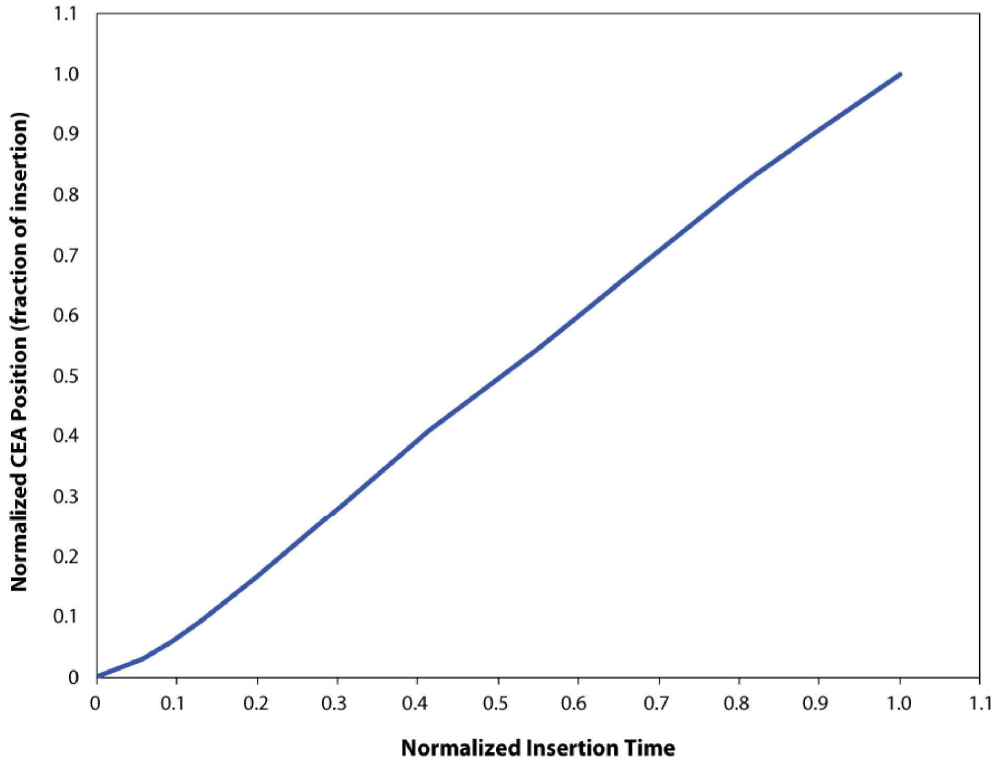

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Figure 15.0-6a
Normalized CEA Position vs. Time
(Westinghouse)

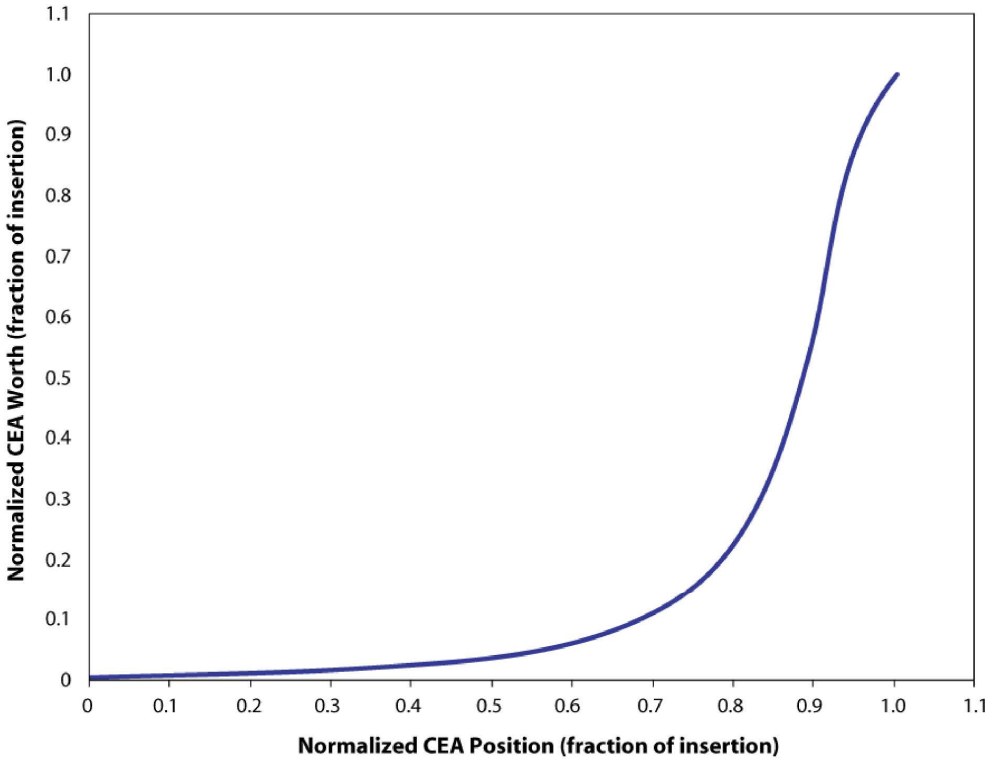

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Figure 15.0-7
Normalized CEA Worth vs. Position
(Westinghouse)

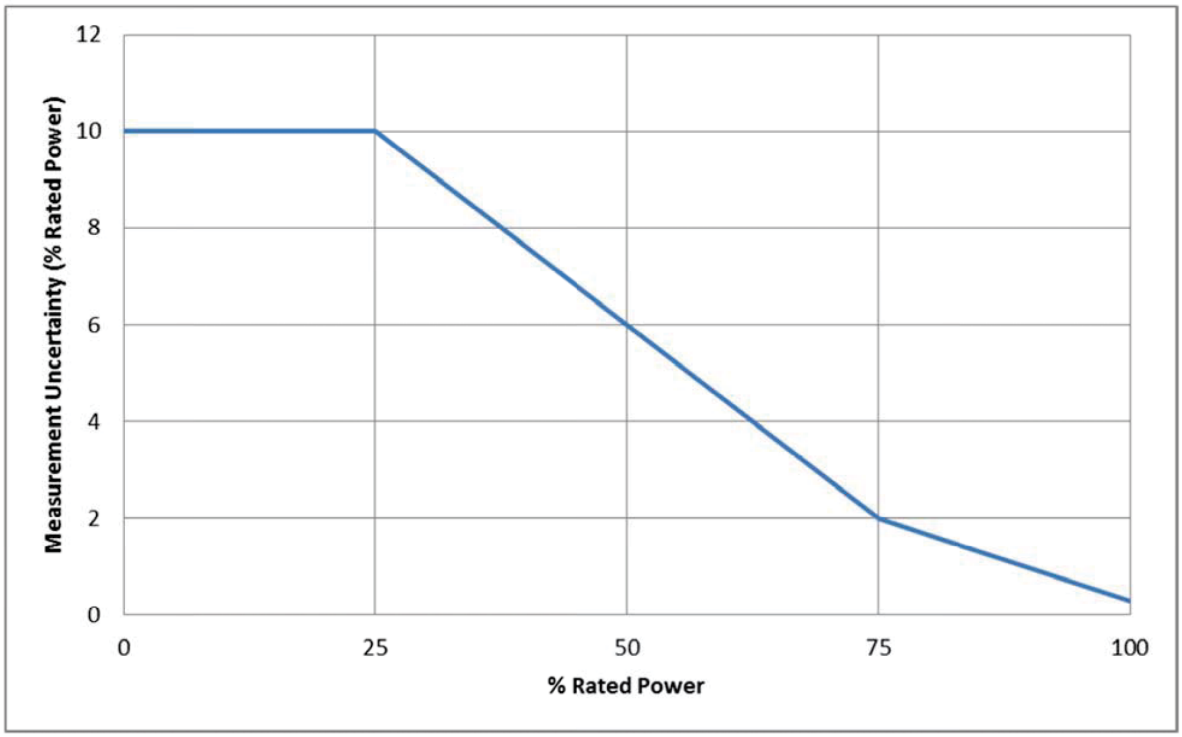

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Figure 15.0-8
Power Measurement Uncertainty Used in Accident Analysis
(AREVA)

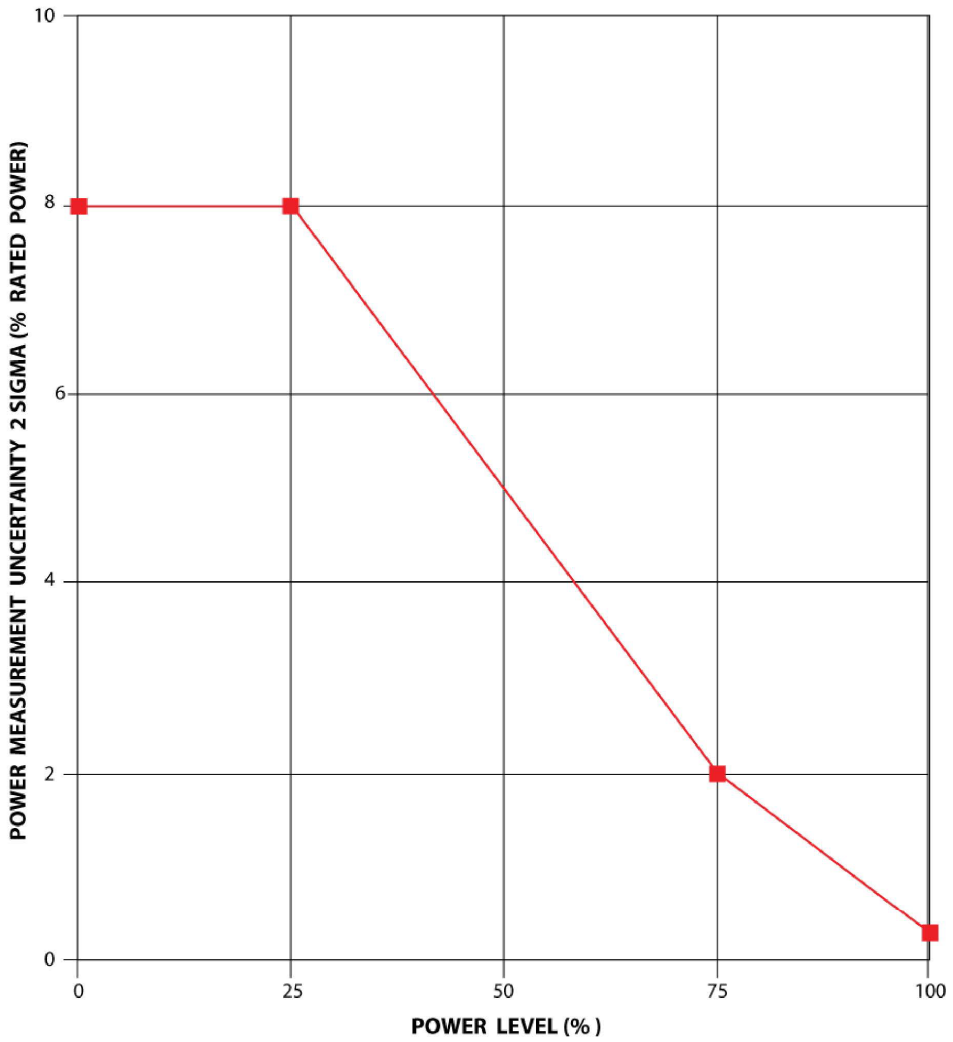

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Figure 15.0-8a
Power Measurement Uncertainty Used in Accident Analyses
(Westinghouse)

15.1 INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

A number of events have been postulated which could result in an increase in heat removal from the reactor coolant system (RCS) by the secondary system. Detailed analyses are presented for several such events, which have been identified as limiting cases.

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

a. Feedwater system malfunctions that result in a decrease in feedwater temperature (Section 15.1.1)

b. Feedwater system malfunctions that result in an increase in feedwater flow (Section 15.1.2)

c. Excessive increase in secondary steam flow (excess load) (Section 15.1.3)

d. Inadvertent opening of a steam generator relief or safety valve (Section 15.1.4)

e. Pre-Trip steam system piping failure (Section 15.1.5)

f. Post-Trip steam system piping failure (Section 15.1.6)

The above are considered to be ANS Condition II events, with the exception of steam system pipe breaks, which are considered to be ANS Condition III (minor) and Condition IV (major) events. Section 15.0.6 provides a discussion of ANS classification of plant conditions and applicable acceptance criteria.

15.1.1 FEEDWATER SYSTEM MALFUNCTIONS THAT RESULT IN A DECREASE IN FEEDWATER TEMPERATURE

A change in steam generator feedwater conditions that results in a decrease in feedwater temperature could result in excessive heat removal from the plant primary coolant system. Such changes in feedwater temperature are a result of a failure of a feedwater control valve, feedwater bypass valve, failure in the feedwater control system, operator error or accidental starting of the auxiliary feedwater system.

The occurrence of these failures that result in an excessive heat removal from the plant primary coolant system cause the primary-side temperature and pressure to decrease significantly. The existence of a negative moderator and fuel temperature reactivity coefficients can cause core reactivity to rise, as the primary-side temperature decreases. In the absence of the reactor protection system (RPS) reactor trip or other protective action, this increase in core power, coupled with the decrease in primary-side pressure, can challenge the core thermal limits. Therefore, the Excessive Heat Removal Due to Feedwater System Malfunctions Event is analyzed to ensure that the Departure from Nucleate Boiling (DNB) is not violated.

15.1.1.1 Accident Description

Another example of excessive heat removal from the reactor coolant system is the transient associated with loss of high pressure feedwater heaters. In the event of a loss of high pressure feedwater heaters, there could be an immediate reduction in feedwater temperature to the

steam generators. At power, the increased sub-cooling will create a greater load demand on the reactor coolant system due to the increased heat transfer in the steam generator.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient. However, the rate of energy change is reduced as load and feedwater flow decrease, so that the transient is less severe than the full power case.

The net effect on the RCS due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow. If the increase in reactor power is large enough, the primary RPS trip functions (e.g., variable power level, VHPT) will prevent any power increase that can lead to a departure from nucleate boiling ratio (DNBR) less than the safety analysis limit value.

15.1.1.2 Method of Analysis

The feedwater system malfunction transient is analyzed using the RETRAN code. The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code that has been reviewed and approved by the USNRC for pressurized water reactor licensing applications (References 15.1-1 and 15.1-4). The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models and two-phase natural convection heat transfer correlations. The results from the RETRAN computer code are used to determine if the DNB safety analysis limits for the excessive heat removal due to feedwater malfunction event are met.

The feedwater malfunction analysis resulting in a feedwater temperature reduction is performed to demonstrate that the DNB design basis is satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR using the same methods described in the feedwater flow increase analysis (see Section 15.1.2) with the following assumptions.

1. At full power conditions the reduced feedwater enthalpy is assumed to be 313.5 Btu/lbm which corresponds to a reduced feedwater temperature of 341ºF.

2. The excessive feedwater temperature reduction assumes the nominal full power feedwater flow is maintained to both steam generators.

Protection against undesirable conditions is similar to that described for the increased feedwater flow event (see Section 15.1.2).

AREVA Analysis

For the fuel transition, detailed analyses were performed with the approved non-LOCA methodology given in Reference 15.1-7, as supplemented in Section 2.7 of Reference 15.1-8. For this event, the S RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of minimum DNBR (MDNBR). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.1-9), which was used to calculate the MDNBR using the High Thermal Performance (HTP) critical heat flux (CHF) correlation (Reference 15.1-10). EC287528

Key input parameters and their values used in the analysis of this event were consistent with, or conservative relative to, the approved Reference 15.1-7 methodology, as supplemented in Section 2.7 of Reference 15.1-8. See Table 15.0-27 for key input parameter values.

- Initial Conditions – The event was assumed to initiate from full-power conditions with a maximum core inlet temperature and Technical Specification (TS) minimum RCS flow rate. This set of conditions minimizes the initial margin to DNB.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. The moderator reactivity feedback was analyzed using the most-negative analytical limit. The negative MTC leads to higher power levels during the event, as a result of the primary system cooldown. Doppler reactivity was biased to minimize the effects of negative feedback from increasing fuel temperatures.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil release delay time.

  The overcooling of the primary system results in decalibration of the ex-core nuclear detectors and delays the RPS nuclear instrumentation (NI) power signal in reaching the VHP trip setpoint. In addition, the resistance temperature detector (RTD) lag times for the hot legs and cold legs were conservatively biased to minimize the RPS thermal power signal and further delay the VHP trip. EC287528

- Feedwater Systems – The main feedwater (MFW) temperature was reduced to 326°F, and the MFW control valves were assumed to maintain the nominal full powervolumetric flow rate to both steam generators during the event.

- Main Steam System – The turbine control valve (TCV) was assumed to be operating in the automatic control mode, to maintain constant steam flow during the event. The TCV was assumed to be capable of passing 120% of the nominal steam flow at its valve-wide-open position. Maximizing the capacity of the TCV worsens the cooldown of the RCS and the moderator-reactivity-driven power response.

- Gap Conductance – The fuel-to-cladding gap conductance was set to a conservative EOC value, to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback. The gap conductance accounts for fuel thermal conductivity degradation (TCD).

- Steam Generator Tube Plugging – No SGTP was assumed, so as to maximize the primary-to-secondary-side heat transfer, which exacerbates the reactivity insertion due to moderator feedback.

- Single Failure – There is no single failure that will adversely affect the consequences, because the systems designed to mitigate this event (namely, the RPS) are redundant.

15.1.1.3 Results

The loss of high pressure feedwater heaters causes a reduction in feedwater temperature which increases the thermal load on the primary system. The excessive feedwater flow increase case generates a more limiting condition than the reduction in feedwater temperature case performed

at full power initial conditions. The power increases until reactor trip is actuated when the variable high power trip setpoint is reached. The peak core heat flux and minimum DNB condition is reached shortly after the CEAs begin to drop into the core. The consequences of the event are mitigated prior to reaching a high steam generator water level condition in either steam generator. The limiting full power feedwater temperature reduced conditions were analyzed and it was confirmed that the calculated minimum DNBR is above the DNBR safety analysis limit. Therefore, the applicable DNBR acceptance criterion is met.

Table 15.1.1-1 shows the calculated sequence of events for the full power feedwater malfunction transient case resulting in a reduction in feedwater temperature. Figures 15.1.1-1 through 15.1.1-7 show transient responses for various system parameters during a feedwater system malfunction causing a feedwater temperature reduction from full power conditions. No fuel or cladding damage is predicted for this accident. All applicable acceptance criteria are satisfied.

AREVA Analysis

The sequence of events is given in Table 15.1.1-2, and the results are given in Table 15.1.1-3. State-points for the DNB calculations were chosen at, and near, the time of peak heat flux. The limiting MDNBR was calculated to be above the 95/95 CHF correlation limit. The peak LHR was calculated to be less than the fuel centerline melt limit. EC287528

The transient response is shown in Figure 15.1.1-8 through Figure 15.1.1-14. Figure 15.1.1-8 shows the reactor power as a function of time, and Figure 15.1.1-9 shows the core power based on rod surface heat flux. Figure 15.1.1-10 through Figure 15.1.1-14 show the pressurizer pressure, RCS loop temperatures, steam generator pressures, steam and feedwater flow rates, and reactivity feedback, respectively.

15.1.1.4 Conclusions

The results of the analysis show that the VHPT or TM/LP reactor protection system signal provides adequate protection against the feedwater malfunction transient. No fuel or clad damage is predicted for this accident. All acceptance criteria are satisfied.

15.1.2 FEEDWATER SYSTEM MALFUNCTIONS THAT RESULT IN AN INCREASE IN FEEDWATER FLOW

A change in steam generator feedwater conditions that results in an increase in feedwater flow could result in excessive heat removal from the plant primary coolant system. Such changes in feedwater flow are a result of a failure of a feedwater control valve, feedwater bypass valve, failure in the feedwater control system, operator error or accidental starting of the auxiliary feedwater system.

The occurrence of these failures that result in an excessive heat removal from the plant primary coolant system cause the primary-side temperature and pressure to decrease significantly. The existence of a negative moderator and fuel temperature reactivity coefficients can cause core reactivity to rise, as the primary-side temperature decreases. In the absence of the reactor protection system (RPS) reactor trip or other protective action, this increase in core power, coupled with the decrease in primary-side pressure, can challenge the core thermal limits. Therefore, the Excessive Heat Removal Due to Feedwater System Malfunctions Event is analyzed to ensure that the DNB is not violated.

15.1.2.1 Accident Description

An example of excessive heat removal from the reactor coolant system is the accidental opening of the feedwater regulating valves resulting in an increase of feedwater flow to both steam generators, causing excessive heat removal from the reactor coolant system. At power, excess feedwater flow causes a greater load demand on the primary side due to increased sub-cooling in the steam generator. With the plant at zero power conditions, the addition of relatively cold feedwater may cause a decrease in primary-side temperature, and, therefore, a reactivity insertion due to the effects of the negative moderator temperature coefficient. The resultant decrease in the average temperature of the core causes an increase in core power due to moderator and control system feedback. This transient is attenuated by the thermal capacity of the primary and secondary sides. If the increase in reactor power is large enough, the primary RPS trip functions (e.g., high neutron flux, VHPT) will prevent any power increase that can lead to a DNBR less than the safety analysis limit value. The RPS trip functions may not actuate if the increase in power is not large enough.

15.1.2.2 Method of Analysis

The feedwater malfunction analysis causing an increase in feedwater flow is performed to demonstrate that the DNB design basis is satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the DNBR safety analysis limit.

The feedwater system malfunction transient is analyzed using the RETRAN code. The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code, that has been reviewed and approved by the USNRC for pressurized water reactor licensing applications (References 15.1-1 and 15.1-4). The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models and two-phase natural convection heat transfer correlations. The results from the RETRAN computer code are used to determine if the DNB safety analysis limits for the excessive heat removal due to feedwater malfunction event are met.

Feedwater system failures, including the accidental opening of the feedwater control valves, have the potential of allowing increased feedwater flow to each steam generator that will result in excessive heat removal from the reactor coolant system. Therefore it is assumed that the feedwater control valves fail in the full open position allowing the maximum feedwater flow to both steam generators. Also addressed is the initiation of a feedwater malfunction event from a hot zero power condition.

The following assumptions are made for the analysis of the feedwater malfunction event involving the accidental opening of the feedwater control valves:

1. The plant is operating at full power conditions (no load conditions for the hot zero power case) with the initial reactor power, pressure and RCS average temperatures assumed to be at the nominal values.

2. Uncertainties in initial conditions are included in the DNBR limit calculated using the Revised Thermal Design Procedure (RTDP) methodology (Reference 15.1-2), where applicable (full power cases).

3. The feedwater temperature of 391ºF for the full power cases is conservative with respect to normal plant conditions. The feedwater enthalpy assumed at no-load conditions corresponds to a feedwater temperature of 250ºF.

4. The excessive feedwater flow event assumes accidental opening of the feedwater control valves with the reactor at full power and zero power while modeling a post reactor trip conditions with minimum shutdown margin. The feedwater flow malfunction results in a step increase to 120% of the nominal full power feedwater flow to both steam generators.

5. Maximum (end of life) reactivity feedback conditions with a minimum Doppler-only power defect is conservatively assumed.

6. The heat capacity of the Reactor Coolant System metal and steam generator shell are ignored, thereby maximizing the temperature reduction of the RCS coolant.

7. The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high water level signal or operator action.

The automatic rod control system is not modeled as it is disabled at the plant. The reactor protection system functions to trip the reactor on the appropriate signal. No single active failure will prevent the reactor protection system from functioning properly.

Protection against undesirable conditions is provided by steam generator water level alarms with automatic or manual control actions to reduce feedwater flow, and in extreme cases by reactor trips due to high power (VHPT), low pressurizer pressure, thermal margin/low pressure (TM/LP), or low steam generator pressure.

AREVA Analyses

For the fuel transition, detailed analyses were performed with the approved non-LOCA methodology given in Reference 15.1-7, as supplemented in Section 2.7 of Reference 15.1-8. For this event, the S RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.1-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.1-10).

EC287528

This event was analyzed from both full-power and HZP conditions. For the HZP analysis, a hot spot fuel centerline temperature model was employed to evaluate margin to fuel melt.

Key input parameters and their values used in the analyses of this event were consistent with, or conservative relative to, the approved Reference 15.1-7 methodology, as supplemented in Section 2.7 of Reference 15.1-8. See Table 15.0-27 for key input parameter values.

- Initial Conditions – The event was assumed to initiate with a maximum core inlet temperature and TS minimum RCS flow rate. This set of conditions minimizes the initial margin to DNB.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. The moderator reactivity feedback was analyzed using the most-negative analytical limit. The negative MTC leads to higher power levels during the event, as a result of the primary system cooldown. Doppler reactivity was biased to minimize the effects of negative feedback from increasing fuel temperatures.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil release delay time.

- The overcooling of the primary system results in decalibration of the ex-core nuclear detectors and delays the RPS NI power signal in reaching the VHP trip setpoint. In addition, the RTD lag times for the hot legs and cold legs were conservatively biased to minimize the RPS thermal power signal and further delay the VHP trip.

- Feedwater Systems – The MFW flow was increased to 130% of the nominal full power volumetric flow rate for the full-power case and delivered to both steam generators during the event. The MFW temperature was reduced to 340°F in conjunction with the increase in MFW flow, to account for the lower MFW heater residency time, and thus decreased MFW heating, that may be associated with the increased MFW flow through the heaters. For the HZP case, the MFW flow was increased to 120% of the nominal full power volumetric flow rate and delivered to both steam generators during the event, at a constant temperature of 235°F. EC287528

- Main Steam System – The TCV was assumed to be operating in the automatic control mode, to maintain constant steam flow, during the full-power event. The TCV was assumed to be capable of passing 120% of the nominal steam flow at its valve-wide-open position. Maximizing the capacity of the TCV worsens the cooldown of the RCS and the moderator-reactivity-driven power response. At HZP, the TCV was assumed to be in the manual mode.

- Gap Conductance – The fuel-to-cladding gap conductance was set to a conservative EOC value, to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback. The gap conductance accounts for the effects of TCD.

- Steam Generator Tube Plugging – No SGTP was assumed, so as to maximize the primary-to-secondary-side heat transfer, which exacerbates the reactivity insertion due to moderator feedback.

- Single Failure – There is no single failure that will adversely affect the consequences, because the systems designed to mitigate this event (namely, the RPS) are redundant.

15.1.2.3 Results

The results of the analyses demonstrate that the hot full power case meets the applicable DNBR acceptance criterion.

The limiting case is the excessive feedwater flow from a full power initial condition. This case gives the largest reactivity feedback and results in the greatest power increase. The power increases until reactor trip is actuated when the variable high power trip setpoint is reached. The

peak core heat flux and minimum DNB condition is reached shortly after the CEAs begin to fall. The consequences of the event are mitigated prior to reaching a high steam generator water level condition in either steam generator, however feedwater will be terminated after reaching the high-high steam generator water level setpoint. The limiting full power feedwater flow increase conditions were analyzed and it was confirmed that the calculated minimum DNBR is above the safety analysis DNBR limit. Therefore, the applicable DNBR acceptance criterion is met.

The excessive feedwater flow from a zero power condition models a hot zero power (HZP) post-trip condition (i.e., HZP stuck rod coefficients, minimum shutdown margin) with maximum reactivity feedback conditions (end of life). The effects of an increased feedwater flow and combined reactivity feedback effect at post-trip conditions is not sufficient to offset the impact of the minimum shutdown worth of the CEAs. As a result, there is no return to power, and therefore, no challenge to the minimum DNBR criterion.

Table 15.1.2-1 shows the calculated sequence of events for the full power feedwater malfunction transient case resulting in an increase in feedwater flow. Figures 15.1.2-1 through 15.1.2-7 show transient responses for various system parameters during a feedwater system malfunction causing a feedwater flow increase initiated from full power conditions. The increase in feedwater flow at zero power conditions does not result in any return to power condition. No fuel or cladding damage is predicted for this accident. All applicable acceptance criteria are satisfied.

AREVA Analyses

The sequence of events for the full-power analysis is given in Table 15.1.2-2, and the results are given in Table 15.1.2-3. State-points for the DNB calculations were chosen at, and near, the time of peak heat flux. The limiting MDNBR was calculated to be above the 95/95 CHF correlation limit. The peak LHR was calculated to be less than the fuel centerline melt limit.

The full-power transient response is shown in Figure 15.1.2-8 through Figure 15.1.2-14. Figure 15.1.2-8 shows the reactor power as a function of time, and Figure 15.1.2-9 shows the core power based on rod surface heat flux. Figure 15.1.2-10 through Figure 15.1.2-14 show the pressurizer pressure, RCS loop temperatures, steam generator pressures, steam and feedwater flow rates, and reactivity feedback, respectively. EC287528

The sequence of events for the HZP analysis is given in Table 15.1.2-2, and the results are given in Table 15.1.2-3. The peak fuel centerline temperature (CLT) was less than the melt temperature for any fuel composition in the core, and the limiting MDNBR was calculated to be above the 95/95 CHF correlation limit. There was no post-trip return to power and, therefore, no challenge to the minimum DNBR criterion.

The HZP transient response is shown in Figure 15.1.2-15 through Figure 15.1.2-22. Figure 15.1.2-15 shows the reactor power as a function of time, and Figure 15.1.2-16 shows the core power based on rod surface heat flux. Figure 15.1.2-17 through Figure 15.1.2-22 show the pressurizer pressure, RCS loop temperatures, steam generator pressures, steam and feedwater flow rates, reactivity feedback, and peak fuel centerline temperature, respectively.

15.1.2.4 Conclusions

The results of the analysis show that the VHPT or TM/LP reactor protection system signal provides adequate protection against the feedwater malfunction transient. No fuel or clad damage is predicted for this accident. All acceptance criteria are satisfied.

EC287528

15.1.3 EXCESSIVE INCREASE IN SECONDARY STEAM FLOW (EXCESS LOAD)

15.1.3.1 Accident Description

An excessive increase in main steam flow event is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. For this accident the steam flow for EPU is assumed to increase by up to 58% of the initial value. This accident could result from one of the following:

1. An administrative violation such as excess loading by the operator.
2. Equipment malfunction in the steam dump control
3. Turbine throttle valve control malfunction.

The increased steam flow draws more heat from the primary side. This reduces the temperature of the water in the RCS. In the presence of a negative moderator temperature coefficient, the RCS temperature reduction can result in a nuclear power increase. The reduced coolant temperature also results in a reduction in the pressurizer water volume, due to the increased density of the cooler RCS water, and a reduction in the pressurizer pressure. Given an increase in core power and the reduction in the RCS pressure, the possible consequence of this accident (assuming no protective functions) is DNB with subsequent fuel damage.

15.1.3.2 Method of Analysis (AREVA)

EC287528

The analyses were performed with the approved non-LOCA methodology given in Reference 15.1-7, as supplemented in Section 2.7 of Reference 15.1-8. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.1-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.1-10).

A spectrum of calculations, varying the MTC from -10 pcm/°F to the most-negative analytical limit of -33 pcm/°F, was performed at EOC full-power conditions, TS maximum core inlet temperature, and TS minimum RCS flow rate. The analyses simulated an inadvertent and instantaneous full opening of the Steam Bypass Control System (SBCS) valves, while holding the TCV at the full-power position. This produced the maximum reactor coolant system cooling for cases initiated from full power and, thus, the minimum margins to the DNB and fuel centerline melt (FCM) limits.

Also, a single HZP case was analyzed, using the most-negative moderator temperature reactivity feedback. The analysis simulated an inadvertent and instantaneous full opening of the

TCV, which maximized the cooling of the reactor coolant system for cases initiated from HZP, challenging the DNB and FCM SAFDLs.

The key input parameters and their values used in the analyses of this event were consistent with, or conservative relative to, the approved Reference 15.1-7 methodology, as supplemented in Section 2.7 of Reference 15.1-8. See Table 15.0-27 for key input parameter values.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology.
- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil release delay time. EC287528
- Fuel Rod Gap Conductance – The fuel-to-cladding gap conductance was set to a conservative EOC value, to be consistent with the time-in-cycle for the reactivity coefficients. The gap conductance accounts for the effects of TCD.
- Steam Generator Tube Plugging – The analyses conservatively assumed 0% SGTP.
- Auxiliary Feedwater – In the HZP case, a maximum AFW flow rate and a minimum AFW temperature were modeled, to maximize the cooldown.
- Reactor Coolant Pumps – In the HZP case, the reactor coolant pumps (RCPs) were assumed to be tripped at the time of the safety injection actuation signal (SIAS), in order to delay the time for borated fluid from the High Pressure Safety Injection (HPSI) pumps to reach the core.

15.1.3.3 Results (AREVA)

The sequence of events for the HZP case is shown in Table 15.1.3-1. The MDNBR and peak fuel CLT results are given in Table 15.1.3-2. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation, and the maximum fuel centerline temperature was less than the melting temperature for any fuel composition in the core. The system responses are shown in Figure 15.1.3-1 through Figure 15.1.3-9.

The sequence of events for the limiting full-power case is shown in Table 15.1.3-1. The MDNBR and peak LHR results are given in Table 15.1.3-2. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation, and the peak LHR was less than the melt limit for any fuel composition in the core. The system responses are shown in Figure 15.1.3-10 through Figure 15.1.3-16.

15.1.3.4 Conclusions

Westinghouse

Based on the fact that the pre-trip steamline break (with failure of a fast bus transfer) analysis meets the acceptance criteria associated with an ANS Condition II event, the excessive increase in main steam flow event is bounded. Therefore, an explicit analysis of the excessive increase in main steam flow event is not required.

The radiological consequences due to steam releases from the secondary system would be less severe than the consequences of the feedwater line break accident (see Section 15.2.8). While feedwater line break is not an AOO, it is analyzed to the same radiological dose criteria as an increased main steam flow event. EC287528

AREVA

The results of the analyses show that the VHP or TM/LP reactor protection system trip provides adequate protection against the excessive increase in main steam flow transient. No fuel or cladding damage is predicted for this accident. All applicable acceptance criteria are satisfied.

15.1.4 INADVERTENT OPENING OF A STEAM GENERATOR RELIEF OR SAFETY VALVE

15.1.4.1 Accident Description

The inadvertent opening of a main steam relief or safety valve results in a transient similar to a steamline break event. Upon the inadvertent opening of a main steam relief or safety valve, steam flow would increase causing a mismatch between the reactor core power and the steam generator load demand. The increased steam flow draws more heat from the primary side. This reduces the temperature of the water in the RCS. In the presence of a negative moderator temperature coefficient, the RCS temperature reduction can result in a nuclear power increase if analyzed from an at power condition. If analyzed from sub-critical conditions, the assumption of a stuck CEA in conjunction with a negative moderator temperature coefficient could result in a reactivity transient that overcomes the shutdown margin and results in a subsequent return to power. In both cases, the reduced coolant temperature results in a reduction in the RCS pressure due to the increase in coolant density. Given an increase in core power and the reduction in the RCS pressure, the possible consequence of this accident is departure from nucleate boiling (DNB) with subsequent fuel damage.

15.1.4.2 Conclusions

Westinghouse EC287528

Based on the fact that both the pre-trip steamline break (with failure of a fast bus transfer) and post-trip steamline break analyses (Sections 15.1.5 and 15.1.6) meet the acceptance criteria associated with an ANS Condition II event, the inadvertent opening of a main steam relief or safety valve event is bounded. Therefore, an explicit analysis of the inadvertent opening of a main steam relief or safety valve event is not performed. The radiological consequences of this event are enveloped by those presented in Section 15.2.8 for feedwater line break analysis which is analyzed to the same radiological dose criteria.

AREVA

The inadvertent opening of a steam generator relief of safety valve is bounded at HFP by the Excess Load event (UFSAR 15.1.3), which does experience a reactor trip and does challenge the SAFDLs. At HZP, it is bounded by post-trip steam system piping failure (UFSAR 15.1.6) as long as that event meets AAO criteria. EC287528

15.1.5 PRE-TRIP STEAM SYSTEM PIPING FAILURE

15.1.5.1 Accident Description

A rupture in the main steam system piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the RCS via the steam generators. This results in a reduction in RCS temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-cycle life conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow. Depending on the break size, a reactor trip may occur due to overpower conditions or as a result of low steam generator pressure.

Westinghouse

The steam system piping failure accident analysis described in Section 15.1.6 is performed assuming a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod in the fully withdrawn position, out of the core. That condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped manually or by the reactor protection system following a steam line break from an at-power condition. For an at-power break, the analysis of Section 15.1.6 represents the limiting condition with respect to core protection for the time period following reactor trip.

AREVA

The steam system piping failure accident analysis described in Section 15.1.6 evaluates the limiting condition with respect to core protection for the time period following reactor trip. EC287528

The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition and to demonstrate that core protection is maintained prior to and immediately following reactor trip. Various cases are analyzed, including inside and outside containment breaks with a Failure of the Fast Bus Transfer (FFBT), and an inside containment break with a Loss of Offsite Power (LOOP) at Break Initiation.

Depending on the size of the break, this event is classified as either an ANS Condition III (infrequent fault) or Condition IV (limiting fault), as defined in Section 15.0.6. The acceptance criteria for this event are defined in Section 15.0.6.

15.1.5.2 Method of Analysis

The analysis of the steam line rupture is performed in the following stages:

1. The RETRAN code (References 15.1-1 and 15.1-4) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steam line break.

2. The RETRAN code is also used in the analysis of the steamline rupture with FFBT to calculate the primary flow coastdown initiated at the turbine trip, which results in two of the four reactor coolant pumps coasting down.

3. The RETRAN code is also used to calculate the primary flow coastdown following reactor trip as a result of the loss of offsite power, which results in all four of the reactor coolant pumps coasting down.

4. The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The VIPRE code (see Section 15.0.14.5) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the Revised Thermal Design Procedure (Reference 15.1-2). Plant characteristics and initial conditions are provided in Table 15.0-27.

The following assumptions are made in the transient analysis for the SLB with FFBT case:

1. Initial Conditions - The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their EPU values. The full power condition is more limiting than part-power in terms of DNBR. The RCS Minimum Measured Flow is used. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 15.1-2.

2. Break size - A spectrum of break sizes is analyzed. Small breaks do not result in a reactor trip. Intermediate and large size breaks result in a reactor trip on Variable High Power (VHP) due to the implementation of integral flow restrictors within the steam generators. A Low Steam Generator Pressure Trip is also available.

3. Break flow - In computing the steam flow during a steam line break, the Moody curve (Reference 15.1-3) for fL/D = 0 is used.

4. Reactivity Coefficients - The analysis is performed over a range of moderator density coefficients (MDCs) which bound end-of-cycle reactivity feedback coefficients with the minimum Doppler power feedback to maximize the power increase following the break.

5. Protection System - This analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by a reactor trip. Other protection system features are actuated to mitigate the effects of the steam line break for a post-trip condition

6. Control Systems - The results of the analysis would not be more severe as a result of control system actuation, therefore their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.

7. Fast Bus Transfer Failure – The failure of the fast bus transfer at the time of reactor trip breaker opening is modeled, which results in two of the four reactor coolant pumps coasting down. The remaining two reactor coolant pumps are assumed to coast down 3 seconds following the time of reactor trip breaker opening due to the loss of offsite power.

8. In RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the two-pump coastdown.

9. In RETRAN, the transient nuclear power prediction assumes a minimum scram reactivity worth based upon the most bottom-peaked axial power distribution. In VIPRE, the DNBR calculations are based on a top-peaked axial power distribution.

10. In VIPRE, the peak power assembly with the peak rod at the radial peaking factor (Fr) design limit and a low peak-to-average power ratio is modeled at the core location corresponding to the minimum flow assembly.

11. In estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate Fr corresponding to the DNB SAFDL. By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

The following assumptions are made in the transient analysis for the case of SLB coincident with LOOP:

1. Initial Conditions - The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their EPU values. The RCS flow is assumed to be the minimum measured flow. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 15.1-2.

2. Break size – A break size of 1.91 ft^2, corresponding to the maximum flow area of the steam generator integral flow restrictors is analyzed. The analyzed break size was confirmed to be the most limiting by the FFBT case break size parametric study and then examined for the LOOP case.

3. Break flow - In computing the steam flow during a steam line break, the Moody curve (Reference 15.1-3) for fL/D = 0 is used.

4. Reactivity Coefficients – The least negative value of the Doppler-only power coefficient is used, along with the most-negative MTC limit for EPU conditions (-2.9 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached and is used in this analysis since the cooler primary system water from the steam generator, due to the steam piping rupture, does not have sufficient time to result in a core water density increase prior to the reactor trip.

5. Trip Reactivity – A conservatively low trip reactivity value (5.2% $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. The value is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position.

6. Protection System - This analysis only considers the initial phase of the transient initiated from an at-power condition. Reactor trip is provided by a low RCS flow setpoint that includes harsh environmental error effects and is assumed to be 84.5% of minimum measured RCS flow.

7. Control Systems - The results of the analysis would not be more severe as a result of control system actuation. Therefore, their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.

8. Loss of Offsite Power - This analysis assumes that a loss of offsite power occurs concurrent with the steamline break event causing the four RCPs to coastdown. The statepoints from this case, that is, power, pressure, temperature and RCS flow are used to determine the resulting DNBR, as calculated by the VIPRE code.

AREVA Analyses

For the fuel transition, detailed analyses were performed with the approved Reference 15.1-7 methodology. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.1-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.1-10).

Cases were analyzed at EOC full-power initial conditions, with the TS maximum core inlet temperature and TS minimum RCS flow rate. These cases assumed an FFBT, causing a reactor coolant pump (RCP) in each loop to trip at the time of reactor trip, followed by a LOOP 3 seconds later, which tripped the remaining RCPs. Three sets of cases were analyzed for different break locations. Each set included break sizes from 0.1 ft2 to the largest steam line pipe diameter, and MTC values from -8 pcm/°F to the most-negative MTC analytical limit at full power, at each location. The locations were: EC287528

1. Breaks located inside containment (referred to as asymmetric inside breaks)

2. Breaks located upstream of the common turbine header and outside containment (referred to as asymmetric outside breaks)

3. Breaks located at the common steam line header just upstream of the turbine inlet (referred to as symmetric breaks)

The asymmetry of the first two scenarios is caused by the difference in length of steam lines connecting each steam generator (SG) to the break location.

The presence of a flow restrictor at the SG outlet nozzle precludes the need to analyze breaks even larger than the maximum steam line piping area, i.e., up to a double-ended guillotine break. Results showed that the severity of the event was clearly bounded using the break areas that were analyzed.

An additional case was analyzed, using the break size of the overall limiting case from the three scenarios above. This additional case assumed that the break occurred upstream of the common turbine header and inside containment, with a coincident LOOP at the time of the break, tripping all four RCPs. The most-negative MTC analytical limit was assumed.

The key input parameters and their values used in the analyses of this event were consistent with, or conservative relative to, the approved Reference 15.1-7 methodology. See Table 15.0-27 for key input parameter values.

- Reactor Protection System Trips – The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. For cases with a break

inside containment, harsh condition RPS setpoints were used. In addition, control rod insertion was delayed to account for the CEA holding coil release delay time. EC287528

- Gap Conductance and Fuel Thermal Properties – The fuel-to-cladding gap conductance was set to a conservatively high EOC value, and the fuel thermal properties also were set to EOC values, accounting for TCD.

- SG Tube Plugging – 0% plugging in each SG was used, because this increases the primary-to-secondary heat transfer and causes more of a primary cooldown.

- The ex-core detector NI power signals were decalibrated to account for detector shadowing from the decreasing-temperature reactor coolant flowing through the reactor vessel downcomer. In addition, the ΔT power signals from the hot and cold leg RTDs were also decalibrated, using an RTD lag time of 0 seconds for the hot leg temperatures and a maximum lag of 12 seconds for the cold leg temperatures.

- Main feedwater flow was modeled with a maximum 130%-of-nominal capacity.

- For cases with a break inside containment, a single-volume containment was modeled, using a physical volume of a nominal value plus uncertainty, with a conservatively low initial pressure and conservative (high) heat transfer from internal structures.

15.1.5.3 Results

SLB with FFBT

A spectrum of steam line breaks ranging in size from 0.1 ft^2 to 6.305 ft^2 was analyzed. Additionally, a spectrum of moderator density coefficients (MDCs) was considered, ranging from 0.0 Δk/gm/cc to 0.43 Δk/gm/cc.

The break is modeled on the steamline upstream of the Main Steam Isolation Valve (MSIV), which renders the break unisolatable. The steamline break is modeled to occur after a 10-second steady- state run. No reactor trip is predicted for cases modeling the smallest break sizes; thus, the power reaches equilibrium based on the increased steam load. For increasingly larger break sizes, the power increase until the reactor trips on the VHP signal.

The limiting case for demonstrating DNB protection is the lowest minimum DNBR and highest peak heat flux, which corresponds to the 1.91 ft^2 break at a MDC of 0.30 Δk/g/cc. The calculated time sequence of events for this case is shown in Table 15.1.5-1a. Figures 15.1.5-2a through 15.1.5-9a show the transient response for the limiting case.

SLB Coincident with LOOP

The Pre-Trip SLB with LOOP Inside Containment Break analysis is performed assuming LOOP at time of Break Initiation. The case is analyzed at a MDC of 0.30 Δk/g/cc. The calculated time sequence of events for this case is shown in Table 15.1.5-1b. Figures 15.1.5-1b through 15.1.5-7b show the transient response for the most limiting break size LOOP case.

AREVA Analyses

State-points for the DNB analyses were chosen at, or near, the time of the maximum power based on heat flux. The limiting results for each break location are given in Table 15.1.5-3. The overall limiting case was initiated from full-power conditions by a postulated 3.0 ft^2 break in a main steam line outside of the reactor containment and upstream of the main steam isolation valve (MSIV), with an MTC of -16 pcm/°F. The MDNBR was calculated to be greater than the 95/95 limit for the HTP CHF correlation, resulting in no fuel failure. The peak linear heat rate (LHR) was calculated to be less than the fuel centerline melt (FCM) limit; thus, no fuel failure due to FCM was predicted to occur.

The sequence of events for the overall limiting case is given in Table 15.1.5-2. Plots of key system parameters for the overall limiting case are shown in Figure 15.1.5-8 through Figure 15.1.5-14. Figure 15.1.5-8 shows the break, steam, and feedwater flow rates as a function of time. Figure 15.1.5-9 shows the steam generator pressures. Figure 15.1.5-10 shows the pressurizer pressure. Figure 15.1.5-11 shows the RCS loop temperatures. Figure 15.1.5-12 shows the core inlet flow rates. Figure 15.1.5-13 shows the reactivity feedback. Figure 15.1.5-14 shows the reactor power (kinetics power, and power based on heat flux). EC287528

The limiting case was rerun with the same break size (3.0 ft^2, from the asymmetric breaks outside containment), but with the most-negative MTC analytical limit, the break located inside containment, and LOOP at the time of the break.

The sequence of events for this additional case (given in Table 15.1.5-4) shows that this case tripped on Low RCS Loop Flow (harsh setpoint) at 2.33 seconds. The maximum power based on heat flux and the maximum actual power (from the kinetics model) were both 100.3% of RTP. The values of these two parameters never exceeded their initial values before the time of the break. Therefore, the MDNBR was not calculated for this transient.

15.1.5.4 Conclusions

For the SLB with FFBT, a detailed analysis to assess both the minimum DNBR and the peak linear heat rate was performed using radial and axial core peaking factors based on the statepoints generated from the limiting cases. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified to meet their respective limits on a cycle-specific basis through the WCAP-9272 reload process. The initial analysis supporting the implementation of the WCAP-9272 reload process for St. Lucie Unit 2 concludes that both the DNB design basis and the peak linear heat rate limit are met for the limiting case. Although the steamline break accident is classified as an ANS Condition III or IV event, the analysis demonstrates that the acceptance criteria for an ANS Condition II event are satisfied for all ruptures occurring from an at-power condition. This analysis bounds the ANS Condition II events of sections 15.1.4 (Inadvertent Opening of a Steam Generator Relief or Safety Valve) and 15.1.3 (Excessive Increase in Secondary Steam Flow/Excess Load).

For the coincident SLB with LOOP, a detailed analysis to assess both the minimum DNBR and the peak linear heat rate was performed using radial and axial core peaking factors based on the limiting statepoints. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified to meet their respective limits on a cycle-specific basis through the WCAP-9272 reload process. The analysis supporting the implementation of the WCAP-9272 reload process for St. Lucie Unit 2

concludes that less than 1.8% of the rods experience DNB for breaks outside containment. Additionally, it is concluded that DNB propagation will not lead to more rod failures than those calculated due to DNB for this event. Since the fuel failure is limited and DNB propagation is not postulated to occur, a coolable geometry is maintained.

Site boundary and control room doses have been evaluated using Regulatory Guide 1.183 acceptance criteria to establish fuel failure limits following a steam system pipe break event. For a main steam pipe rupture outside of containment, the allowable fuel failure limits are 1.2% for DNB and 0.29% for fuel centerline melt (CTM). For a pipe break inside of containment, the allowable fuel failure limits are 21% for DNB and 4.5% for CTM. Since the EPU analysis meets these fuel failure limits, the dose consequences would remain within Regulatory Guide 1.183 acceptance criteria.

15.1.6 POST-TRIP STEAM SYSTEM PIPING FAILURES

15.1.6.1 Accident Description

A steam line break (SLB) transient results in an uncontrolled increase in steam flow release from the steam generators, with the flow decreasing as the steam pressure drops. This steam flow release increases the heat removal from the RCS, which decreases the RCS temperature and pressure. With the existence of a negative MTC, the RCS cooldown results in a positive reactivity insertion, and consequently a reduction of the core shutdown margin for the post-trip condition. If the most reactive CEA is assumed stuck in its fully withdrawn position after reactor trip, the possibility is increased that the core may become critical and subsequently return to power. A return to power following a steam line break from the post-trip condition is a concern with the high-power peaking factors that may exist when the most reactive CEA is stuck in its fully withdrawn position. Following a steam line break, the core is ultimately shut down by the boric acid injected into the RCS by either the emergency core cooling system (safety injection) or the actuation of the Safety Injection Tanks (SITs). Additionally, the event may be terminated due to reaching a dry-out condition in the affected steam generator.

The steam line break analysis discussed herein was performed to demonstrate that core coolable geometry is maintained. Assuming the most reactive CEA is stuck in its fully withdrawn position, and applying the most limiting single failure of one safety injection train, steam line break core response cases were examined. Although DNB and fuel cladding damage are not necessarily unacceptable consequences of a steam line break transient, the analysis described herein demonstrates that there is no consequential damage to the primary system, and that the core remains in place and intact, by showing that the DNB design basis is satisfied following a steam line break.

The systems and components that provide the necessary protection against a steam line break are listed as follows:

- Safety injection system actuation by any of the following:

  Pressurizer pressure - low

  Containment pressure - high

- Closure of the main steam isolation valves (MSIVs) after receipt of any of the following:

Steam generator pressure - low

Containment pressure - high

- Closure of the main feedwater isolation valves.

Each main steam line is connected to a steam generator through an exit nozzle with an integral flow restrictor and an effective flow area of 1.91 ft^2. These flow restrictors limit the steam release rate during a steam line break transient. The nozzle flow restrictors limit the effective maximum steam line break size to 2.27 ft^2 per steam generator.

Following closure of the MSIVs (on one of the two main steam isolation signals mentioned above), steam release from the steam generator with the intact main steam line (referred to as the unaffected steam generator) is terminated. EC287528

15.1.6.2 Method of Analysis

The analysis of the steam line break transient has been performed to demonstrate that the DNB design basis is satisfied and that the peak linear heat rate does not exceed the limit value. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR (W-3 low pressure DNB correlation limit) and that the peak linear heat rate remains below the limit. The overall analysis process is described as follows.

Using the RETRAN code (References 15.1-1 and 15.1-4), transient values of key plant parameters identified as statepoints (core average heat flux, core pressure, core inlet temperature, RCS flow rate, and core boron concentration) were calculated first. Next, the advanced nodal code (ANC) core design code was used to:

- Evaluate the nuclear response to the RCS cooldown so as to verify the RETRAN transient prediction of the average core power/reactivity

- Determine the peaking factors associated with the return to power in the region of the stuck CEA

Finally, using the RETRAN-calculated statepoints and the ANC-calculated peaking factors, the detailed thermal and hydraulic computer code VIPRE was used to calculate the minimum DNBR based on the W-3 DNB correlation. The peak linear heat rate is calculated based on the results of the ANC analysis.

The following assumptions were made in the analysis of the main steam line break:

1. A hypothetical double-ended rupture (DER) of a main steam line was postulated at HZP/hot shutdown conditions. The maximum break size seen by the faulted steam generators is limited to the flow area of the integral flow restrictor 1.91 ft^2. The initial conditions correspond to a subcritical reactor, an initial vessel average temperature at the no-load value of 532°F, and no core decay heat. These conditions are conservative, compared to hot full power, for a steam line break transient because the resultant RCS cooldown does not have to remove any latent heat. Also, the steam generator water inventory is greatest at no-load conditions, which increases the capability for cooling the RCS. Thus, the analysis of the hot zero power case bounds the case of a post-trip analysis from hot full power.

2. One DER case was analyzed. A case assuming a loss of offsite power is bounded by the case assuming that offsite power is maintained throughout the event. Steam line break transients associated with the inadvertent opening of a steam dump or relief valve were not analyzed because the resultant RCS cooldown, and thus the minimum DNBR, would be less limiting compared to the DER cases.

3. Perfect moisture separation within the steam generators was conservatively assumed to preclude liquid discharge through the postulated SLB.

4. An end-of-life shutdown margin of 3.6 %Δk corresponding to no-load, equilibrium xenon conditions, with the most reactive CEA stuck in its fully withdrawn position was assumed. The stuck CEA was assumed to be in the core location exposed to the greatest cooldown; that is, related to the faulted loop. The reactivity feedback model included a positive moderator density coefficient (MDC) corresponding to an end-of-life rodded core with the most reactive CEA in its fully withdrawn position. The variation of the MDC due to changes in temperature and pressure was accounted for in the model. Figure 15.1.6-1 presents the k_{eff} versus temperature relationship at 900 psia corresponding to the assumed negative MTC plus the Doppler temperature feedback effect. The Doppler power feedback corresponding to the stuck CEA conditions is provided in Figure 15.1.6-2.

   The reactivity and power predicted by RETRAN were compared to those predicted by the ANC core design code. The ANC core analysis considered the following:

   - Doppler reactivity feedback from the high fuel temperature near the stuck CEA
   - Moderator feedback from the water conditions near the stuck CEA
   - Power redistribution effects
   - Non-uniform core inlet temperature effects

   The ANC core analysis confirmed that the RETRAN-predicted reactivity is acceptable.

5. The Moody critical flow curve was applied to conservatively maximize the break flow rate assuming no frictional losses.

6. The closure of the MSIV of the intact/unfaulted loop was conservatively modeled to be complete at 6.75 seconds after receipt of a low steam generator pressure (487 psia) signal from the same loop.

7. The safety injection pumps were assumed to provide flow to the RCS at 20 seconds after receipt of a safety injection signal on low pressurizer pressure (1638 psia). This delay accounts for signal processing and pump startup delays.

8. The minimum capability for the injection of boric acid solution, corresponding to the most restrictive single active failure in the SIS, was assumed. The assumed safety injection flow (see Figure 15.1.6-3) corresponds to the operation of one high-head safety injection pump. Boric acid solution from the refueling water tank (RWT), with a minimum concentration of 1720 ppm and a minimum temperature of 51°F, was the

assumed source of the safety injection flow. The safety injection lines downstream of the RWT were assumed to initially contain unborated water to conservatively maximize the time it takes to deliver the highly concentrated RWT boric acid solution to the reactor coolant loops.

9. Main feedwater flow equal to the nominal (100-percent power) value was assumed to initiate coincident with the postulated break. Feedwater flow was maintained until a feedwater isolation signal was generated.

10. A minimum SGTP level of 0 percent was assumed to maximize the heat transfer capabilities of the steam generators and therefore maximize the cooldown of the RCS.

11. Due to the design of the auxiliary feedwater system that automatically isolates the auxiliary feedwater from the broken loop, no auxiliary feedwater was assumed to be delivered during the event.

AREVA Analyses

For the fuel transition, detailed analyses were performed with the approved methodology (Reference 15.1-7), which consists mainly of the following computer codes. The S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures) and produce an estimated time of MDNBR. Core asymmetry was modeled by dividing the core into a sector adjacent to the affected loop and a sector adjacent to the unaffected loop. The stuck-rod region was modeled as a separate region in the affected sector. EC287528

The S-RELAP5 core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.1-9), which was used to calculate the MDNBR using the Biasi correlation (Reference 15.1-11) for the post-scram cases. The PRISM code was used to calculate power distribution information and kinetics parameters.

For the post-scram analyses, the SLB event was initiated by a postulated break in a main steam line coincident with reactor scram. The event was analyzed from both HZP and full-power conditions to assess the potential amount of fuel failure. Offsite power available and loss of offsite power cases were analyzed. For the loss of offsite power cases, loss of offsite power was assumed at event initiation. The largest break size in combination with the most-negative MTC analytical limit was analyzed. Breaks located inside or outside containment were bounded, because harsh conditions were assumed for all cases.

The input parameters and equipment states were chosen to provide conservative calculation of fuel failures. The key parameters and their values used in the analyses of this event are consistent with, or conservative relative to, the approved Reference 15.1-7 methodology. See Table 15.0-27 for key input parameter values.

- Initial Conditions – Two sets of initial conditions were analyzed. First, the event was assumed to initiate from rated power conditions with a maximum core inlet temperature. Rated power conditions (i.e., coolant temperatures) represent the largest potential cooldown and consequential reactivity insertion. A second set of conditions assumed

that the event initiated from a hot zero power condition with the TS minimum shutdown margin.

- Break Size and Location – A full double-ended guillotine break (DEGB) of a main steam line upstream of the MSIV was analyzed. The blowdown of the SG is limited by the flow area of the integral flow restrictor. This break size and location produces the largest cooldown, which maximizes the potential return-to-power. EC287528

- Break Flow – The Moody critical flow model was applied at the SG integral flow restrictor. The break was modeled to maximize the break flow and rate of cooldown. Steam-only flow out the break was also assumed, to maximize the secondary and RCS cooldown rates.

- Gap Conductance and Fuel Thermal Properties – A fuel-to-cladding gap conductance and fuel thermal properties that account for TCD were applied. An EOC gap conductance and EOC fuel properties were conservatively chosen to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback (during the return-to-power).

- Steam Generator Tube Plugging – No SGTP was assumed, so as to maximize the primary-to-secondary-side heat transfer, which exacerbates the reactivity insertion due to moderator feedback.

- Main Steam Isolation Valve Closure – Closure of the MSIVs was conservatively modeled to be complete at 7.0 seconds after the low steam generator pressure setpoint (487 psia) is reached.

- Main Feedwater – For the full-power cases, MFW flow was allowed to increase up to 130% of the nominal (full-power) value, in response to the increase in steam flow due to the SLB. For the HZP cases, MFW flow equal to the nominal (full-power) value was assumed to initiate coincident with the postulated break. Feedwater flow was maintained until a feedwater isolation signal was generated. Closure of the Main Feedwater Isolation Valves (MFWIVs) on both affected and unaffected SGs was conservatively modeled to be complete at 5.65 seconds after the low steam generator pressure setpoint (487 psia) is reached. EC287528

- Auxiliary Feedwater (AFW) – Maximum AFW flow was maintained, prior to automatic isolation of AFW on SG differential pressure, to maximize cooldown of the affected SG. AFW flow was isolated after a conservatively long time delay following the isolation signal.

Plant characteristics and initial conditions for this event are provided in Table 15.0-27.

15.1.6.3 Results

The results demonstrate that the post-trip steamline break event meets the applicable DNBR and peak linear heat rate acceptance criteria. The time sequence of events is presented in Table 15.1.6-1.

Figures 15.1.6-4 through 15.1.6-11 show the steam pressure, break flow, pressurizer pressure, pressurizer water volume, reactor vessel inlet temperature, core heat flux, core boron

concentration, and core reactivity following a double-ended rupture of a main steam line at initial no-load conditions with offsite power available (full reactor coolant flow). Steam flow from both faulted and unfaulted steam generators is restricted by the cross sectional flow area of the steam generator outlet nozzle integral flow restrictor (1.91 ft^2) Steam flow from the unfaulted steam generator is assumed to discharge through the break until steam line isolation had occurred.

AREVA Analyses

The sequences of events are summarized in Table 15.1.6-1a for the cases initiated from HZP, both with and without offsite power. Table 15.1.6-1b summarizes the sequences of events for the cases initiated from full power, both with and without offsite power. Table 15.1.6-1c summarizes the results of the analyses for this event.

The greatest challenge to the FCM limit occurred for the case initiated from HZP with offsite power available, and the greatest MDNBR challenge occurred for the case initiated from full power with offsite power available. Key system parameters illustrating the transient responses for the HZP and full-power limiting cases are presented in Figure 15.1.6-12 through Figure 15.1.6-22 and Figure 15.1.6-23 through Figure 15.1.6-32, respectively. The calculated MDNBRs were greater than the 95/95 limit for the Biasi CHF correlation; thus, no fuel failure due to DNB was predicted to occur. The peak LHRs were calculated to be less than the FCM limit; thus, no fuel failure due to FCM was predicted to occur. EC287528

15.1.6.4 Radiological Analysis

15.1.6.4.1 Background

This event consists of a double-ended break of one main steam line either inside or outside of containment. Allowable fuel failure rates due to DNB and fuel centerline melt are determined for both break locations based upon the dose limits specified in Table 6 of RG 1.183. Depending on the location of the break, the affected steam generator (SG) rapidly depressurizes and releases the initial contents of the SG to either the environment or the containment. The rapid secondary depressurization causes a reactor power transient, resulting in a reactor trip. Plant cool down is achieved via the remaining unaffected SG. The St. Lucie 2 AST dose analysis methodology is presented in NAI-1101-044, “AST Licensing Technical Report for St. Lucie Unit 2” (Reference 15.6.5-30).

15.1.6.4.2 Compliance with RG 1.183 Regulatory Positions

The MSLB dose consequence analysis followed the guidance provided in RG 1.183, Appendix E, "Assumptions for Evaluating the Radiological Consequences of a PWR Main Steam Line Break Accident," as discussed below:

1. Regulatory Position 1 - The total core inventory of the radionuclide groups utilized for determining the source term for this event is based on RG 1.183, Regulatory Position 3.1, and is provided in Table 15.0-32. The inventory provided in Table 15.0-32 is adjusted for the fraction of fuel damaged and a radial peaking factor of 1.65 is applied. The fraction of fission product inventory in the gap available for release due to DNB is consistent with Regulatory Position 3.2 and Table 3 of RG 1.183. For fuel centerline melt, the guidance provided in RG 1.183, Appendix H, Regulatory Position 1 is used to determine the release.

2. Regulatory Position 2 - Fuel damage is assumed for this event. It was determined that the activity released from the damaged fuel will exceed that released by the two iodine spike cases; therefore, the two iodine spike cases were not analyzed.

3. Regulatory Position 3 - The activity released from the fuel is assumed to be released instantaneously and homogeneously through the primary coolant.

4. Regulatory Position 4 - Iodine releases from the faulted SG and the unaffected SG to the environment (or containment) are assumed to be 97% elemental and 3% organic. These fractions apply as a result of fuel damage.

5. Regulatory Position 5.1 - The primary-to-secondary leak rate is apportioned between the SGs as specified by TS 6.8.4.l (0.5 gpm total, 0.25 gpm to any one SG). Thus, the tube leakage is apportioned equally between the two SGs.

6. Regulatory Position 5.2 - The density used in converting volumetric leak rates to mass leak rates is based upon RCS conditions, consistent with the plant design basis.

7. Regulatory Position 5.3 - The primary-to-secondary leakage is assumed to continue until after shutdown cooling has been placed in service and the temperature of the RCS is less than 212°F.

8. Regulatory Position 5.4 - All noble gas radionuclides released from the primary system are assumed to be released to the environment without reduction or mitigation.

9. Regulatory Position 5.5.1 - In the faulted SG, all of the primary-to-secondary leakage is assumed to flash to vapor and be released to the environment (MSLB outside of containment) or the containment (MSLB inside of containment) with no mitigation. For the unaffected steam generator used for plant cooldown, a portion of the leakage is assumed to flash to vapor based on the thermodynamic conditions in the reactor and secondary immediately following plant trip when tube uncovery is postulated. The primary-to-secondary leakage is assumed to mix with the secondary water without flashing during periods of total tube submergence.

10. Regulatory Position 5.5.2 - The postulated leakage that immediately flashes to vapor is assumed to rise through the bulk water of the SG into the steam space and is assumed to be immediately released to the environment with no mitigation; i.e., no reduction for scrubbing within the SG bulk water is credited.

11. Regulatory Position 5.5.3 - All leakage that does not immediately flash is assumed to mix with the bulk water.

12. Regulatory Position 5.5.4 - The radioactivity within the bulk water is assumed to become vapor at a rate that is a function of the steaming rate and the partition coefficient. A partition coefficient of 100 is assumed for the iodine. The retention of particulate radionuclides in the unaffected SG is limited by the moisture carryover from the SG. The same partition coefficient of 100, as used for iodine, is assumed for other particulate radionuclides. This assumption is consistent with the SG carryover rate of less than 1%. No reduction in the release is assumed from the faulted SG.

13. Regulatory Position 5.6 - Steam generator tube bundle uncovery in the intact SG is postulated for up to 45 minutes following a reactor trip for St. Lucie Unit 2. During this period, the fraction of primary-to-secondary leakage which flashes to vapor is assumed to rise through the bulk water of the SG into the steam space and is assumed to be immediately released to the environment with no mitigation. The flashing fraction is based on the thermodynamicconditions in the reactor and secondary coolant. The leakage which does not flash is assumed to mix with the bulk water in the steam generator. A conservative uncovery time of 60 seconds was assumed in the analysis.

15.1.6.4.3 Other Assumptions

1. The initial RCS activity is assumed to be at the TS 3.4.8 limit of 1.0 µCi/gm Dose EquivalentI-131 and 518.9 µCi/gm DE Xe-133 gross activity. The initial SG activity is assumed to be at the TS 3.7.1.4 limit of 0.1 µCi/gm Dose Equivalent I-131.

2. The steam mass release rates for the intact SG are provided in Table 15.1.6-4.

3. The RCS fluid density used to convert the primary-to-secondary leakage from a volumetric flowrate to a mass flow rate is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. The high initial cooldown rate conservatively maximizes the fluid density. The SG tube leakage mass flow rate is provided in 15.1.6-5.

4. This RCS mass is assumed to remain constant throughout the MSLB event (no change in the RCS mass is assumed as a result of the MSLB or from the safety injection system).

5. For the purposes of determining the iodine concentration of the SG secondary, the mass in the unaffected SG is assumed to remain constant throughout the event. However, it is also assumed that operator action is taken to restore water level above the top of the tubes in the unaffected steam generator within a conservative time of one hour following a reactor trip.

6. All secondary releases are postulated to occur from the ADV with the most limiting atmospheric dispersion factors. Releases from containment through the SBVS are assumed to be released from the plant stack with a filter efficiency of 99% for particulates and 95% for both elemental and organic iodine. The activity that bypasses the SBVS is released unfiltered to the environment via a ground level release from containment.

7. The initial leakage rate from containment is 0.5% of the containment air per day. This leak rate is reduced by 50% after 24 hours to 0.25% /day. 9.6% of the containment leakage is assumed to bypass the SBVS filters.

8. For the MSLB inside of containment, natural deposition of the radionuclides is credited. Containment sprays are not credited.

15.1.6.4.4 Methodology

Input assumptions used in the dose consequence analysis of the MSLB are provided in Table 15.1.6-3. The postulated accident consists of two cases; one case is based upon a double-ended break of one main steam line outside of containment, and the second case is based upon a double- ended break of one main steam line inside of containment. The primary difference between these two models is the transport of the primary-to-secondary leakage through the affected steam generator. Upon a MSLB, the affected SG rapidly depressurizes. The rapid secondary depressurization causes a reactor power transient, resulting in a reactor trip. Plant cooldown is achieved via the remaining unaffected SG.

The analysis for both cases assumes that activity is released as reactor coolant enters the steam generators due to primary-to-secondary leakage. All noble gases associated with this leakage are assumed to be released directly to the environment. For the break outside containment, primary-to- secondary leakage into the affected steam generator is also assumed to directly enter the atmosphere. For the break inside containment, the affected steam generator leakage is released into containment. All primary-to-secondary leakage is assumed to continue until the faulted steam generator is completely isolated at 12 hours.

Primary-to-secondary tube leakage is also postulated to occur in the unaffected SG for both cases. This activity is diluted by the contents of the steam generator and released via steaming from the ADVs until the RCS is cooled to 212°F. In addition, the analysis of both cases assumes that the initial iodine activity of both SGs is released directly to the environment. The entire contents of the faulted steam generator is released immediately, while the intact steam generator release occurs during the RCS cooldown. The secondary coolant iodine concentration is assumed to be the maximum value of 0.1 μCi/gm DE I-131 permitted by Technical Specifications. These release assumptions are consistent with the requirements of RG 1.183.

Allowable levels of fuel failure for DNB and fuel centerline melt are determined for both the MSLB outside of containment and the MSLB inside of containment. These allowable fractions are based on the dose limits specified in Table 6 of RG 1.183. The activity released from the fuel that is assumed to experience DNB is based on Regulatory Positions 3.1, 3.2, and Table 3 of RG 1.183. The activity released from the fuel that is assumed to experience fuel centerline melt is based on Regulatory Position 1 of Appendix H to RG 1.183.

For this event, the Control Room ventilation system cycles through three modes of operation:

- Initially the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 395 cfm of unfiltered inleakage.

- After the start of the event, the Control Room is isolated due to a high radiation reading in the Control Room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 395 cfm of unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

- At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside to the control room. During this operational mode, the air flow distribution

consists of up to 504 cfm of filtered makeup flow, 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.

- The Control Room ventilation filter efficiencies that are applied to the filtered makeup and recirculation flows are 99% for particulate, and 95% for elemental iodine, and organic iodine.

15.1.6.4.5 Radiological Consequences

The Control Room atmospheric dispersion factors (χ/Qs) used for this event are based on the postulated release locations and the operational mode of the control room ventilation system. The release-receptor point locations are chosen to minimize the distance from the release point to the Control Room air intake.

For the MSLB, all secondary releases are assumed to occur from the ADV that produces the most limiting χ/Qs. When the Control Room Ventilation System is in normal mode, the most limiting χ/Q corresponds to the worst air intake to the control room. When the ventilation system is isolated, the limiting χ/Q corresponds to the midpoint between the two control room air intakes. The operators are assumed to reopen the most favorable air intake at 1.5 hours. Development of control room atmospheric dispersion factors is discussed in Appendix 2.5D. The χ/Qs for the secondary releases are summarized in Table 15.1.6-7. For the MSLB inside of containment, the χ/Qs for containment leakage are assumed to be identical to those for the LOCA discussed in Section 15.6.5.5.4.

For the EAB dose analysis, the χ/Q factor for the zero to two-hour time interval is assumed for all time periods. Using the zero to two-hour χ/Q factor provides a more conservative determination of the EAB dose, because the χ/Q factor for this time period is higher than for any other time period. The LPZ dose is determined using the χ/Q factors for the appropriate time intervals. These χ/Q factors are provided in Appendix 2.5C.

The radiological consequences of the MSLB Accident are analyzed using the RADTRAD-NAI code and the inputs/assumptions previously discussed. Cases for MSLB inside and outside of containment with DNB and FCM fuel failure are analyzed. As shown in Table 15.1.6-2, the results of all four cases for EAB dose, LPZ dose, and Control Room dose are within the appropriate regulatory acceptance criteria.

15.1.6.5 Conclusions

The main steam line break transient was conservatively analyzed with respect to the reactor core response. Key analysis assumptions were made to conservatively maximize the cooldown of the RCS, so as to maximize the positive reactivity insertion, and thus maximize the peak return to power. Other key assumptions include: end-of-life shutdown margin with the most-reactive CEA stuck in its fully withdrawn position, maximum delays in actuating engineered safeguard features such as safety injection, main steam isolation and feedwater isolation, and minimum safety injection flow with a minimum boron concentration.

Site boundary and control room doses have been evaluated using Regulatory Guide 1.183 acceptance criteria to establish fuel failure limits following a steam system pipe break event. For a main steam pipe rupture outside of containment, the allowable fuel failure limits are 1.2% for DNB and 0.29% for fuel centerline melt (CTM). For a pipe break inside of containment, the allowable fuel failure limits are 21% for DNB and 4.5% for CTM.

A DNBR statepoint analysis was performed for the post-trip steamline break event with offsite power. The case with offsite power available—that is, the case with full reactor coolant flow—was found to be the limiting case. The minimum DNBR was determined to be greater than the DNBR safety analysis limit, and thus the DNB design basis is met. Additionally, the peak linear heat rate was demonstrated not to exceed the limit value.

15.1.7 REFERENCES

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15.1-4 EPRI NP-1850-CCM, Rev. 6, “RETRAN-02 – A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems,” December 1995.

15.1-5 B. T. Moroney to J. A. Stall, “St. Lucie Plant, Unit No.2 – Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC NO. MC1566),” dated January 31, 2005.

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15.1-7 EMF-2310(P)(A) Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

15.1-8 ANP-3347P Revision 0, St. Lucie Unit 2 Fuel Transition Chapter 15 Non LOCA Summary Report, AREVA Inc., December 2014.

15.1-9 XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, August 1983. EC287528

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15.1-11 L. Biasi, et. al., “Studies on Burnout, Part 3 – A New Correlation for Round Ducts and Uniform Heating and Its Comparison with World Data,” Energia Nucleare, Volume 14, No. 9, September 1967.

Table 15.1.1-1 Feedwater System Malfunction Event at Full Power, Reduced Feedwater Temperature Sequence of Events

Event	Time* (seconds)
MFW Temperature Reduced in Loops 1 and 2	100.010
Variable High Power Trip Setpoint Reached	145.498
CEAs Begin to Drop Into Core	146.638
Minimum DNBR Reached	146.600
Turbine Trip Occurs	147.898

* - A 100 second steady state time period is included.

Table 15.1.1-2 Reduced Feedwater Temperature (AREVA): Sequence of Events

Event	Time (sec)
Loss of feedwater heaters occurs	0.00
VHP trip setpoint is reached	43.58
Reactor is scrammed on VHP (including signal processing delay)	44.00
CEA insertion begins	44.75
Minimum (prior to scram) core inlet temperature is reached	44.75
Peak neutronic power occurs	44.78
MDNBR occurs	44.80
Maximum clad surface heat flux occurs	44.83

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Table 15.1.1-3 Reduced Feedwater Temperature (AREVA): Results

Criterion	Result
MDNBR	1.257
Peak LHR	18.24 kW/ft

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Table 15.1.2-1 Feedwater System Malfunction Event at Full Power, Increased Feedwater Flow Sequence of Events

Event	Time* (seconds)
MFW Flow in Loops 1 and 2 Reaches 120% of the Nominal HFP Value	100.010
Variable High Power Trip Setpoint Reached	139.446
CEAs Begin to Drop into Core	140.586
Minimum DNBR Reached	140.600
Turbine Trip Occurs	141.846

* - A 100 second steady state time period is included.

Table 15.1.2-2 Increased Feedwater Flow (AREVA): Sequences of Events

Case	Event	Time (sec)
Full Power	Increase in feedwater flow occurs	0.00
	VHP trip setpoint is reached	32.08
	Reactor is scrammed on VHP (including signal processing delay)	32.48
	CEA insertion begins	33.23
	Minimum (prior to scram) core inlet temperature is reached	33.23
	Peak neutronic power occurs	33.24
	Maximum clad surface heat flux occurs	33.29
	MDNBR occurs	33.30
Hot Zero Power	Increase in feedwater flow occurs	0.00
	VHP trip setpoint is reached	24.75
	Peak neutronic power occurs	24.85
	MDNBR occurs	24.95
	Maximum clad surface heat flux occurs	24.97
	Reactor is scrammed on VHP (Note 1)	25.15
	CEA insertion begins	26.59
	Maximum fuel centerline temperature occurs	29.30
	Scram is complete	29.44
	SG level reaches 100% NR span, and MFW is isolated	29.53

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Note 1: For this HZP case, an additional delay time of 0.7 seconds was added between the reactor scram and initiation of CEA insertion (when compared to the HFP case), because the analysis of this case lumped the 0.7-second HZP VHP bypass removal delay together with the 0.74-second scram CEA holding coil release delay.

Table 15.1.2-3 Increased Feedwater Flow (AREVA): Results

Case	Criterion	Result
Full Power	MDNBR	1.220
	Peak LHR	18.50 kW/ft
Hot Zero Power	MDNBR	5.857
	Peak CLT	3385ºF

EC287528

Table 15.1.3-1 Increased Steam Flow: Sequences of Events		
Case	Event	Time (sec)
Hot Zero Power	Turbine control valves fully open, and AFW is initiated at maximum delivery	0.00
	VHP trip setpoint is reached	11.54
	Peak neutronics power occurs	11.65
	Maximum cladding surface heat flux occurs	11.75
	MDNBR occurs	11.75
	Reactor is scrammed on VHP (Note 1)	11.95
	CEAs began to drop	13.40
	Maximum fuel centerline temperature occurs	16.1
	Scram is completed	16.25
	MS isolation setpoint is reached	25.32
	SI actuation setpoint is reached, and RCPs are tripped	28.35
	MSIVs are fully closed (Note 2)	39.1
	HPSI flow begins	48.36
	Calculation is terminated	48.84
Full Power	SBCS valves fully open	0.00
	Peak steam flow through SBCS valves and TCV occurs	0.1
	Maximum MFW flow occurs	6.7
	VHP trip setpoint is reached	25.7
	Reactor is scrammed on VHP	26.1
	CEAs start to drop into core	26.84
	Minimum core inlet temperature (pre-scram) is reached	26.84
	Peak neutronics power occurs	26.85
	Maximum cladding surface heat flux occurs	26.9
	MDNBR occurs	26.90
	CEAs are fully inserted	29.69

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Note 1: For this HZP case, an additional delay time of 0.7 seconds was added between the reactor scram and initiation of CEA insertion (when compared to the HFP case), because the analysis of this case lumped the 0.7-second HZP VHP bypass removal delay together with the 0.74-second scram CEA holding coil release delay.

Note 2: The time between reaching the MS isolation setpoint and full closure of the MSIVs conservatively bounds the TS.

Table 15.1.3-2 Increased Steam Flow: Results		
Case	Criterion	Result
Full Power	MDNBR	1.271
	Peak LHR	19.12 kW/ft
Hot Zero Power	MDNBR	3.880
	Peak CLT	3491ºF

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Table 15.1.5-1a Pre-Trip Steam Line Break Analysis with FFBT Sequence of Events (1.91 ft^2 break)		
Event	**Time* (sec)**	**Value**
MSLB Transient Initiated	10.01	---
Variable High Power (Thermal) Power Setpoint Reached	21.29	112%
Reactor Trip Signal Generated	21.69	0.40 second delay from setpoint
FFBT Occurs - One RCP in Each Loop Coasts Down	21.70	FFBT assumed coincident with reactor trip breaker opening
CEA Release	22.68	0.99 second delay is conservatively used instead of 0.74 seconds delay design basis value
Loss of Offsite Power Occurs - Remaining RCPs Coast Down	24.70	LOOP assumed 3 seconds after reactor trip breaker opening
Minimum DNBR Reached	22.35	1.63
Peak Linear Heat Rate Reached	22.35	17.677 kW/ft
Peak Heat Flux Reached	22.35	122.9%

* A 10 second steady state time period is included.

Table 15.1.5-1b Pre-Trip Steamline Break Analysis with a LOOP at Break Initiation Sequence of Events (1.91 ft^2 break)		
Event	**Time* (sec)**	**Value**
MSLB Transient Initiated	10.01	---
Low Flow Offsite Power (All RCPs Begin to Coast Down)	10.01	LOOP assumed coincident with MSLB initiation
Low RCS Flow Setpoint Reached	11.77	84.5% of initial MMF (includes harsh environment factor)
Reactor Trip Signal Generated	12.67	0.90 second delay from setpoint
CEA Release	13.66	0.99 second delay conservatively used instead of 0.74 second delay design basis value
Minimum DNBR Reached	14.10	1.76
Peak Linear Heat Rate Reached	14.10	<17.677 kW/ft

* A 10 second steady state time period is included.

Table 15.1.5-2 Pre-Trip Steam Line Break (AREVA): Sequence of Events	
Event	Time (sec)
With reactor at full-power / -16 pcm/°F MTC condition, postulated 3.0 ft^2 break in main steam line outside containment and upstream of MSIV occurs	0.00
Indicated power (ΔT signal) reaches VHP trip setpoint	29.01
Reactor trip signal (on VHP) is received, and turbine is tripped	29.41
FFBT causes RCPs in Loops 1A and 2A to trip	29.42
Core power based on heat flux reaches maximum value	29.45
Insertion of scram CEAs begins	30.16
MDNBR occurs	30.50
LOOP occurs, and RCPs in Loops 1B and 2B are tripped	32.42

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Table 15.1.5-3 Pre-Trip Steam Line Break (AREVA): Results		
Case	Criterion	Result
Asymmetric Inside Containment (1.0 ft^2, -33 pcm/°F)	MDNBR (% fuel failure)	1.381 (0%)
	Peak LHR (% fuel failure)	Bounded (Note 2)
Asymmetric Inside Containment (1.5 ft^2, -33 pcm/°F)	MDNBR (% fuel failure)	1.431 (0%)
	Peak LHR (% fuel failure)	Bounded (Note 2)
Asymmetric Outside Containment (3.0 ft^2, -16 pcm/°F)	MDNBR (% fuel failure)	1.277 (Note 1) (0%)
	Peak LHR (% fuel failure)	17.67 kW/ft (0%)
Symmetric Outside Containment (5.0 ft^2, -12 pcm/°F)	MDNBR (% fuel failure)	1.203 (Note 1) (0%)
	Peak LHR (% fuel failure)	Bounded (Note 2)

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Note 1: Although the symmetric outside containment (5.0 ft^2, -12 pcm/°F MTC) case shows the lowest MDNBR in this table, this is only due to conservatisms in the analysis. The analysis shows that the asymmetric outside containment (3.0 ft^2, -16 pcm/°F MTC) case is the true limiting case.

Note 2: Bounded by the value for the asymmetric outside containment 3.0 ft^2 break with -16 pcm/°F MTC.

Table 15.1.5-4 Pre-Trip Steam Line Break with LOOP at Initiation (AREVA): Sequence of Events	
Event	Time (sec)
With reactor at full-power / -33 pcm/°F MTC condition, postulated 3.0 ft^2 break in main steam line inside containment occurs. Simultaneous loss of offsite power occurs. All RCPs begin coasting down. Core power based on heat flux is at maximum value.	0.00
RCS flow reaches RPS Low Flow setpoint (87.4% with harsh conditions).	1.43
Reactor trip signal (on Low Flow) is received, and turbine is tripped.	2.33
Insertion of scram CEAs begins.	3.08
Transient analysis is terminated.	13.1

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Table 15.1.6-1 Post-Trip Steam Line Break Analysis Sequence of Events (1.91 ft^2 break)		
Event	**Time* (sec)**	**Value**
MSLB ((1.91 ft^2 DER) Transient Initiated	10.0	---
Manual Reactor Trip	10.0	---
MSIV/MFIV Closure Signal on Low Steam Generator Pressure	21.6	487 psia
SI Actuation Signal on Low Pressurizer Pressure	26.1	1638 psia
Feedwater Isolation	26.8	5.15 sec. delay
Steamline Isolation (MSIV Closure) on Loops 1 and 2	28.4	6.75 sec. delay
Core Criticality Attained	182.0	---
Peak Heat Flux Reached	520.0	6.0%
Minimum DNBR Reached	520.0	3.611
Peak Linear Heat Rate Reached	520.0	11.41 kW/ft

* A 10 second steady state time period is included.

Table 15.1.6-1a Post-Trip Steam Line Break (AREVA): HZP Sequences of Events		
	HZP Offsite Power Available	HZP Loss of Offsite Power
Event	Time (sec)	Time (sec)
DEGB occurs in main steam line upstream of MSIV; reactor is tripped	0.00	0.00
CEA insertion begins	0.00	0.00
CEAs are fully inserted	0.01	0.01
Low SG pressure MS/MFW isolation setpoint is reached	9.44	8.72
Low pressurizer pressure SI actuation setpoint is reached	14.36	18.09
MFWIVs are closed; AFW flow begins	15.09	14.37
MSIVs are closed	16.44	15.72
Unaffected sector core inlet temperature reaches minimum	21.0	40.6
HPSI begins (unborated water begins to clear from SI lines)	34.4	48.1
Shutdown worth is fully overcome by moderator and Doppler feedback	76.2	169.6
High SG ΔP AFW isolation setpoint is reached	90.3	62.3
AFW to affected SG is isolated	290.3	262.3
Peak post-scram reactor power occurs	293.6	340.6
MDNBR occurs	293.6	340.6
Borated HPSI flow begins (unborated water is cleared from SI lines)	303.7	304.7

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Table 15.1.6-1b Post-Trip Steam Line Break (AREVA): Full-Power Sequences of Events		
Event	Full Power Offsite Power Available Time (sec)	Full Power Loss of Offsite Power Time (sec)
DEGB occurs in main steam line upstream of MSIV	0.00	0.00
Reactor and turbine are tripped	0.00	0.00
CEA insertion begins	0.74	0.74
CEAs are fully inserted	3.59	3.59
Low SG pressure MS/MFW isolation setpoint is reached	13.85	11.62
Low pressurizer pressure SI actuation setpoint is reached	14.06	15.64
MFWIVs are closed; AFW flow begins	19.50	17.27
MSIVs are closed	20.85	18.62
Unaffected sector core inlet temperature reaches minimum	25.2	46.2
Credited HPSI pump is available (but RCS pressures are higher than HPSI pump shutoff head)	34.1	45.6
High SG ΔP AFW isolation setpoint is reached	89.2	51.1
Shutdown worth is fully overcome by moderator and Doppler feedback	194.2	464.0
AFW to affected SG is isolated	289.2	251.1
Peak post-scram reactor power occurs	293.2	885.0
MDNBR occurs	293.2	885.0

EC287528

Table 15.1.6-1c Post-Trip Steam Line Break (AREVA): Results		
Case	Criterion	Result
Full Power Offsite Power Available	MDNBR (% fuel failure)	1.740 (0%)
	Peak LHR (% fuel failure)	16.35 kW/ft (0%)
Full Power Loss of Offsite Power	MDNBR (% fuel failure)	6.331 (0%)
	Peak LHR (% fuel failure)	9.83 kW/ft (0%)
HZP Offsite Power Available	MDNBR (% fuel failure)	1.979 (0%)
	Peak LHR (% fuel failure)	17.02 kW/ft (0%)
HZP Loss of Offsite Power	MDNBR (% fuel failure)	11.215 (0%)
	Peak LHR (% fuel failure)	7.43 kW/ft (0%)

EC287528

TABLE 15.1.6-2

MSLB Dose Consequences

Case	Fuel Failure	EAB Dose[1] (rem TEDE)	LPZ Dose[2] (rem TEDE)	Control Room Dose[2] (rem TEDE)
MSLB – Outside of Containment	1.2% DNB	0.27	0.76	4.36
MSLB – Outside of Containment	0.29% FCM	0.30	0.81	4.45
MSLB – Inside of Containment	21% DNB	0.41	0.88	4.46
MSLB – Inside of Containment	4.5% FCM	0.64	1.23	4.45
Acceptance Criteria		25	25	5

[1] Worst 2-hour dose

[2] Integrated 30-day dose

TABLE 15.1.6-3
Main Steam Line Break (MSLB) - Inputs and Assumptions

Input/Assumption	Value
Core Power Level	3030 MW_{th} (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o
Maximum Radial Peaking Factor	1.65
% DNB for MSLB Outside of Containment	1.2%
% DNB for MSLB Inside of Containment	21%
% Fuel Centerline Melt for MSLB Outside of Containment	0.29%
% Fuel Centerline Melt for MSLB Inside of Containment	4.5%
Core Fission Product Inventory	Table 15.0-32
Initial RCS Equilibrium Activity	1.0 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 (Table 15.6.5-15)
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/gm DE I-131 (Table 15.1.6-6)
Release Fraction from DNB Fuel Failures	RG 1.183, Section 3.2
Release Fraction from Centerline Melt Fuel Failures	RG 1.183, Section 3.2, and Section 1 of Appendix H
Steam Generator Tube Leakage	0.25 gpm per SG (Table 15.1.6-5)
Time to Terminate SG Tube Leakage	12.4 hours
Steam Release from Intact SGs	Table 15.1.6-4
Intact SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	 1 hour 6%
Steam Generator Secondary Side Partition Coefficient	Unaffected SG - 100 Faulted SG - None
Time to Reach 212 °F and Terminate Steam Release	12.4 hours
Containment Volume Containment Leakage Rate 0 to 24 hours after 24 hours	2.50E+06 ft^3 0.5% (by volume)/day 0.25% (by volume)/day
Secondary Containment Filter Efficiency	Particulate – 99% Elemental – 95% Organic – 95%
Secondary Containment Drawdown Time	310 seconds
Secondary Containment Bypass Fraction	9.6%
RCS Mass	386,354 lb_m Minimum mass used for fuel failure dose contribution to maximize SG tube leakage activity.

TABLE 15.1.6-3 (continued)

Main Steam Line Break (MSLB) - Inputs and Assumptions

Input/Assumption	Value
SG Secondary Side Mass	minimum – 121,970 lb_m (per SG) maximum – 219,009 lb_m (per SG) Maximum mass used for faulted SG to maximize secondary side dose contribution. Minimum mass used for intact SG to maximize steam release nuclide concentration.
Chemical Form of Iodine Released from SGs	Particulate – 0% Elemental – 97% Organic – 3%
Atmospheric Dispersion Factors Offsite Onsite	 Appendix 2.5C Table 15.1.6-7 and Appendix 2.5D
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	 30 seconds 1.5 hours 395 cfm
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6
Control Room Occupancy Factor	RG 1.183 Section 4.2.6
Containment Natural Deposition Coefficients	Aerosols – 0.1 hr^{-1} Elemental Iodine – 2.89 hr^{-1} Organic Iodine – None

TABLE 15.1.6-4

Intact Steam Generator Steam Release Rates

Time (hours)	Release Rate (lbm/min)
0.0	9087.1
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0

TABLE 15.1.6-5

Intact Steam Generator Tube Leakage

Time (hours)	SG Tube Leakage (lbm/min)
0	1.58
0.50	1.67
1.00	1.75
1.50	1.83
2.00	1.86
4.00	1.90
6.00	1.94
9.00	1.98
11.00	2.00
12.40	0.00

TABLE 15.1.6-6

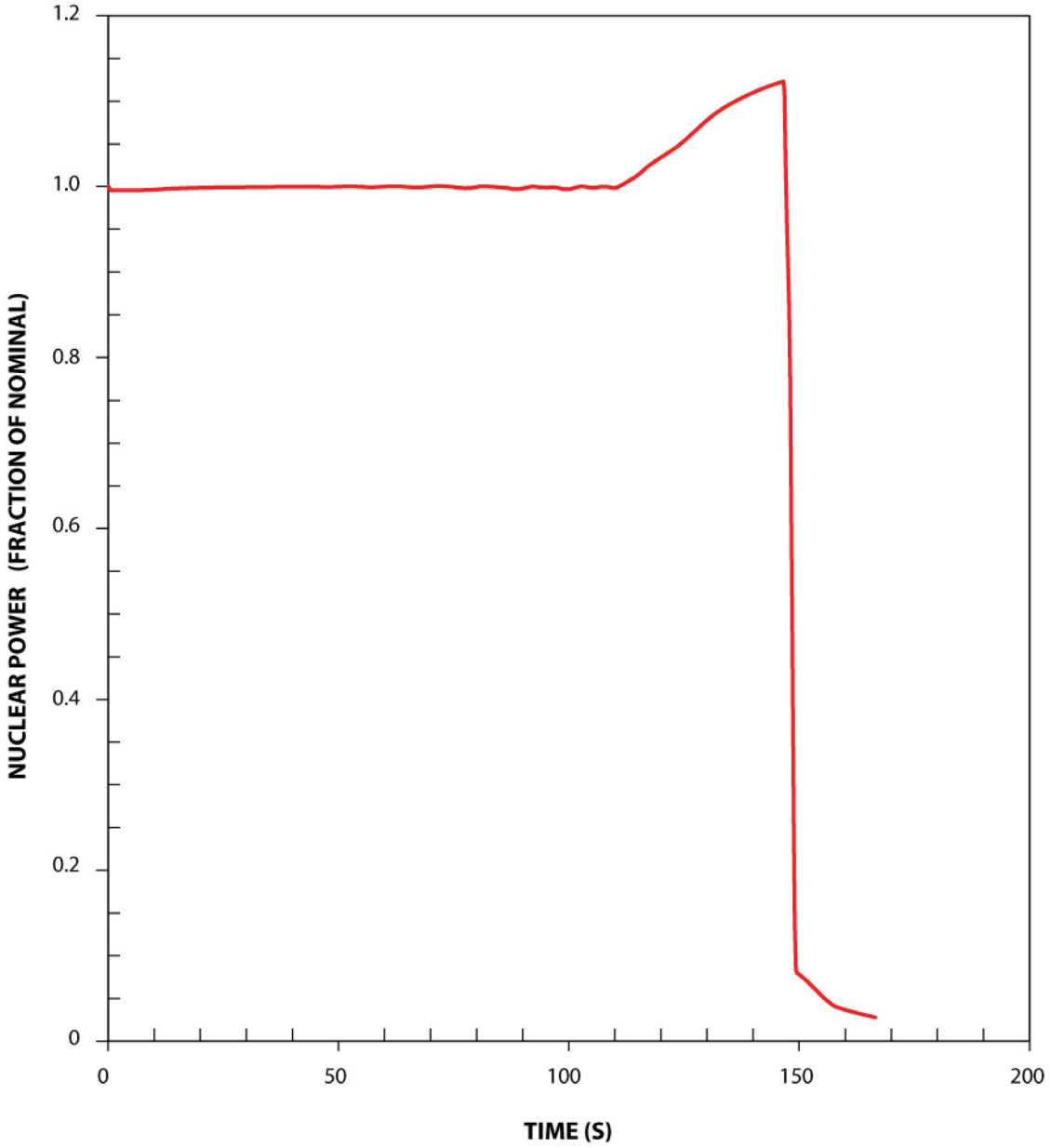
Secondary Side Source Term

Nuclide	μCi/gm
I-131	8.425E-02
I-132	1.689E-02
I-133	8.713E-02
I-134	7.73E-03
I-135	3.933E-02

TABLE 15.1.6-7

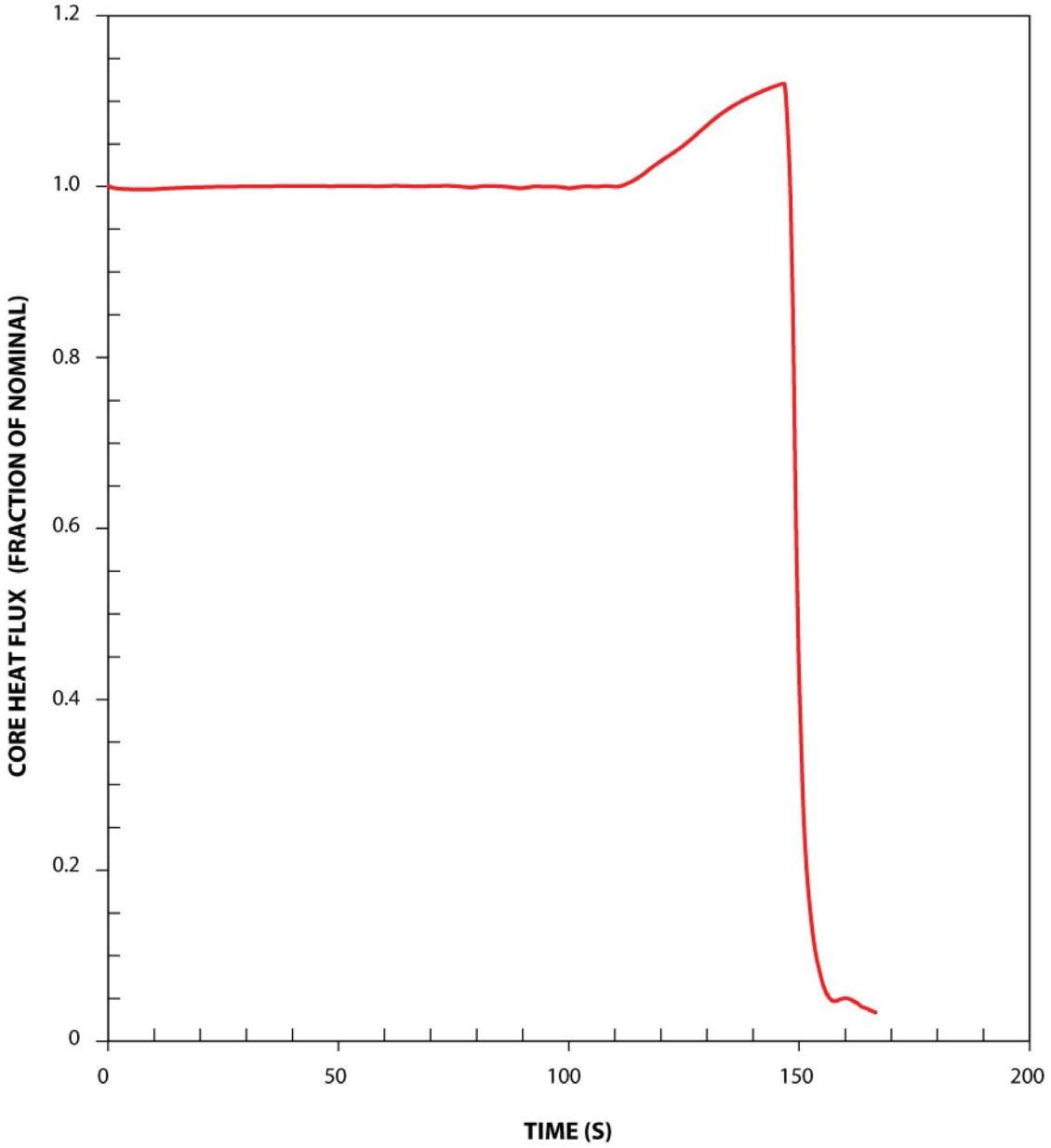
Control Room X/Qs (for releases from the SG)

Time (hours)	X/Q (sec/m^3)
0	6.71E-03
0.00833	3.13E-03
1.5	1.89E-03
2	1.53E-03
8	6.02E-04
24	4.55E-04
96	3.89E-04
720	3.89E-04



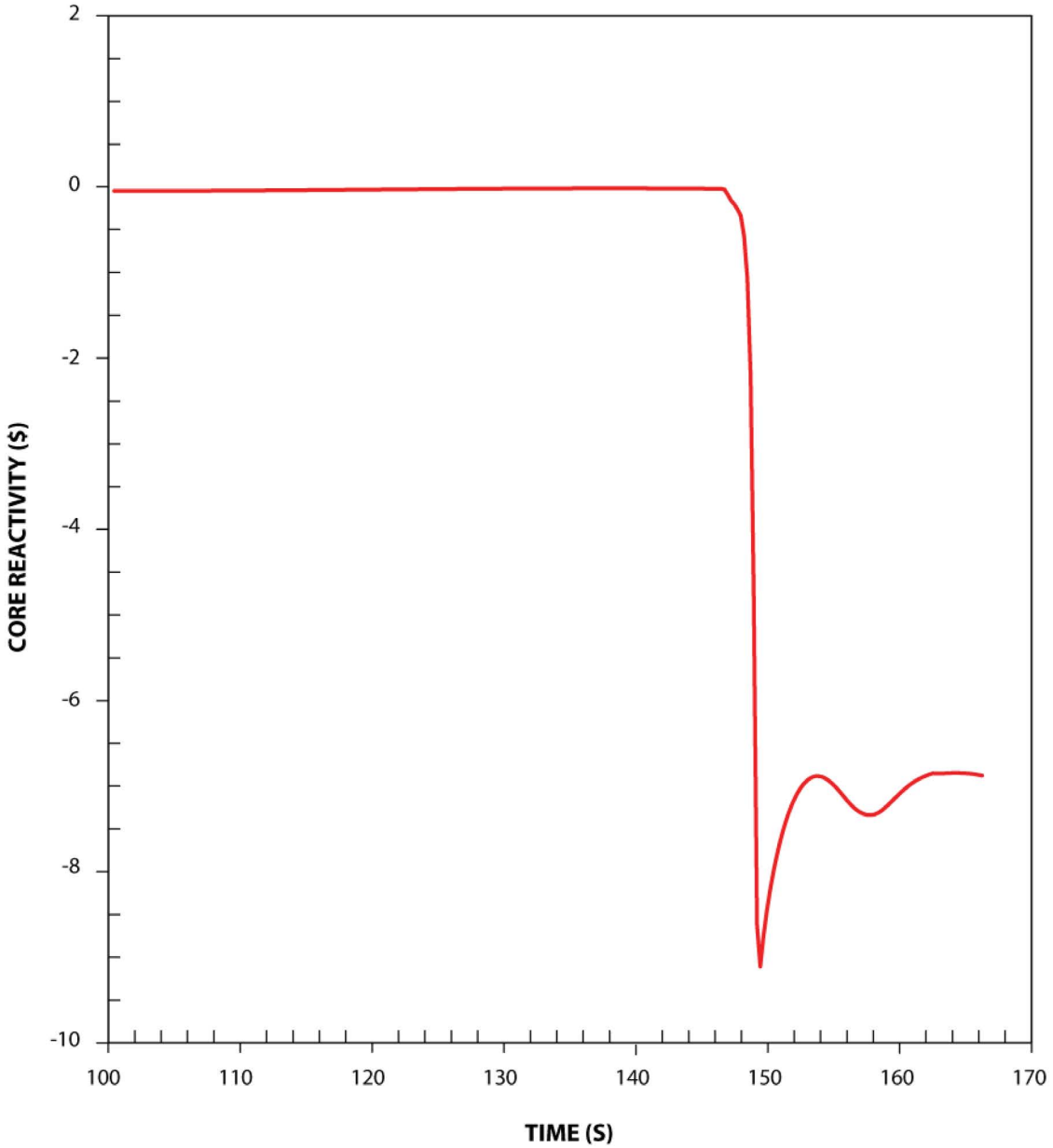
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-1 Feedwater Malfunction – Reduced Feedwater Temperature at HFP Nuclear Power vs. Time

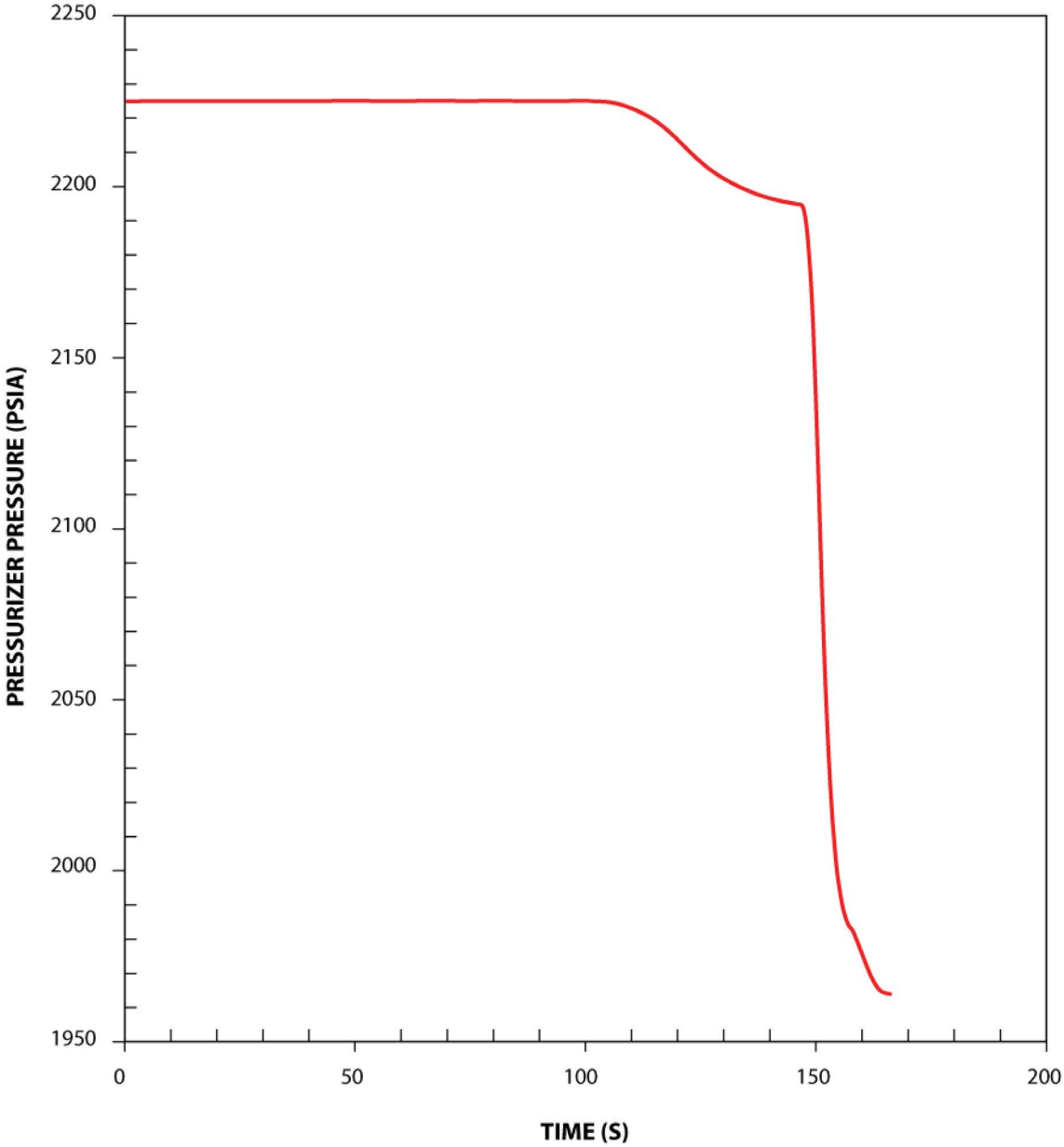


Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-2 Feedwater Malfunction – Reduced Feedwater Temperature at HFP Core Heat Flux vs. Time

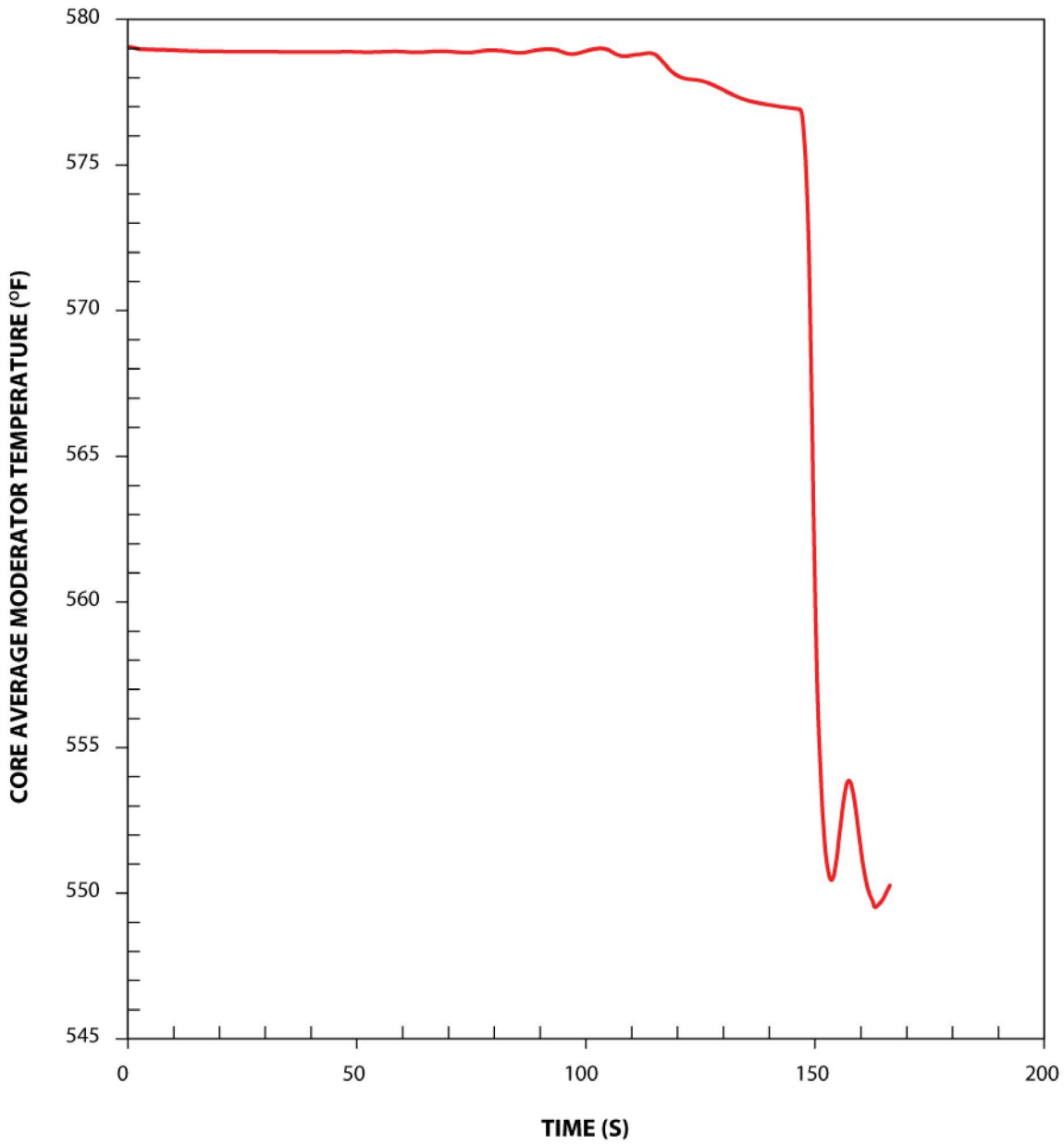


FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-3 Feedwater Malfunction – Reduced Feedwater Temperature at HFP Core Reactivity vs. Time



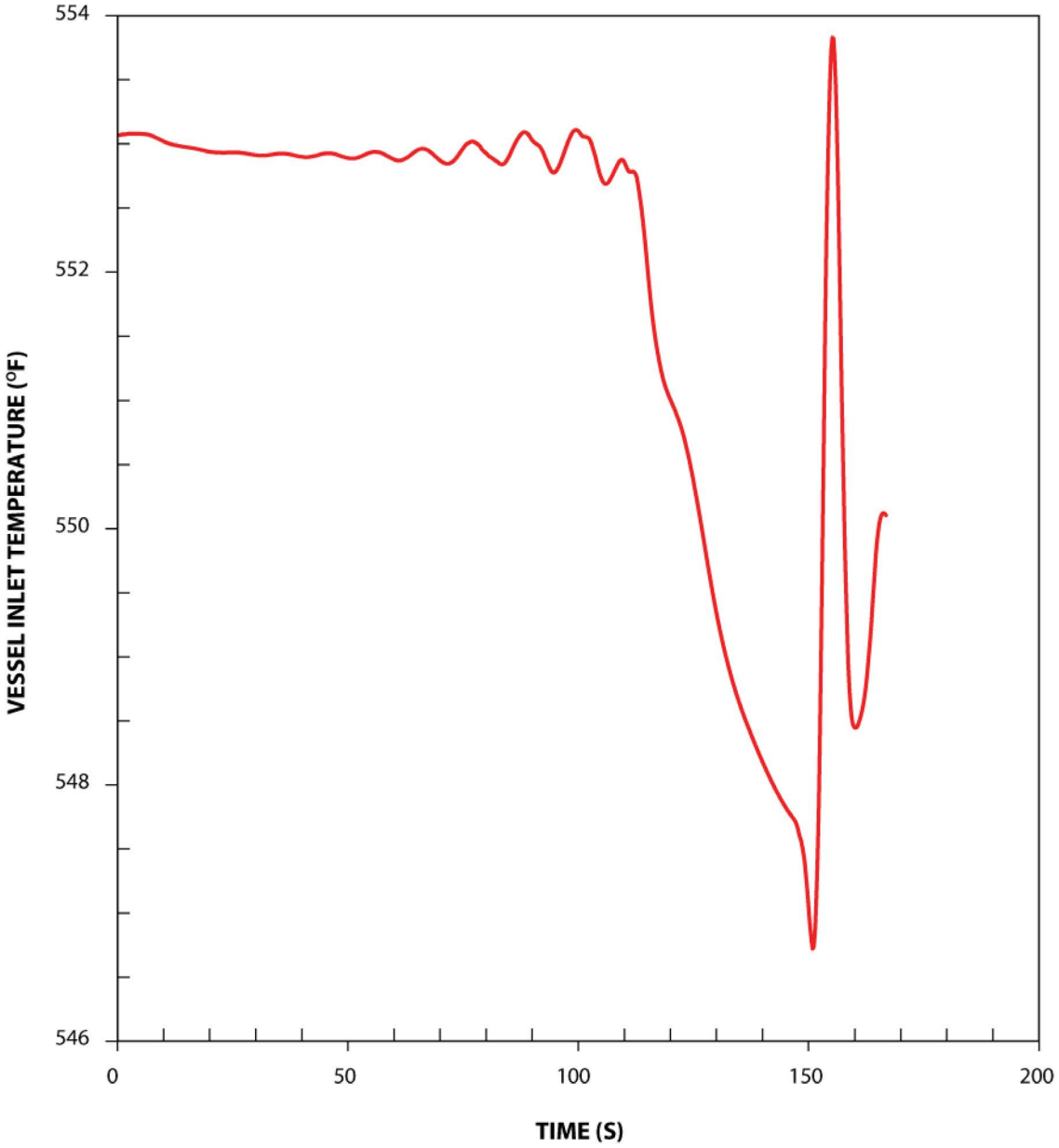
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-4 Feedwater Malfunction – Reduced Feedwater Temperature at HFP Pressurizer Pressure vs. Time



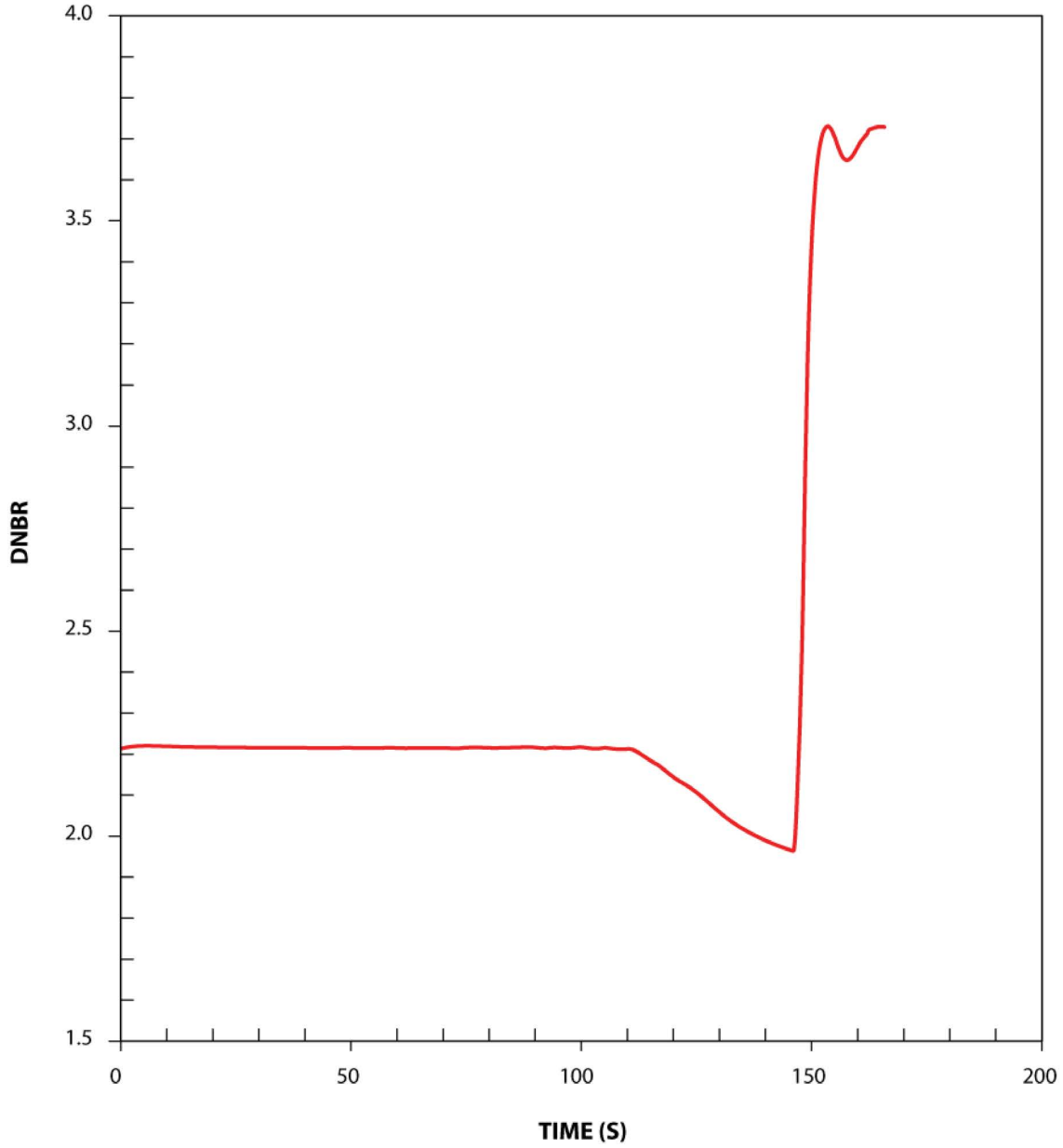
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-5 Feedwater Malfunction – Reduced Feedwater Temperature at HFP Core Average Moderator Temperature vs. Time



Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-6 Feedwater Malfunction – Reduced Feedwater Temperature at HFP Vessel Inlet Temperature vs. Time



Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.1-7 Feedwater Malfunction – Reduced Feedwater Temperature at HFP DNBR vs. Time

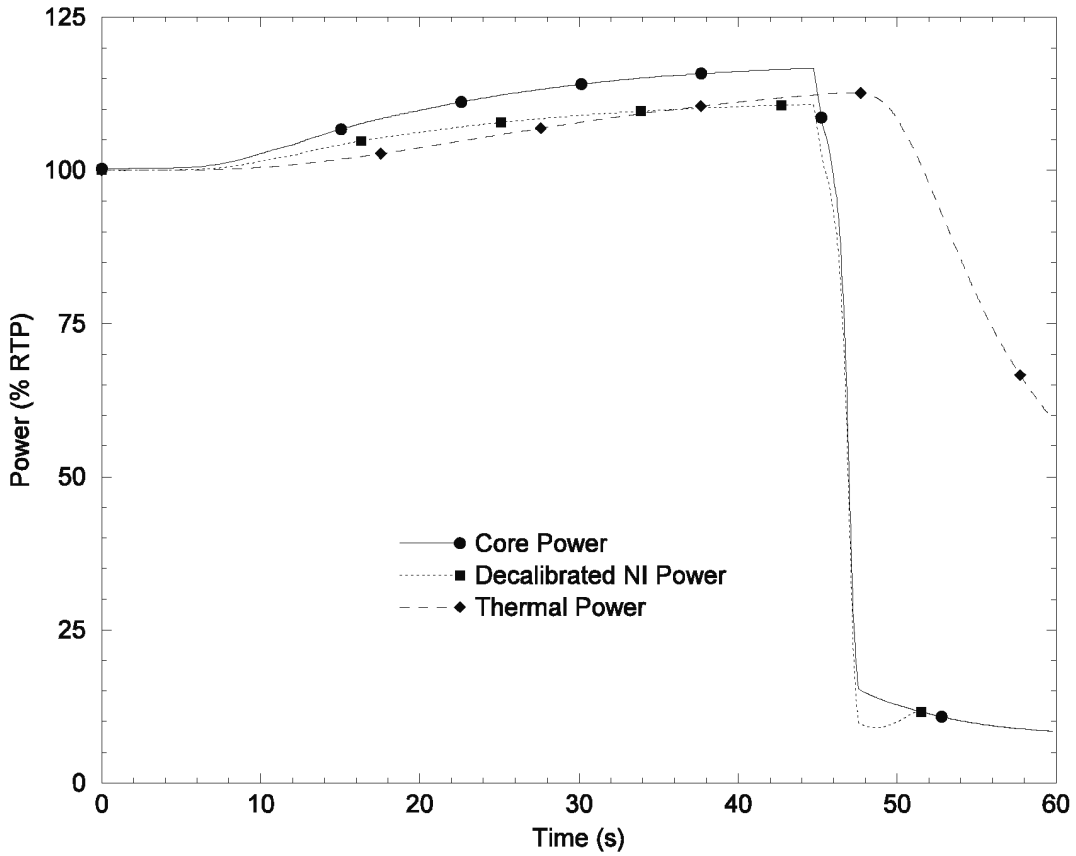


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Figure 15.1.1-8
Reduced Feedwater Temperature (AREVA):
Reactor Power vs. Time

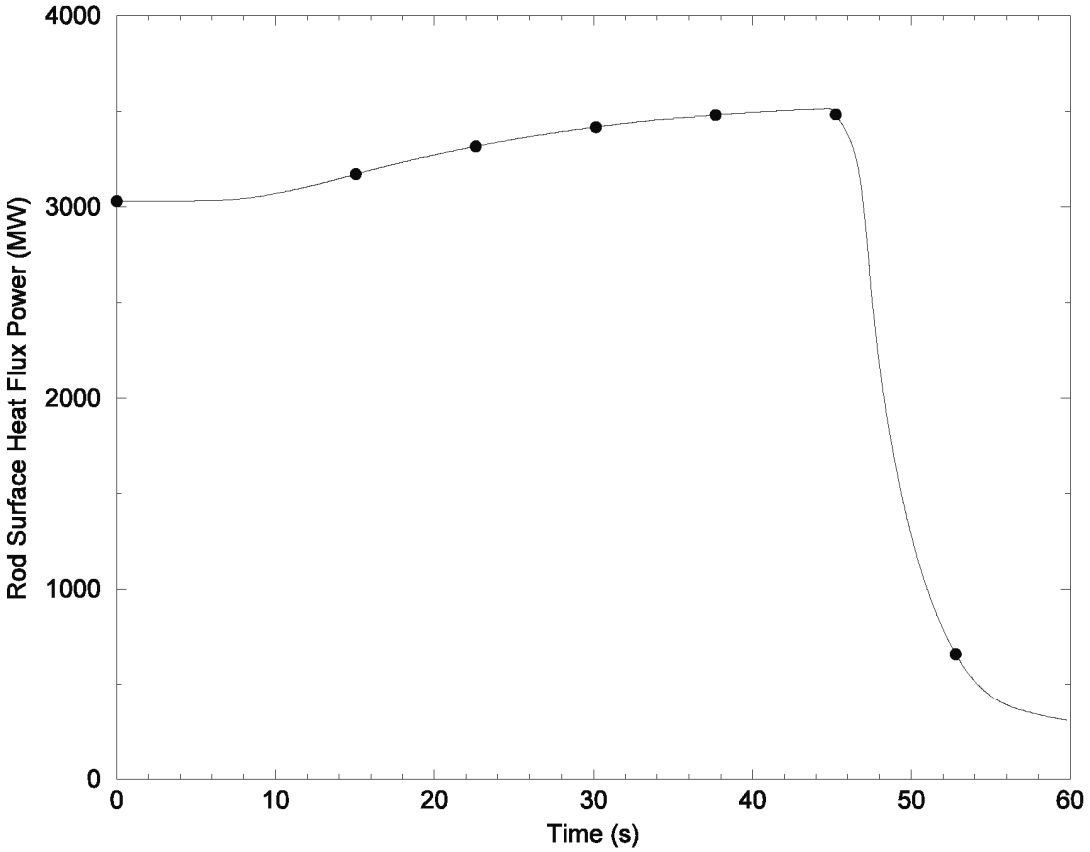

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Figure 15.1.1-9
Reduced Feedwater Temperature (AREVA):
Total Core Heat Flux Power vs. Time

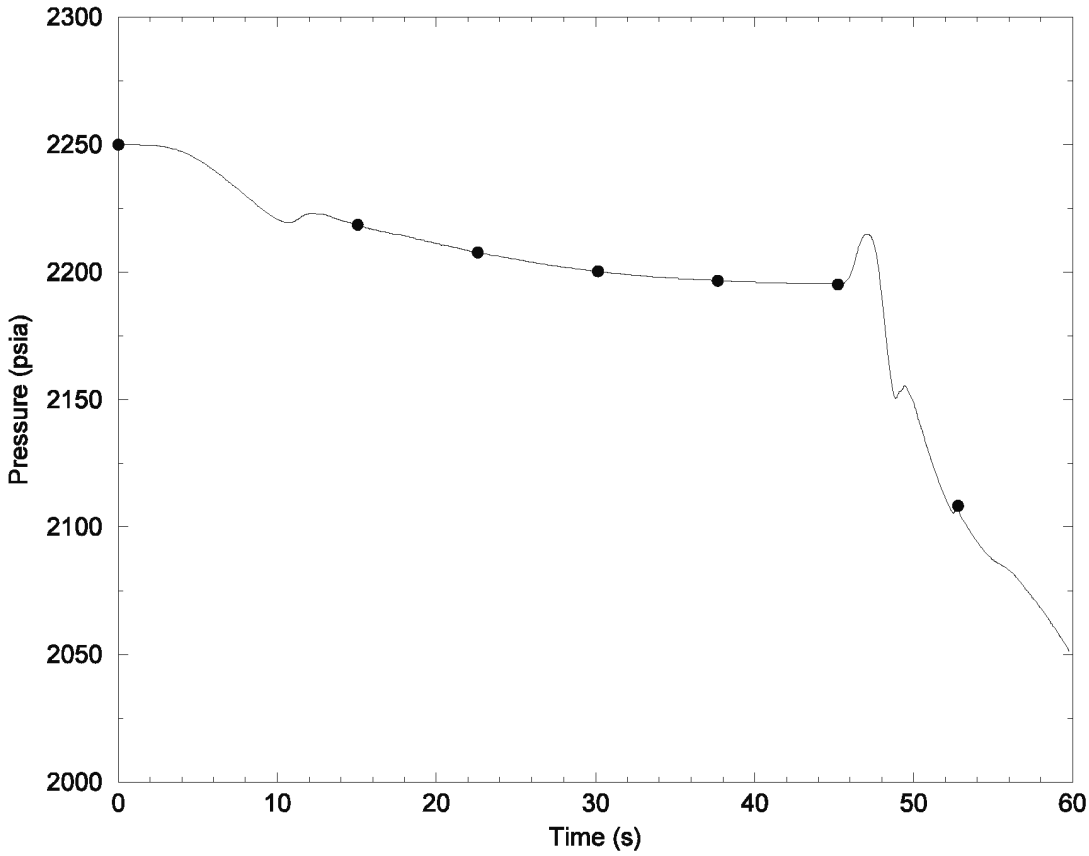

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Figure 15.1.1-10
Reduced Feedwater Temperature (AREVA):
Pressurizer Pressure vs. Time

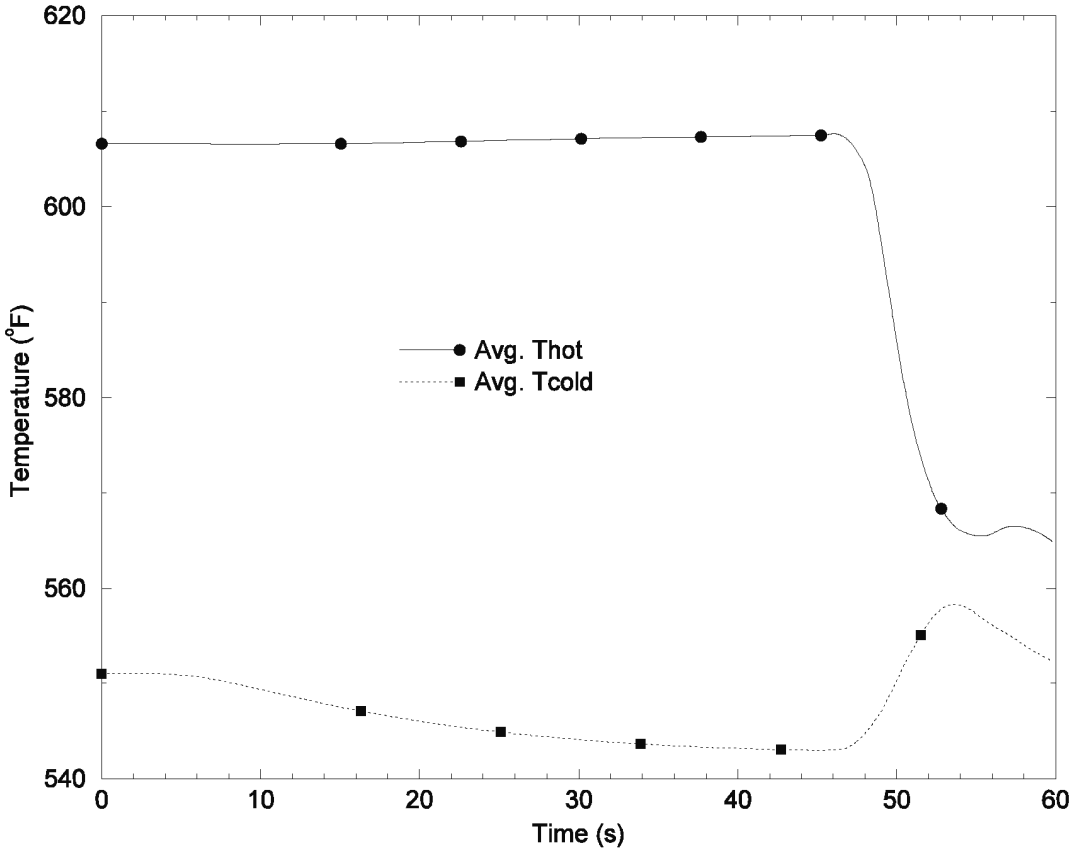

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Figure 15.1.1-11
Reduced Feedwater Temperature (AREVA):
RCS Loop Temperatures vs. Time

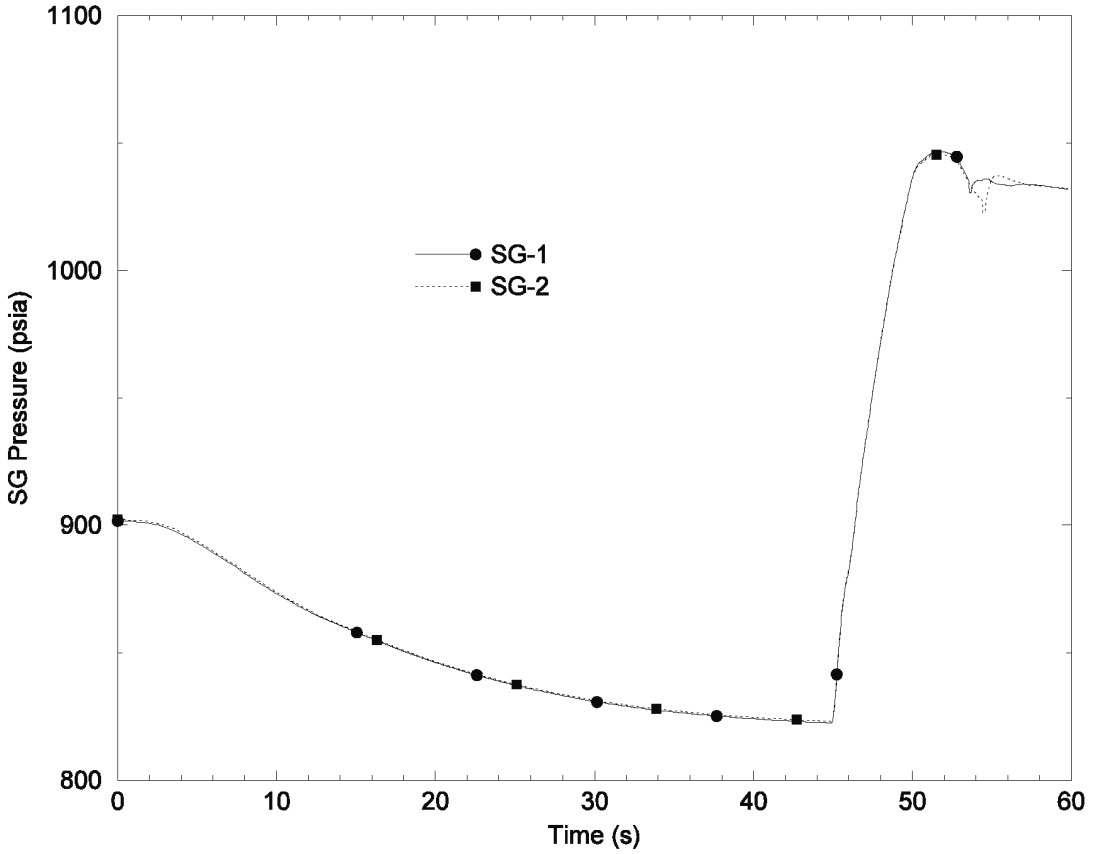

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Figure 15.1.1-12
Reduced Feedwater Temperature (AREVA):
Steam Generator Pressures vs. Time

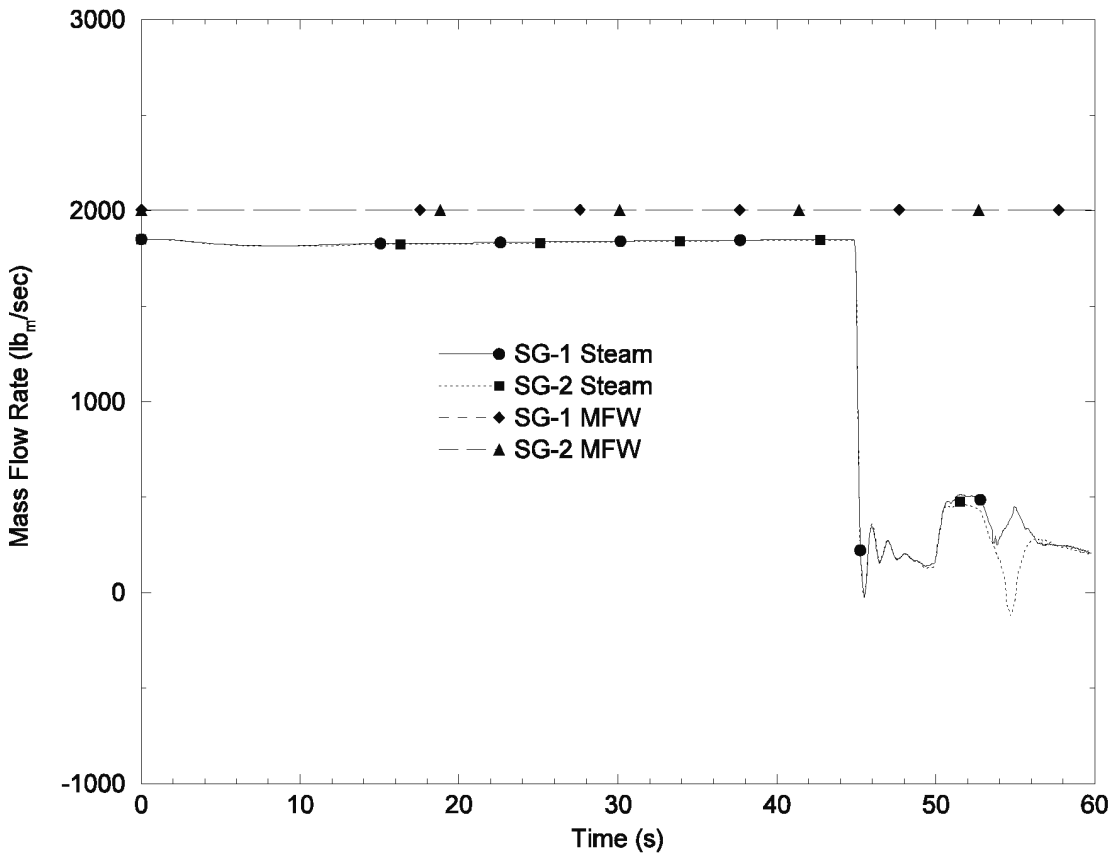

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Figure 15.1.1-13
Reduced Feedwater Temperature (AREVA):
Steam and Feedwater Flow Rates vs. Time

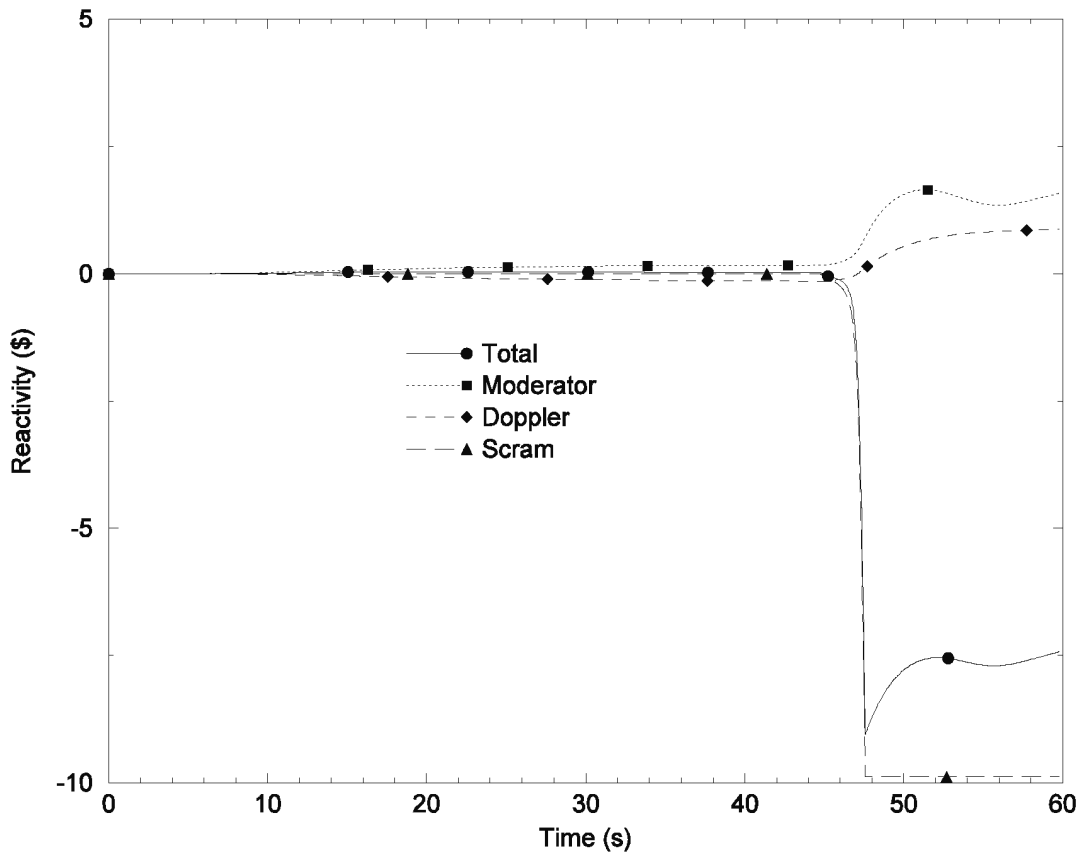

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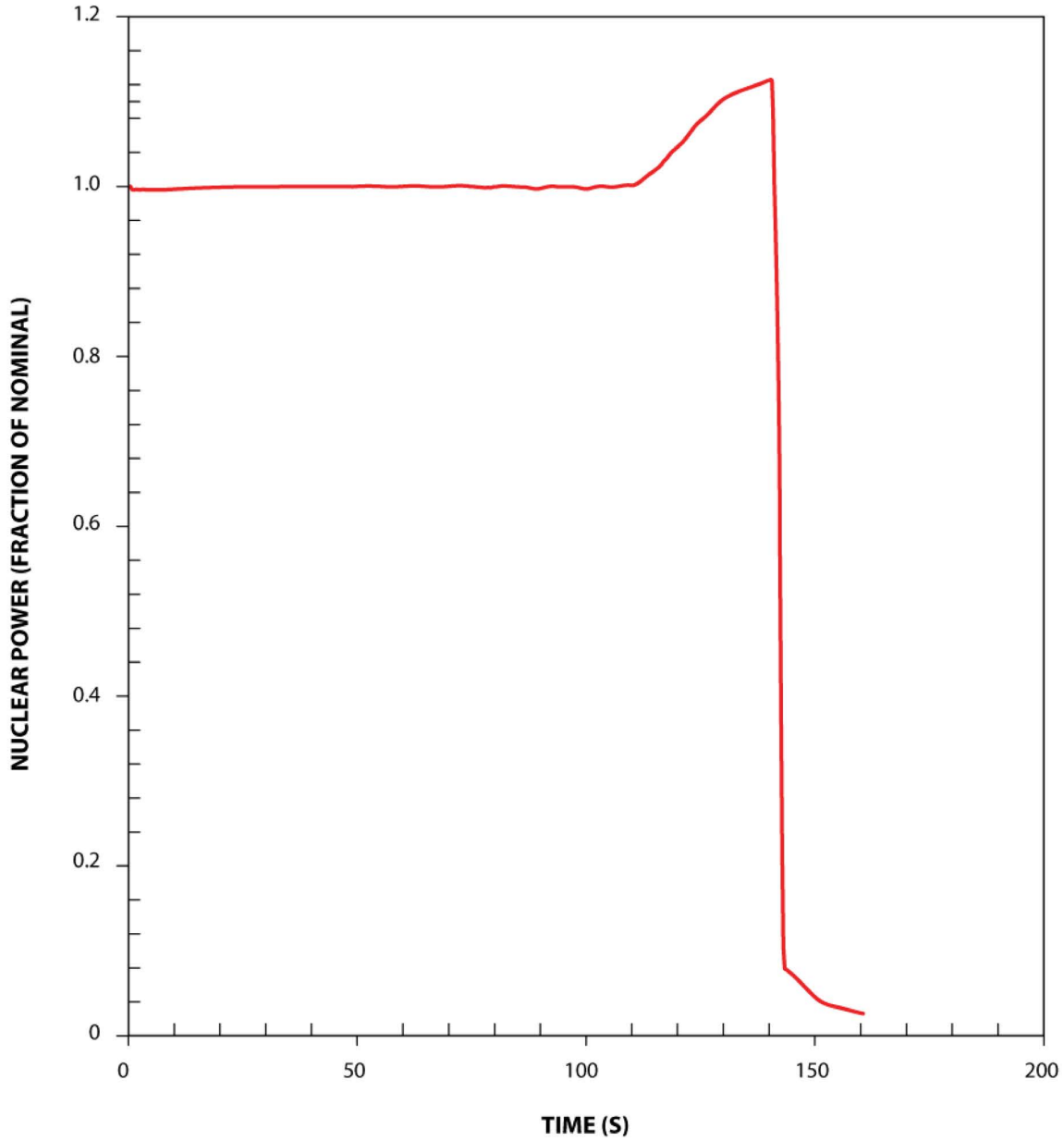
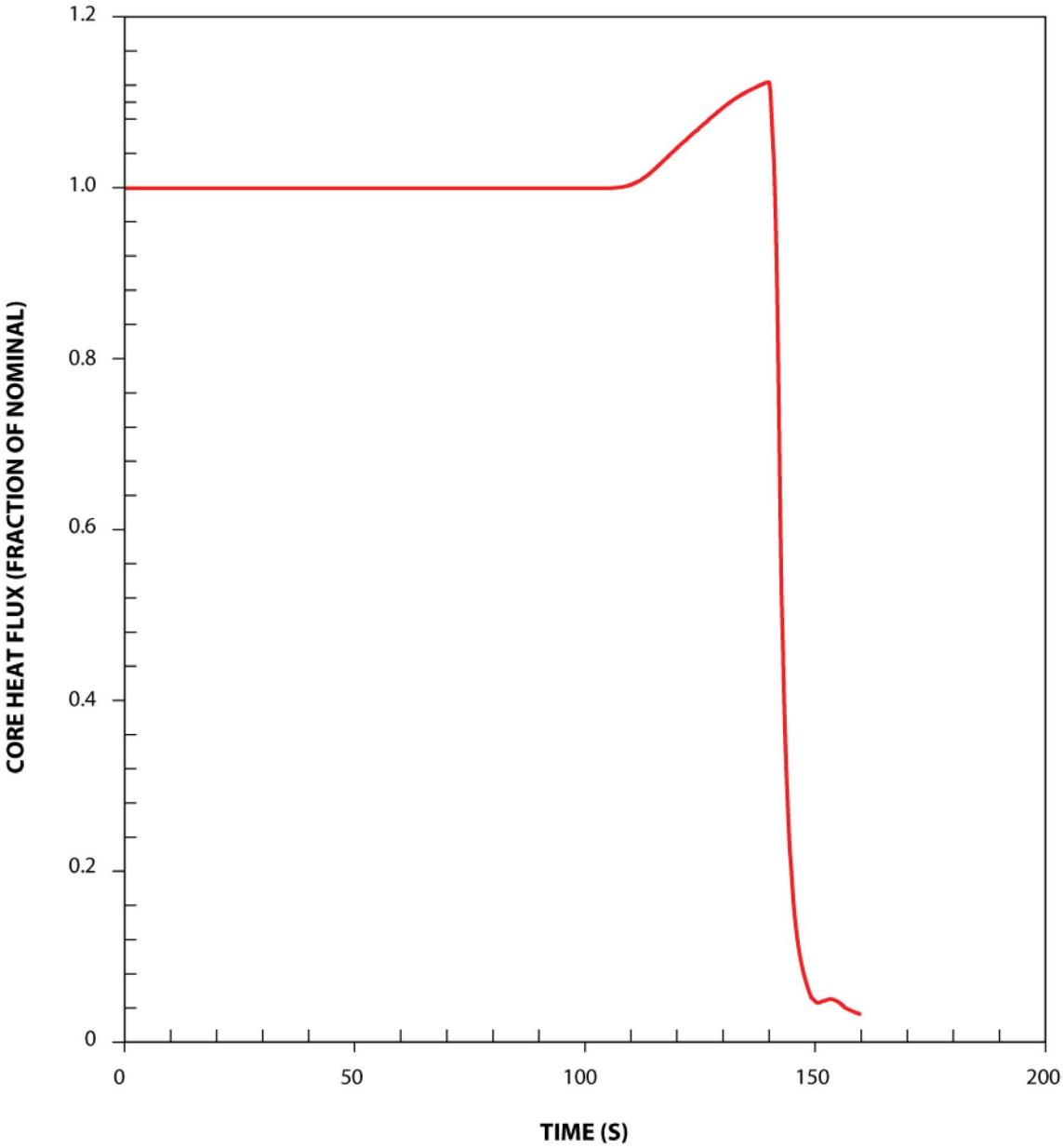
Figure 15.1.1-14
Reduced Feedwater Temperature (AREVA):
Reactivity Feedback vs. Time



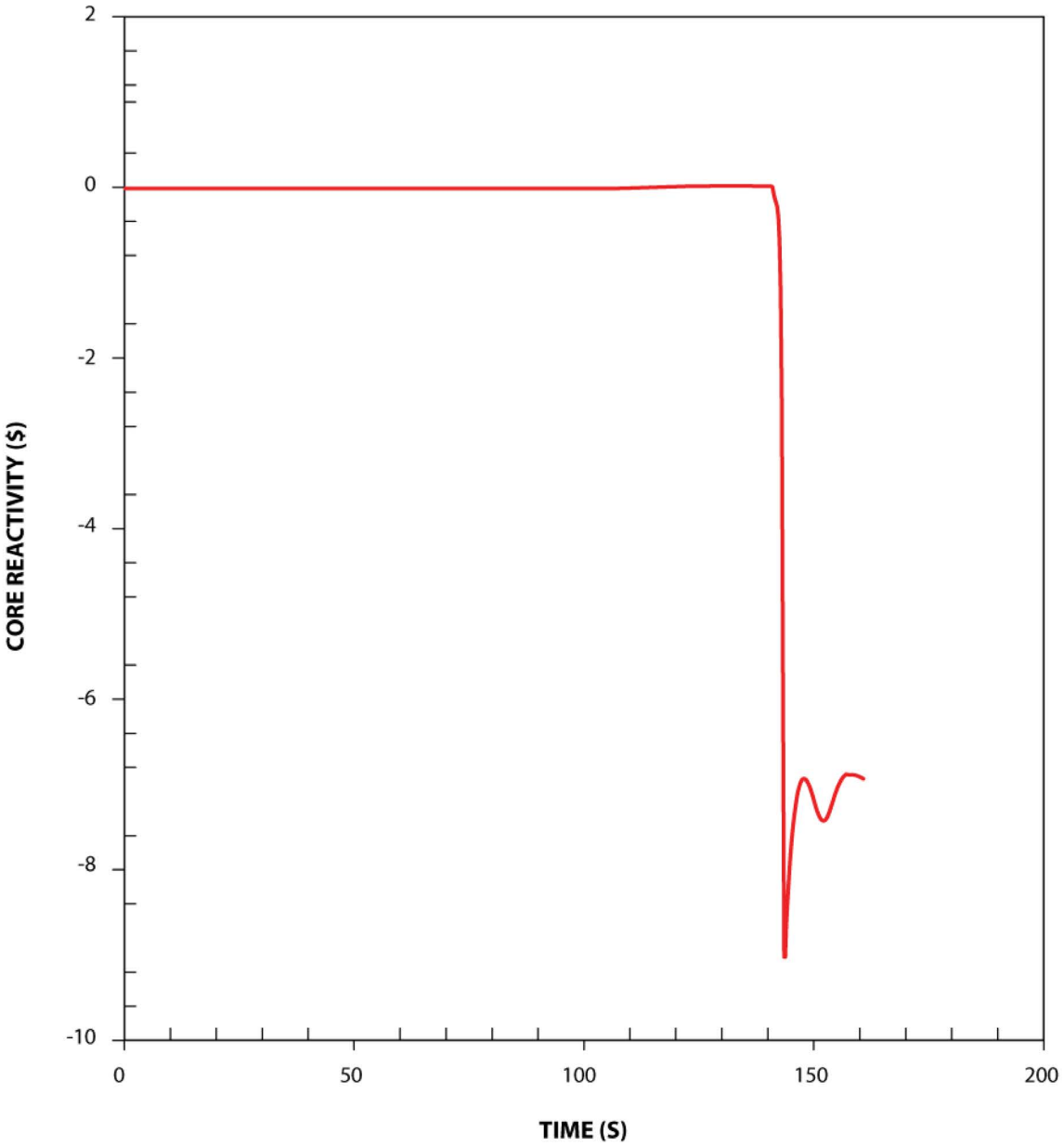
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-1 Feedwater Malfunction - Increased Feedwater Flow at HFP Nuclear Power vs. Time



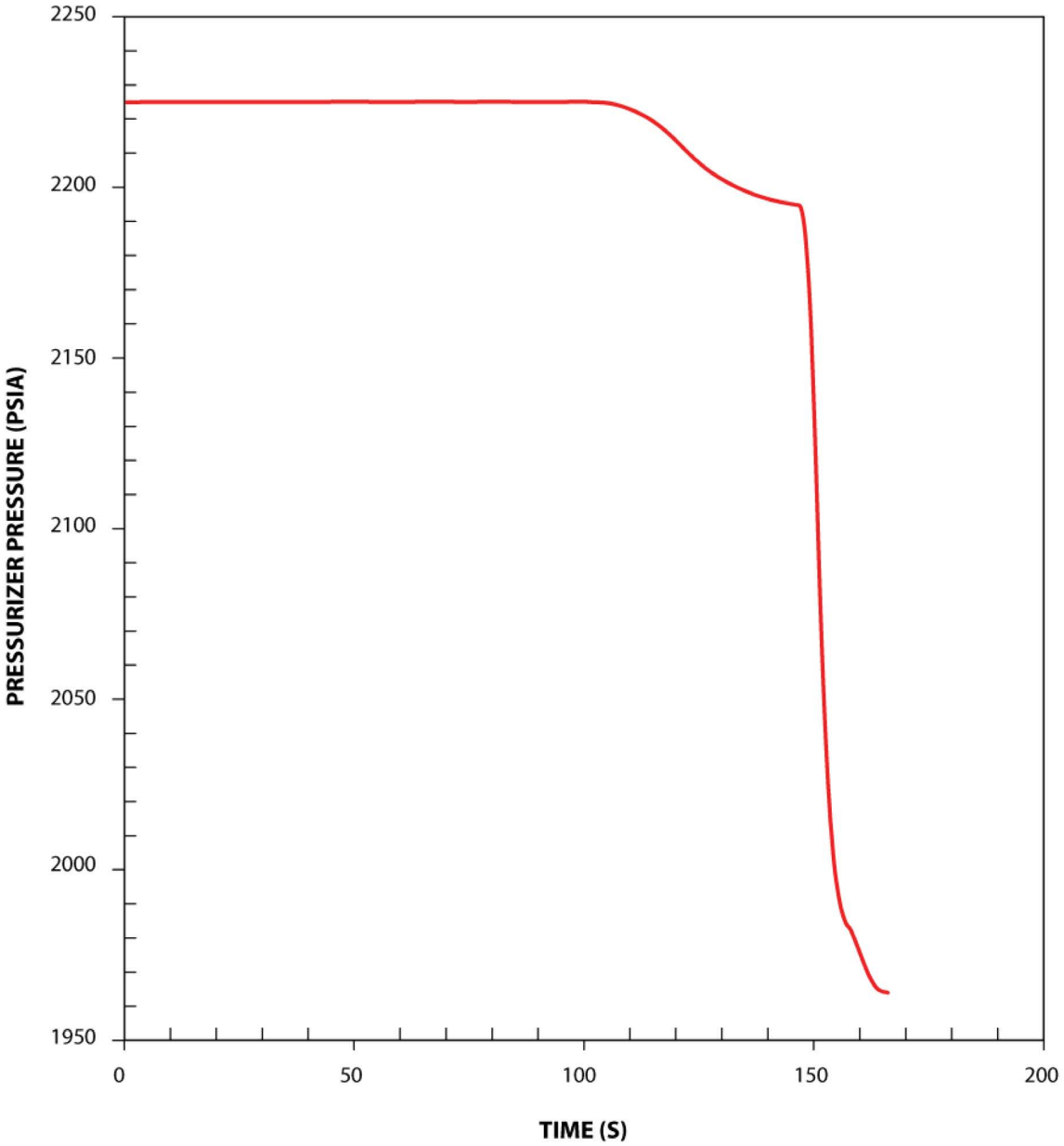
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-2 Feedwater Malfunction - Increased Feedwater Flow at HFP Core Heat Flux vs. Time



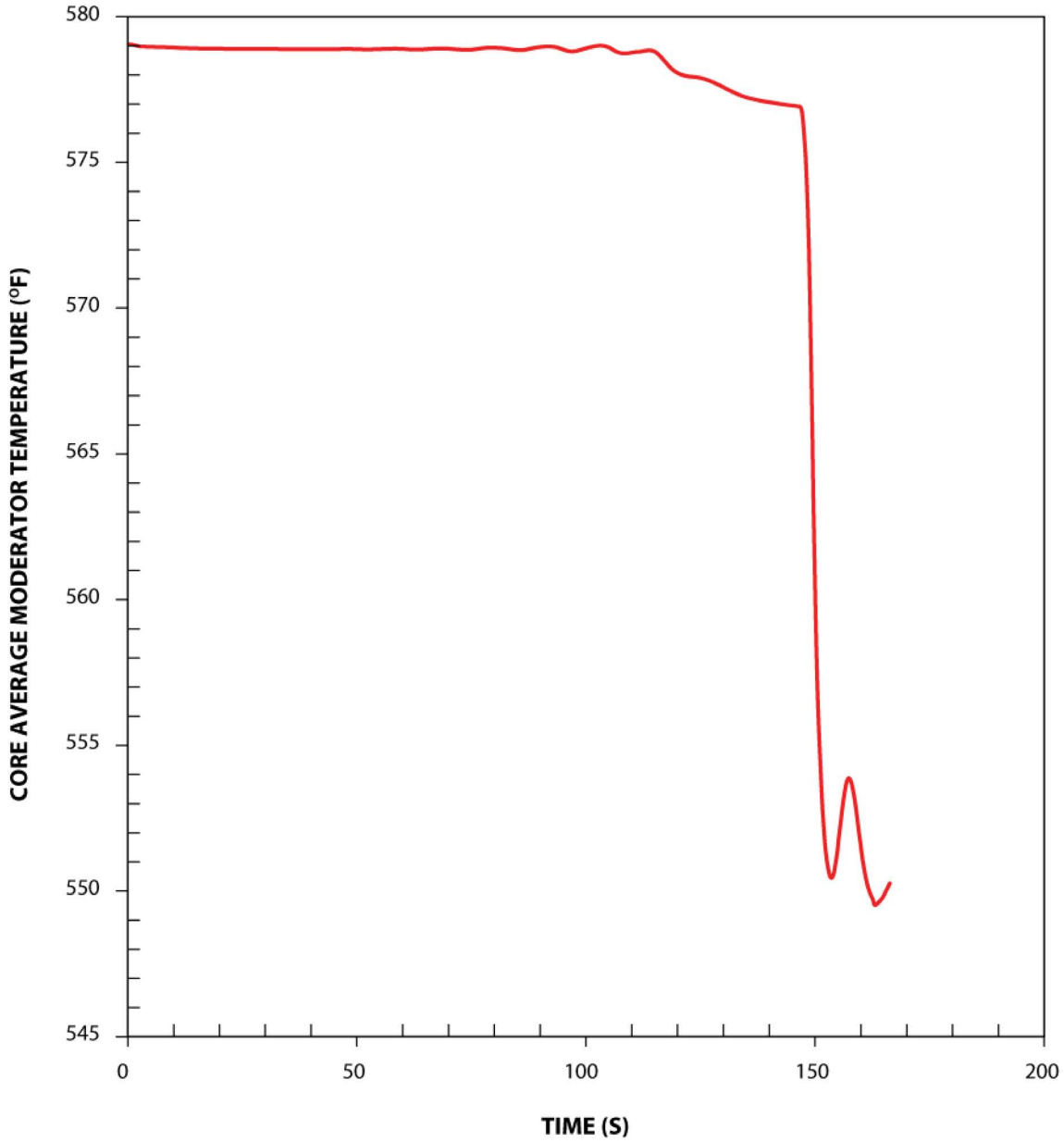
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-3 Feedwater Malfunction - Increased Feedwater Flow at HFP Core Reactivity vs. Time



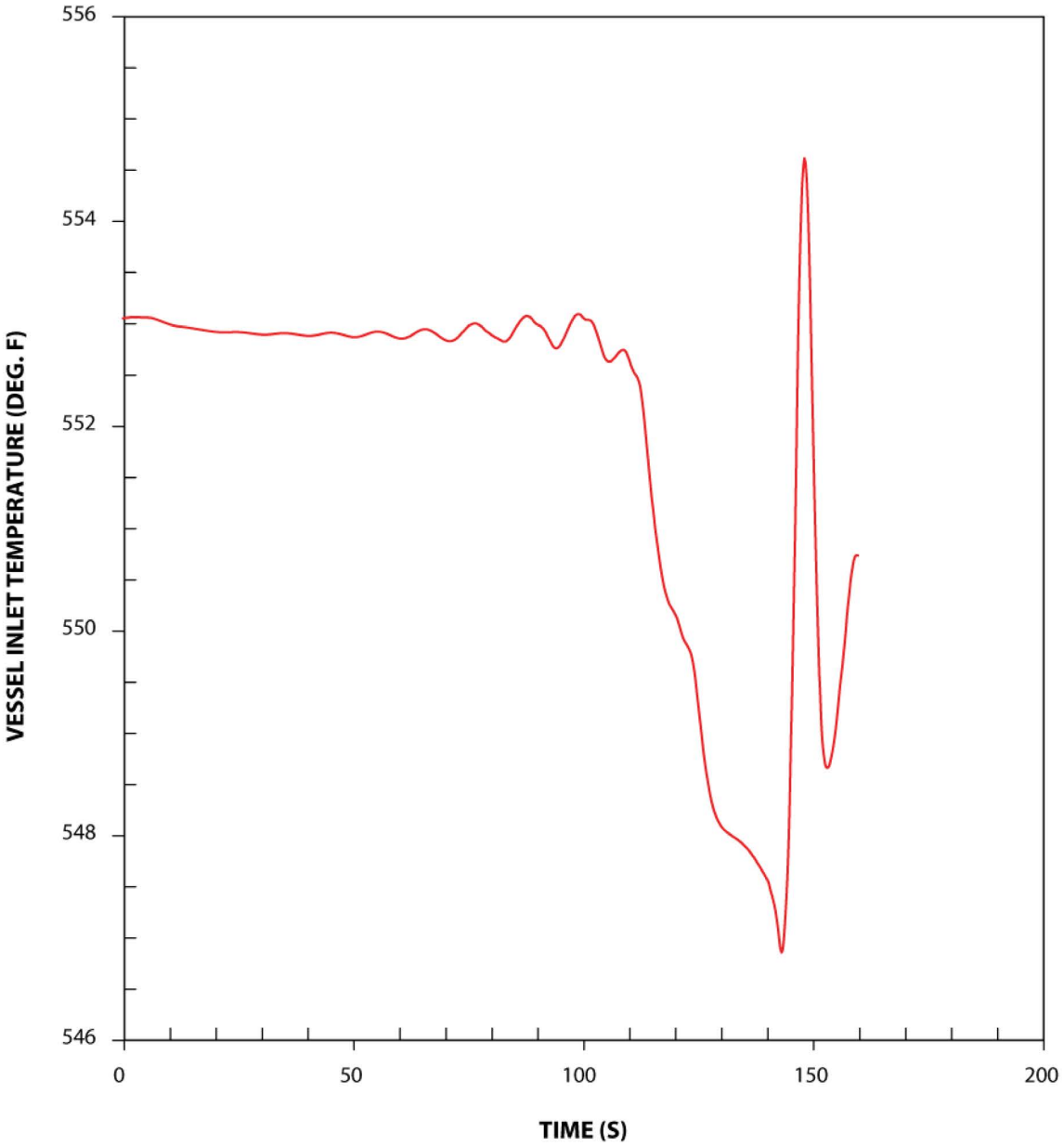
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-4 Feedwater Malfunction - Increased Feedwater Flow at HFP Pressurizer Pressure vs. Time



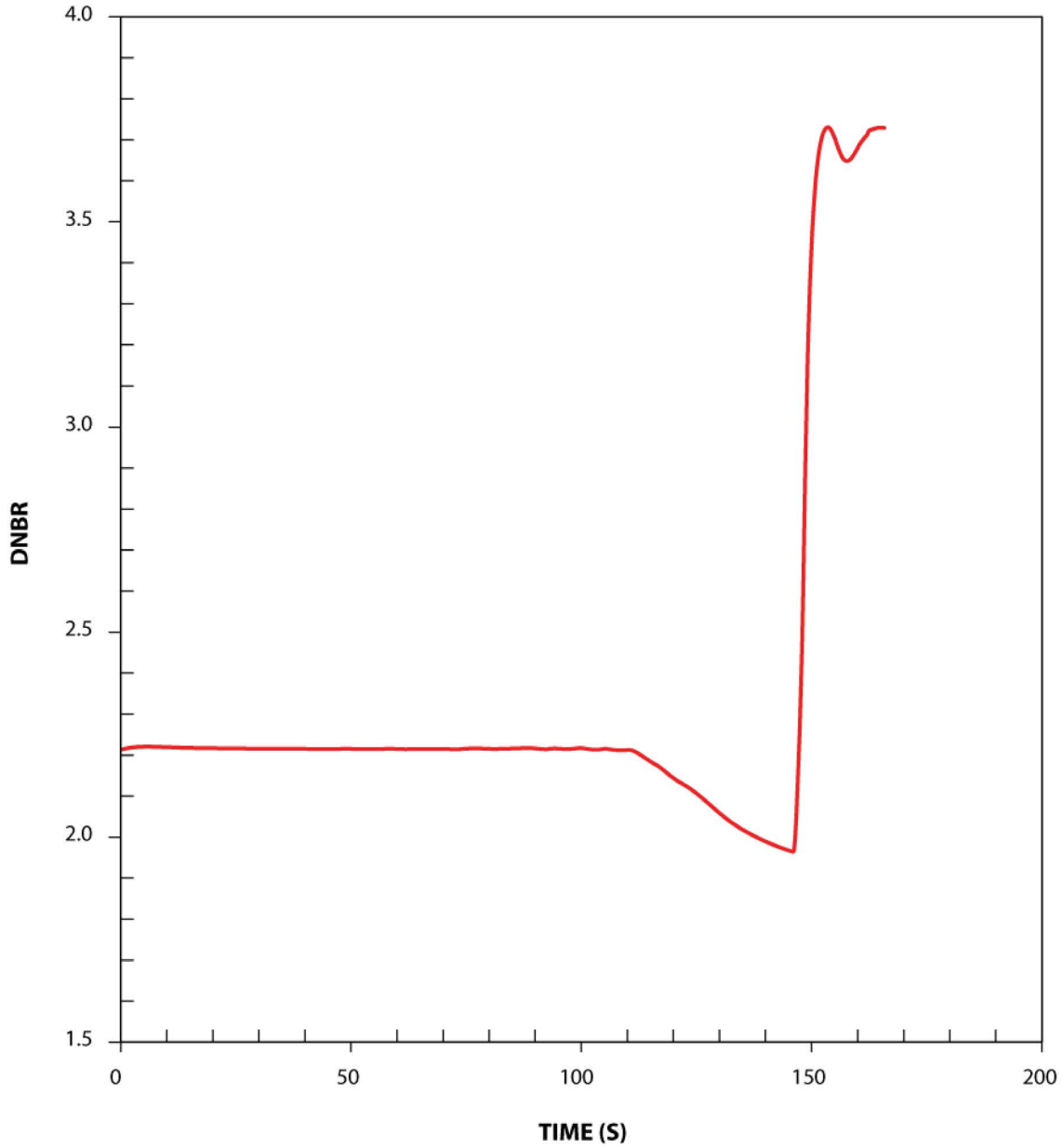
Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-5 Feedwater Malfunction - Increased Feedwater Flow at HFP Core Average Moderator Temperature vs. Time



Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-6 Feedwater Malfunction - Increased Feedwater Flow at HFP Vessel Inlet Temperature vs. Time



Note: Figure includes a 100 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.2-7 Feedwater Malfunction - Increased Feedwater Flow at HFP DNBR vs. Time

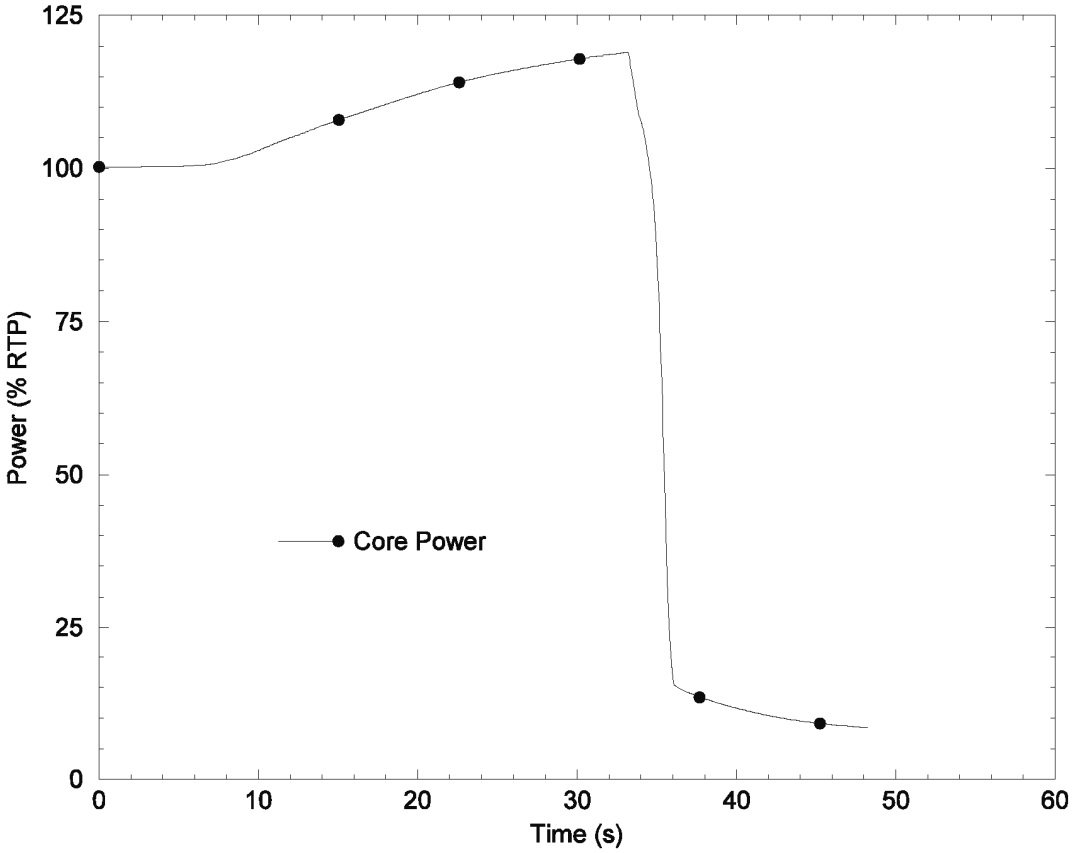


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Figure 15.1.2-8
Increased Feedwater Flow, HFP (AREVA):
Reactor Power vs. Time

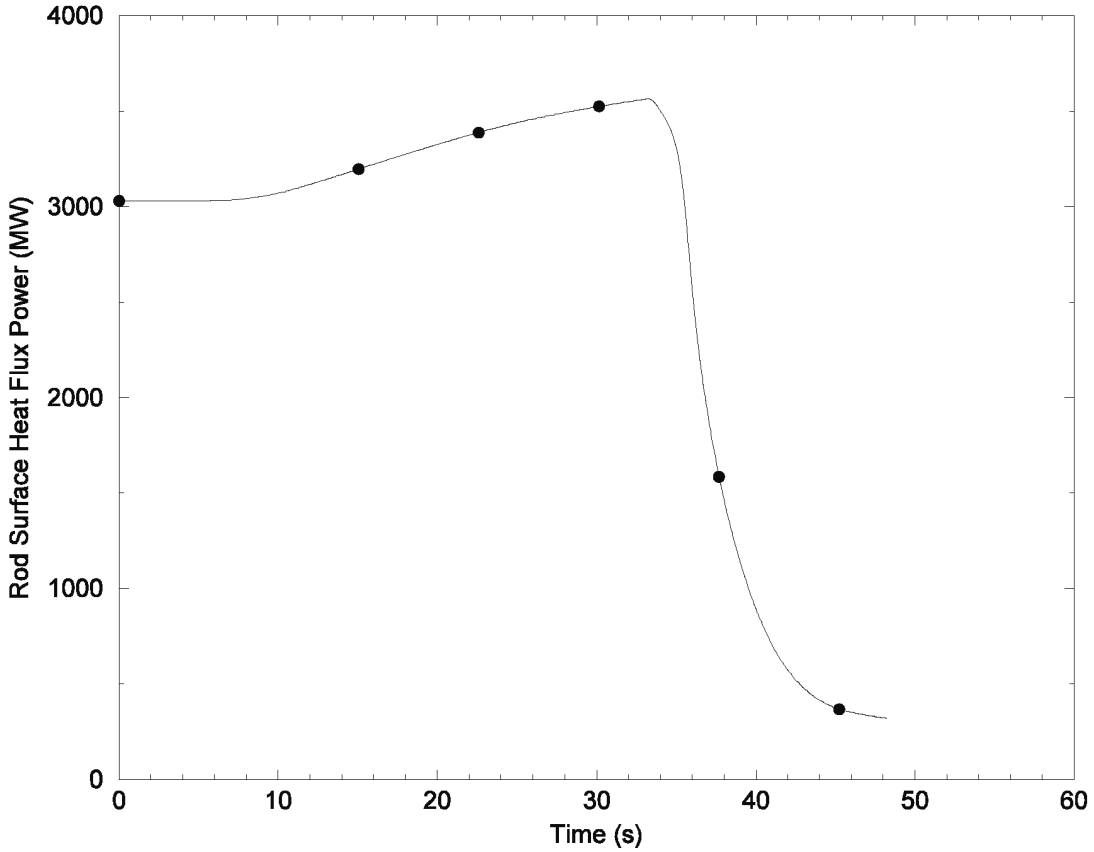

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Figure 15.1.2-9
Increased Feedwater Flow, HFP (AREVA):
Total Core Heat Flux Power vs. Time

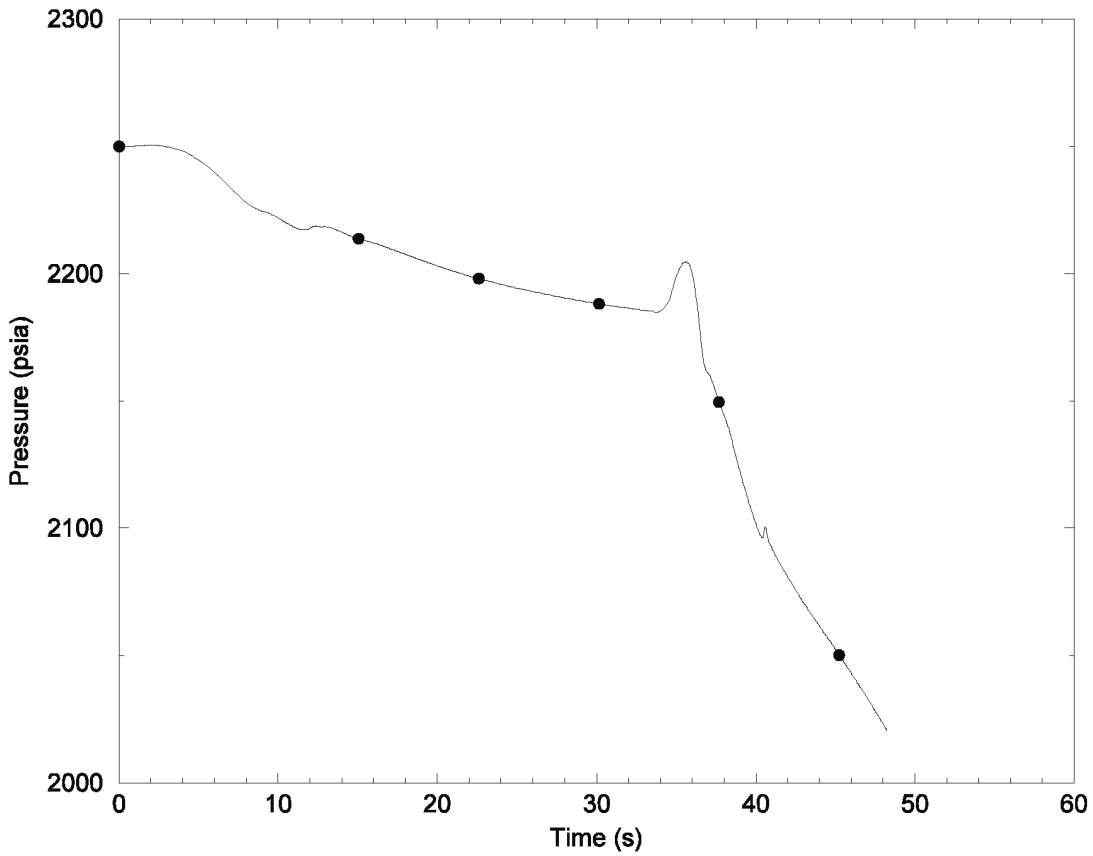

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Figure 15.1.2-10
Increased Feedwater Flow, HFP (AREVA):
Pressurizer Pressure vs. Time

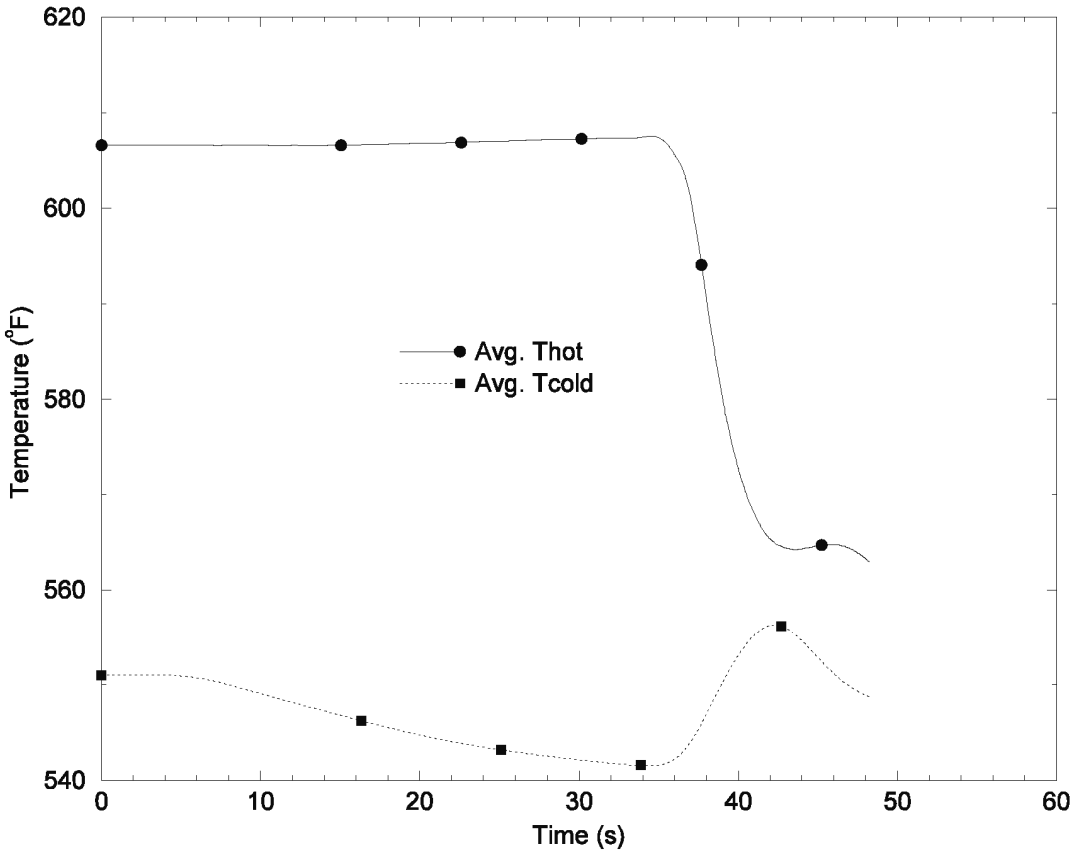

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Figure 15.1.2-11
Increased Feedwater Flow, HFP (AREVA):
RCS Loop Temperatures vs. Time

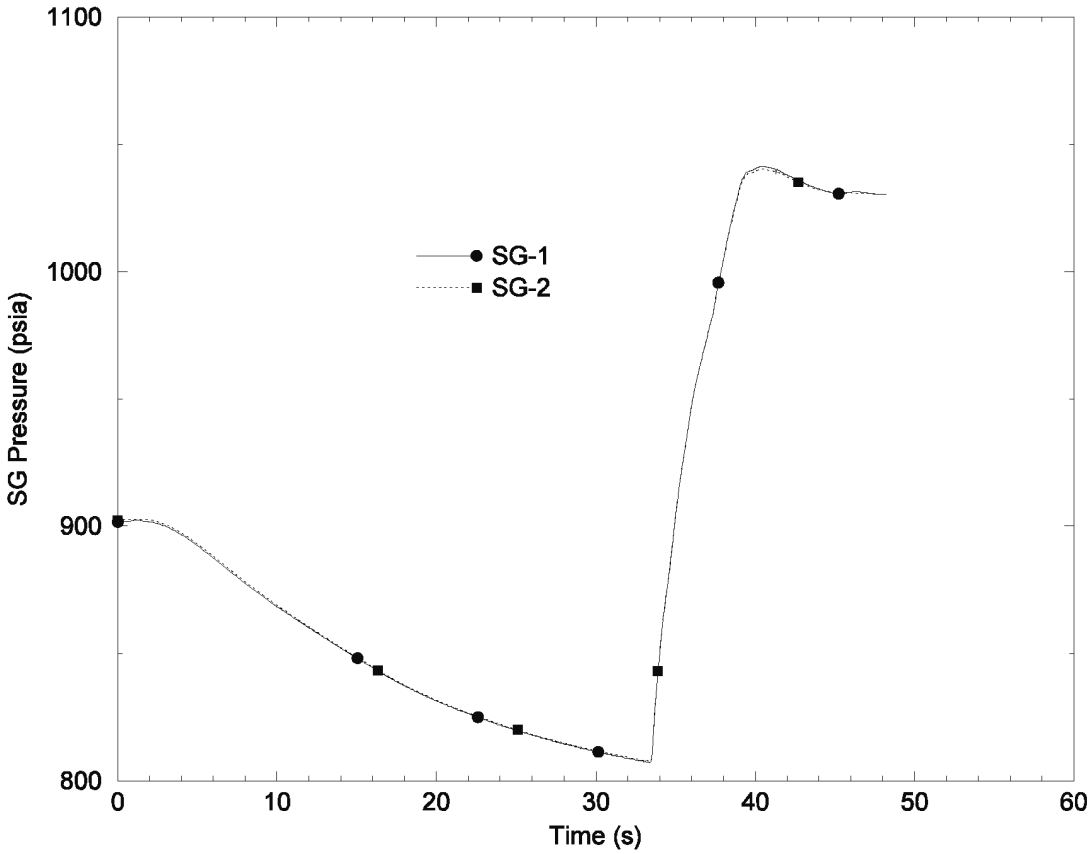

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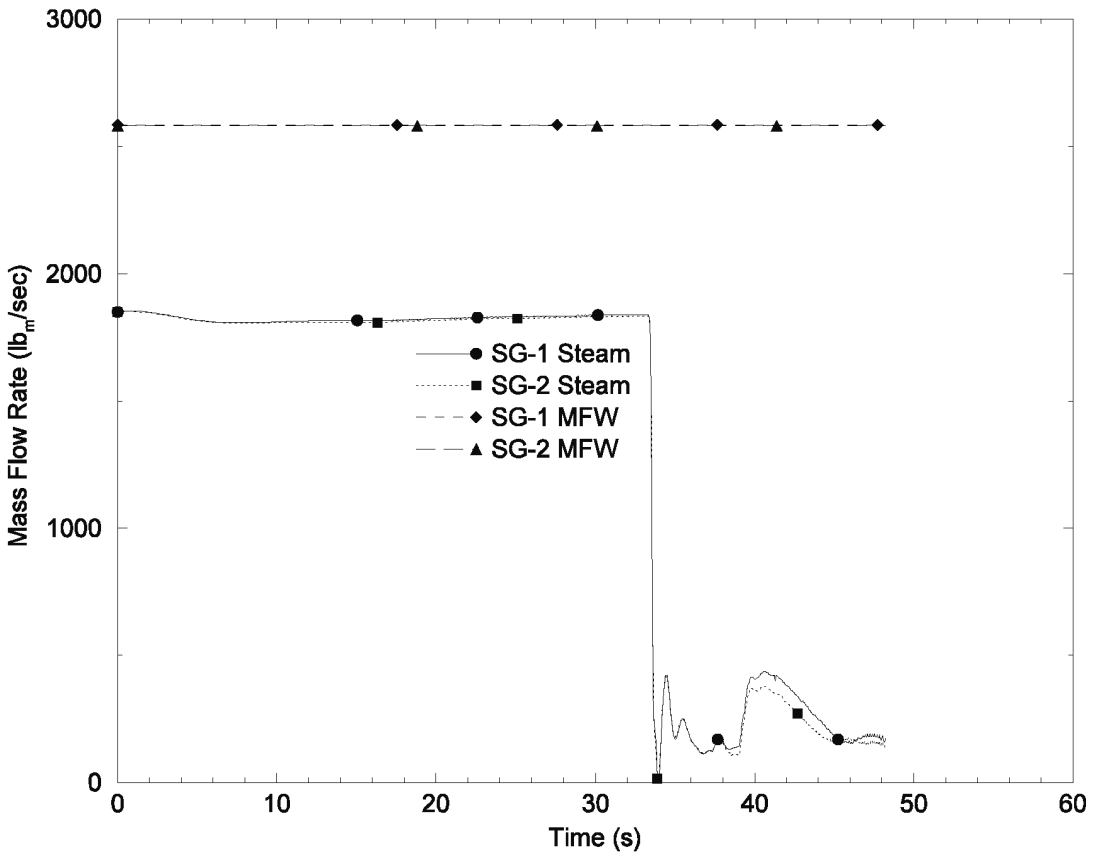
Figure 15.1.2-12
Increased Feedwater Flow, HFP (AREVA):
Steam Generator Pressures vs. Time



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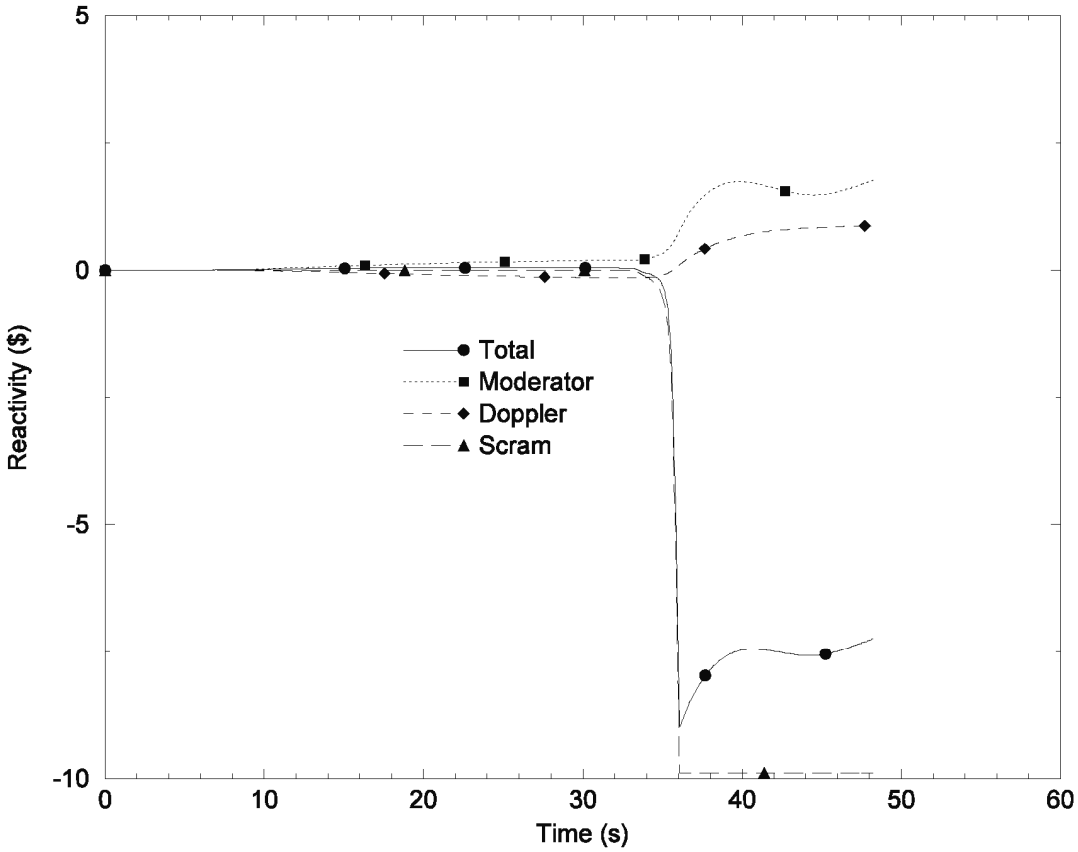
ST. LUCIE PLANT UNIT 2

Figure 15.1.2-13
Increased Feedwater Flow, HFP (AREVA):
Steam and Feedwater Flow Rates vs. Time



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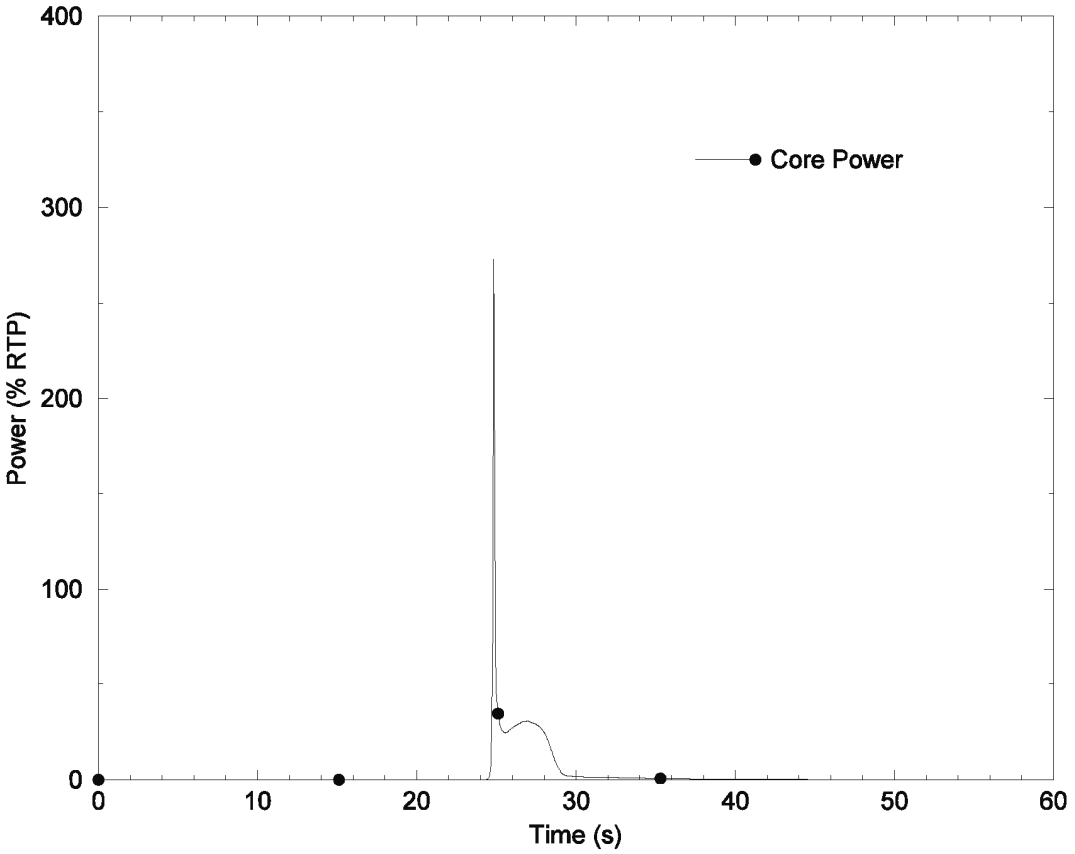
ST. LUCIE PLANT UNIT 2

Figure 15.1.2-14
Increased Feedwater Flow, HFP (AREVA):
Reactivity Feedback vs. Time



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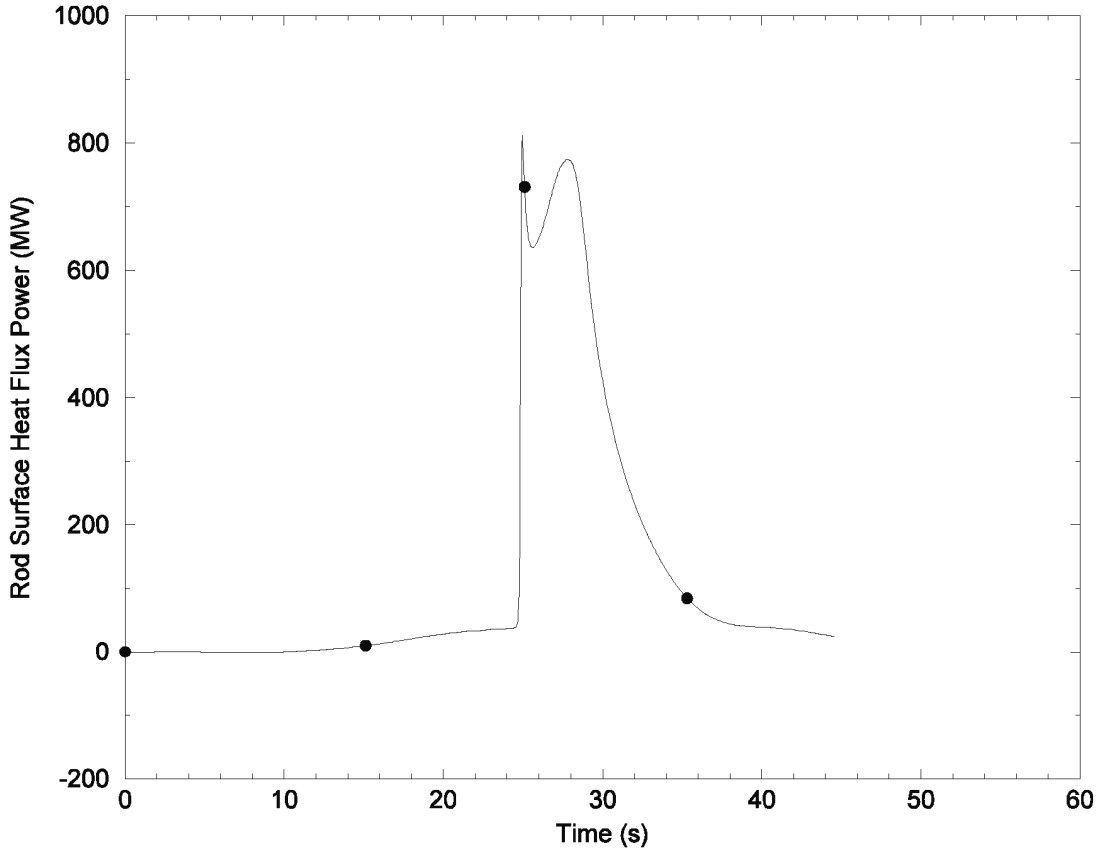
ST. LUCIE PLANT UNIT 2

Figure 15.1.2-15
Increased Feedwater Flow, HZP (AREVA):
Reactor Power vs. Time



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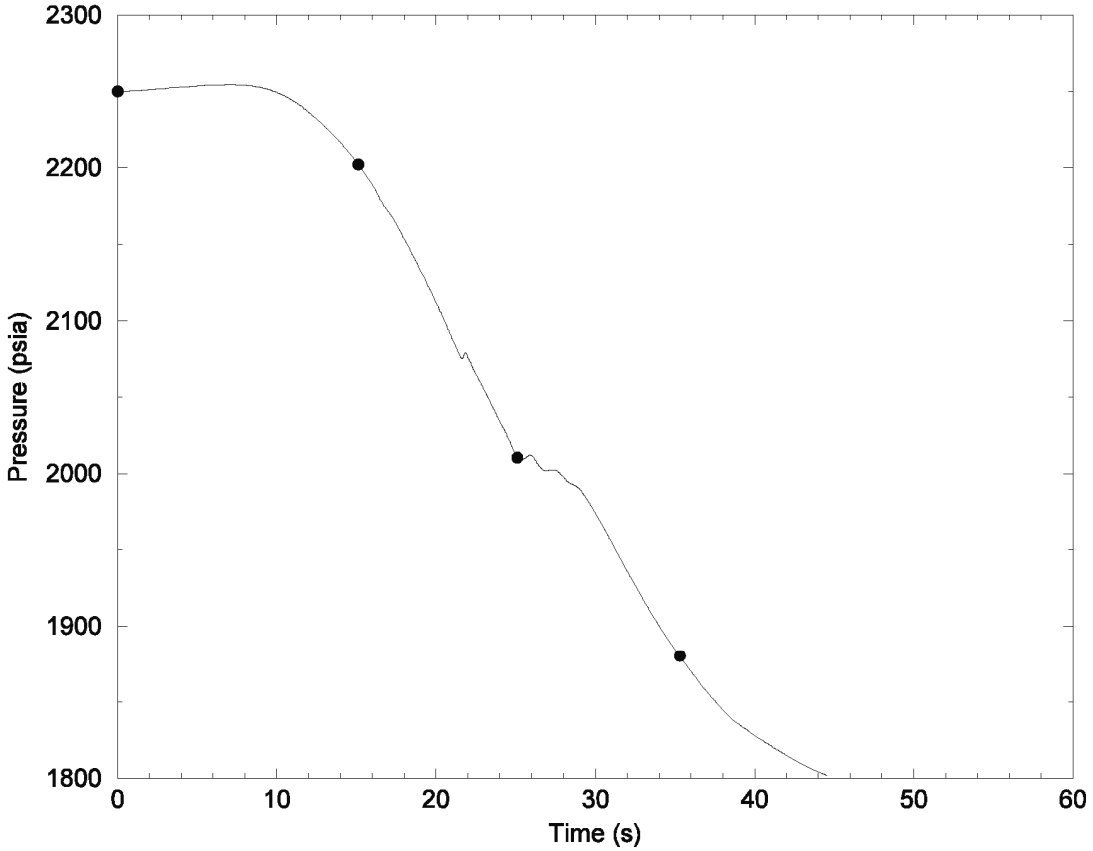
ST. LUCIE PLANT UNIT 2

Figure 15.1.2-16
Increased Feedwater Flow, HZP (AREVA):
Total Core Heat Flux Power vs. Time



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ST. LUCIE PLANT UNIT 2

Figure 15.1.2-17
Increased Feedwater Flow, HZP (AREVA):
Pressurizer Pressure vs. Time

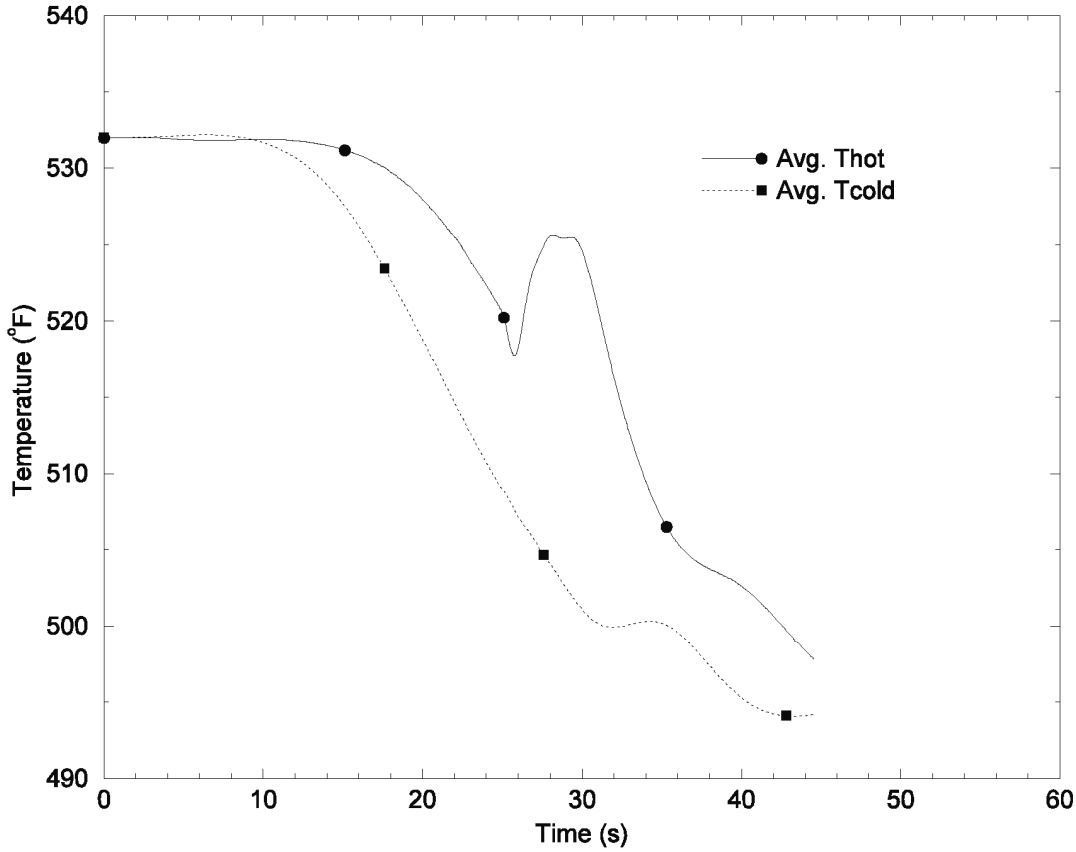

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Figure 15.1.2-18
Increased Feedwater Flow, HZP (AREVA):
RCS Loop Temperatures vs. Time

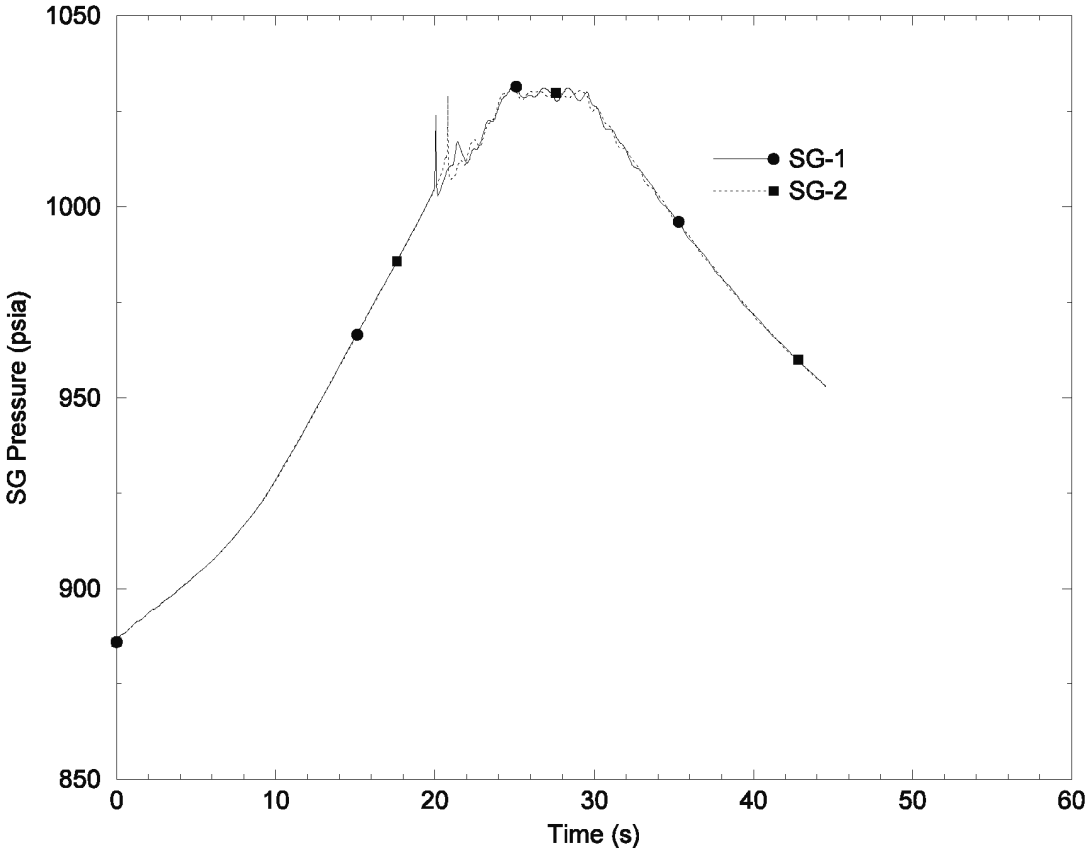

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Figure 15.1.2-19
Increased Feedwater Flow, HZP (AREVA):
Steam Generator Pressures vs. Time

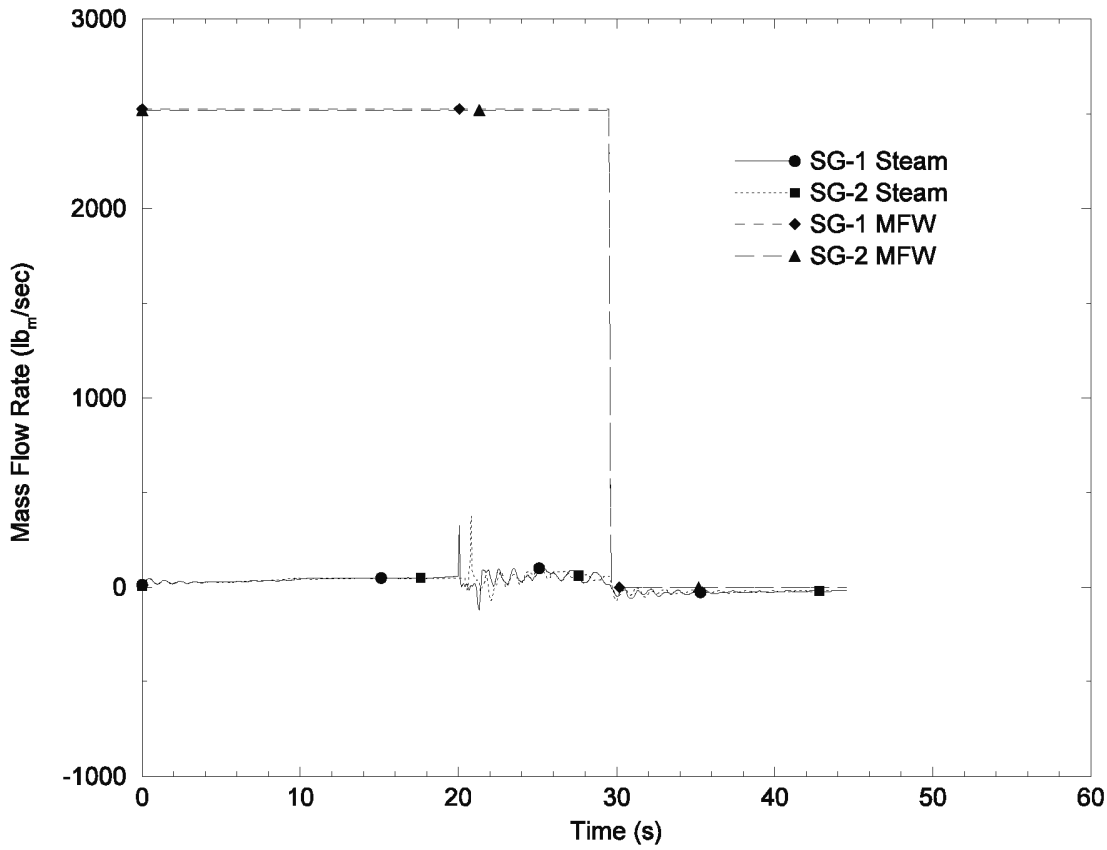

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Figure 15.1.2-20
Increased Feedwater Flow, HZP (AREVA):
Steam and Feedwater Flow Rates vs. Time

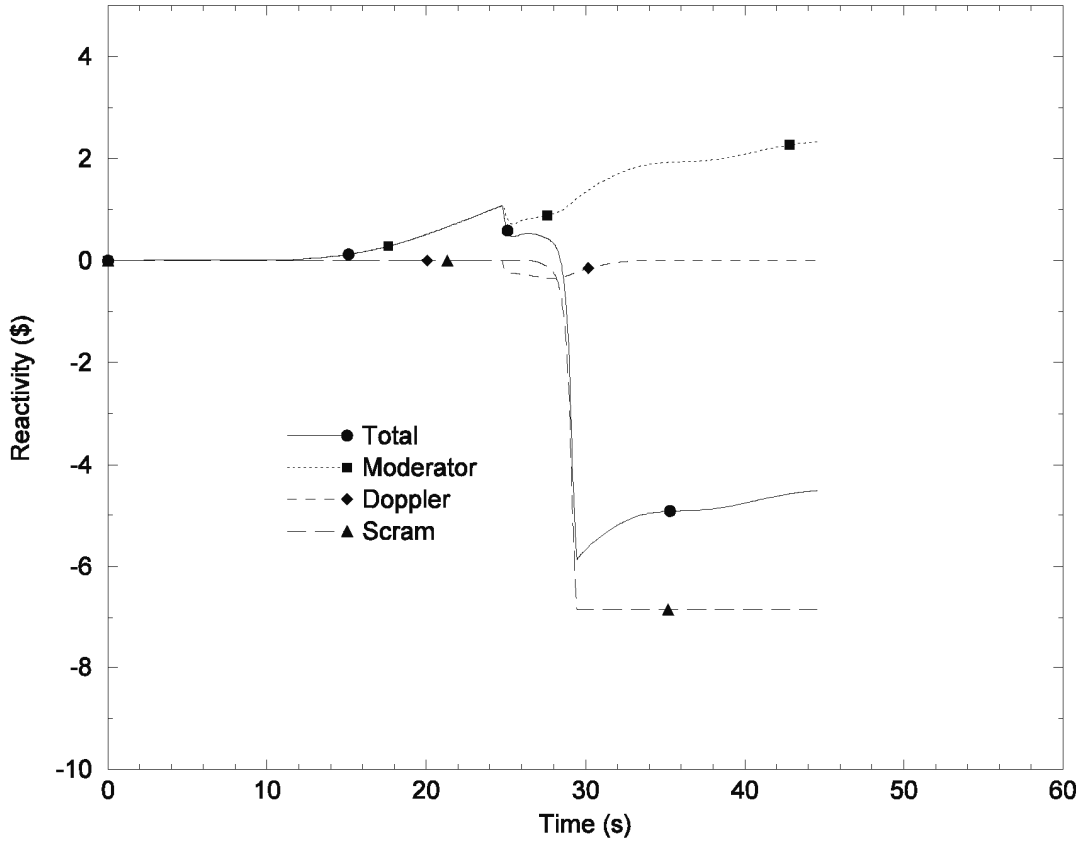

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Figure 15.1.2-21
Increased Feedwater Flow, HZP (AREVA):
Reactivity Feedback vs. Time

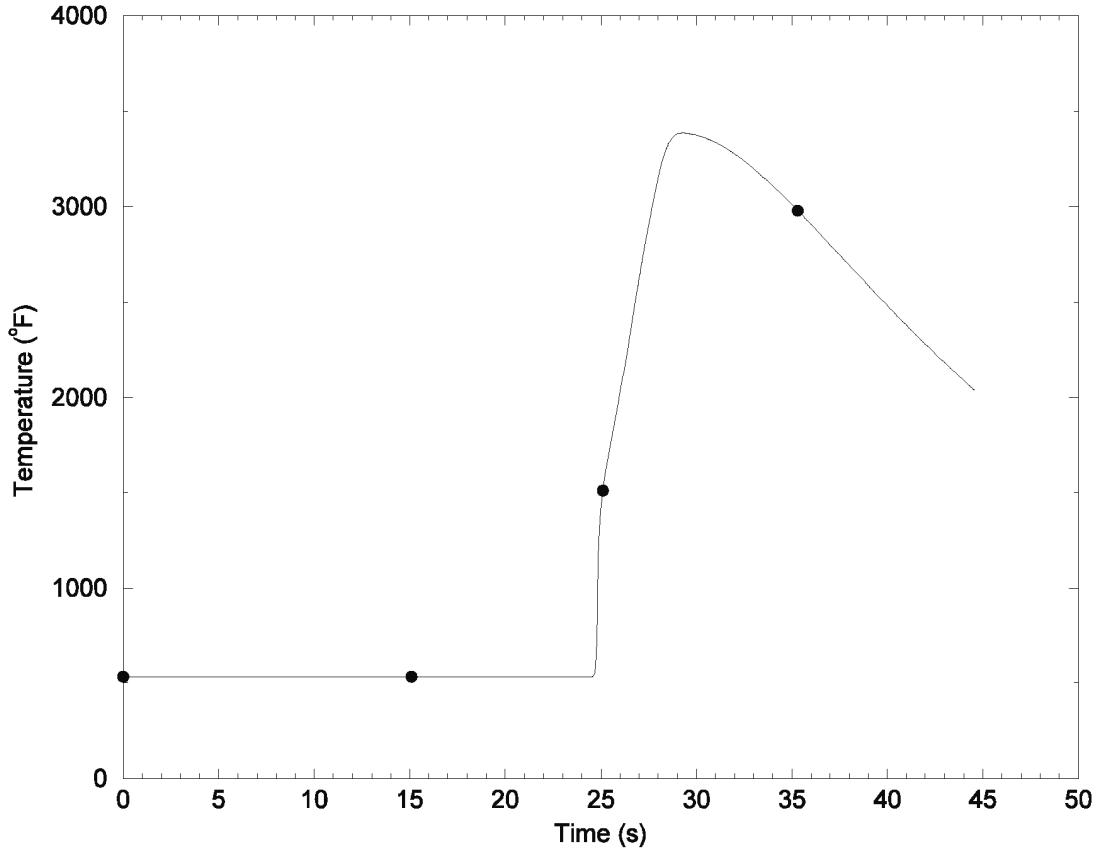

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Figure 15.1.2-22
Increased Feedwater Flow, HZP (AREVA):
Peak Fuel Centerline Temperature vs. Time

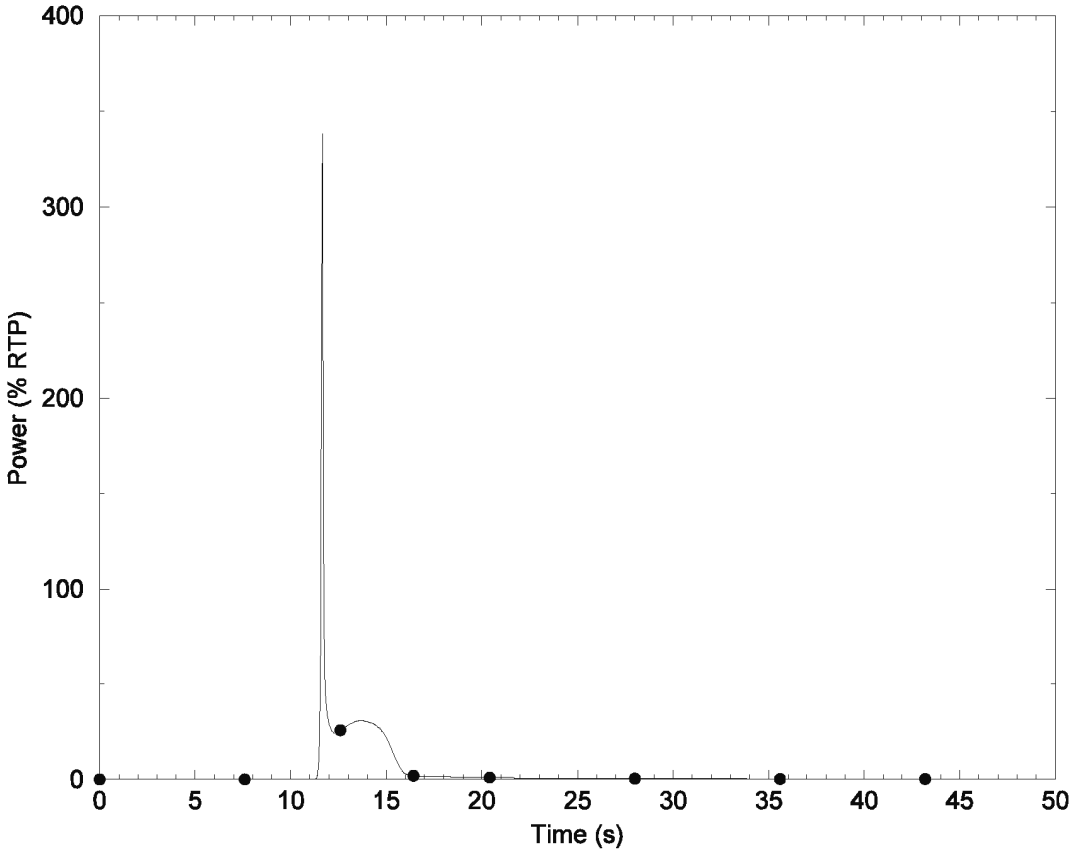

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Figure 15.1.3-1
Increased Steam Flow, HZP (AREVA):
Reactor Power vs. Time

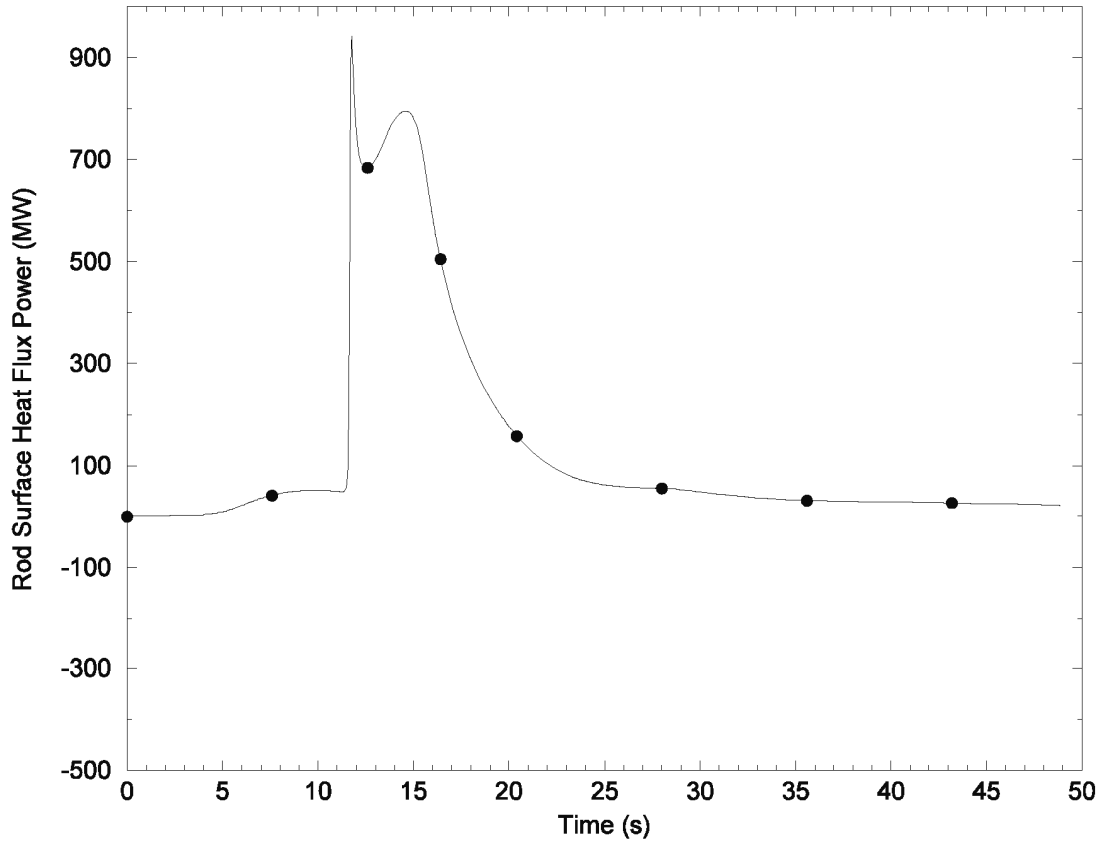

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Figure 15.1.3-2
Increased Steam Flow, HZP (AREVA):
Total Core Heat Flux Power vs. Time

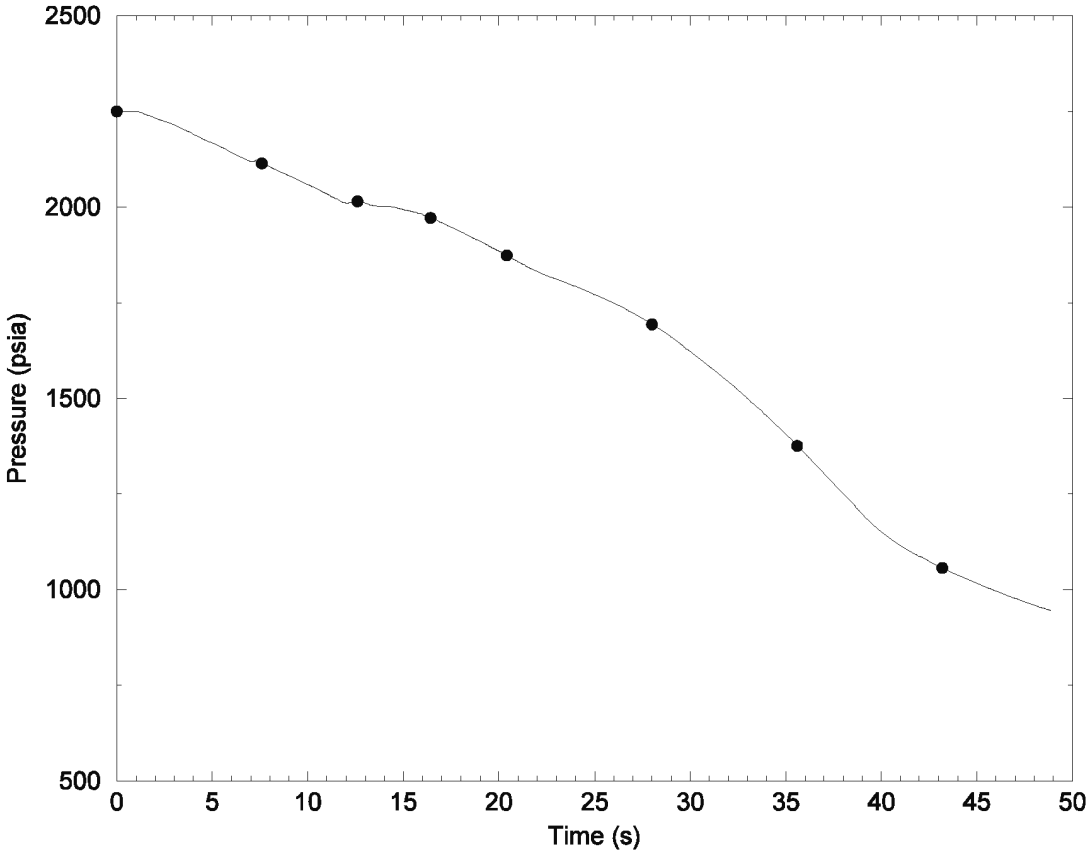

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Figure 15.1.3-3
Increased Steam Flow, HZP (AREVA):
Pressurizer Pressure vs. Time

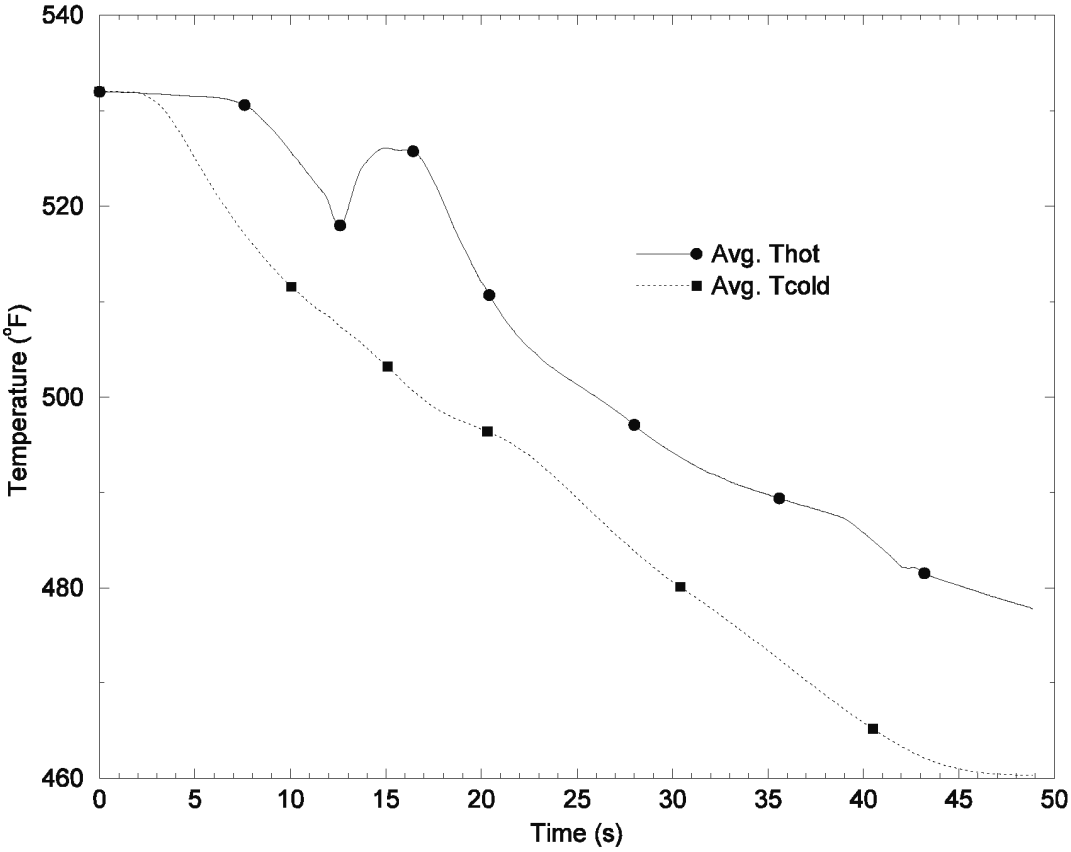

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Figure 15.1.3-4
Increased Steam Flow, HZP (AREVA):
RCS Loop Temperatures vs. Time

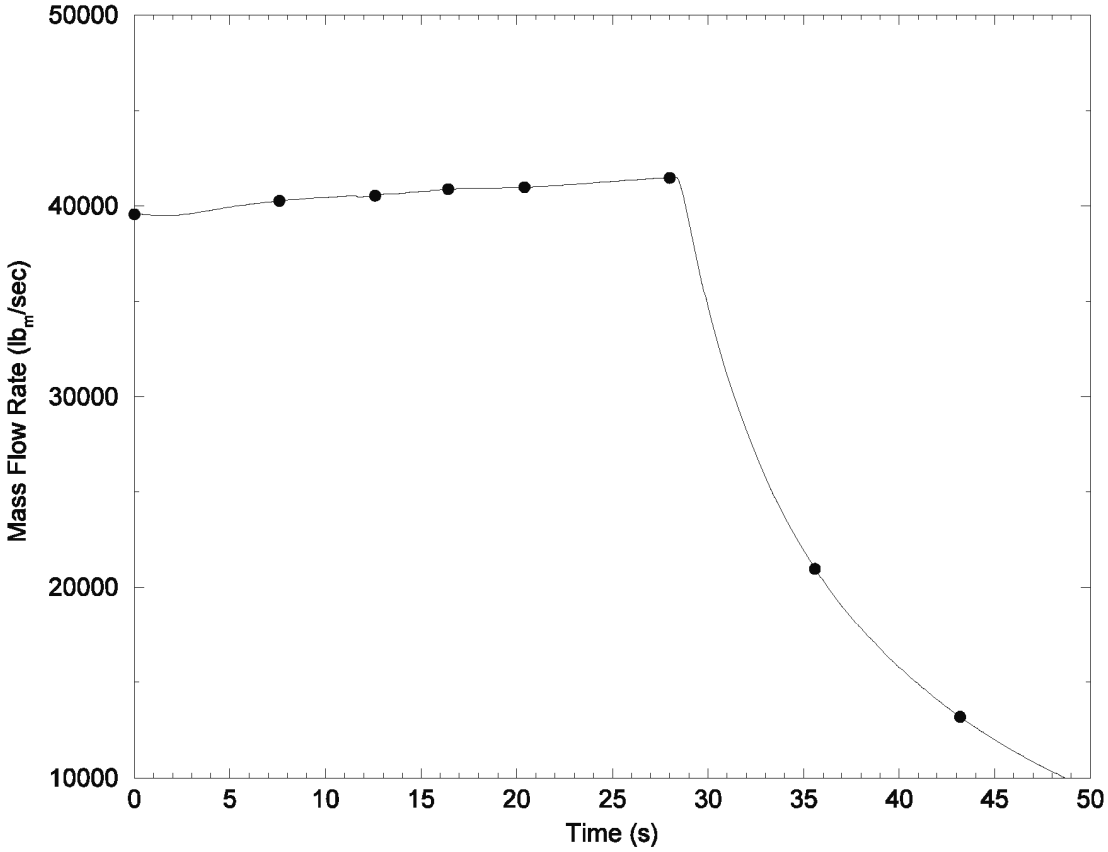

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Figure 15.1.3-5
Increased Steam Flow, HZP (AREVA):
RCS Total Loop Flow Rate vs. Time

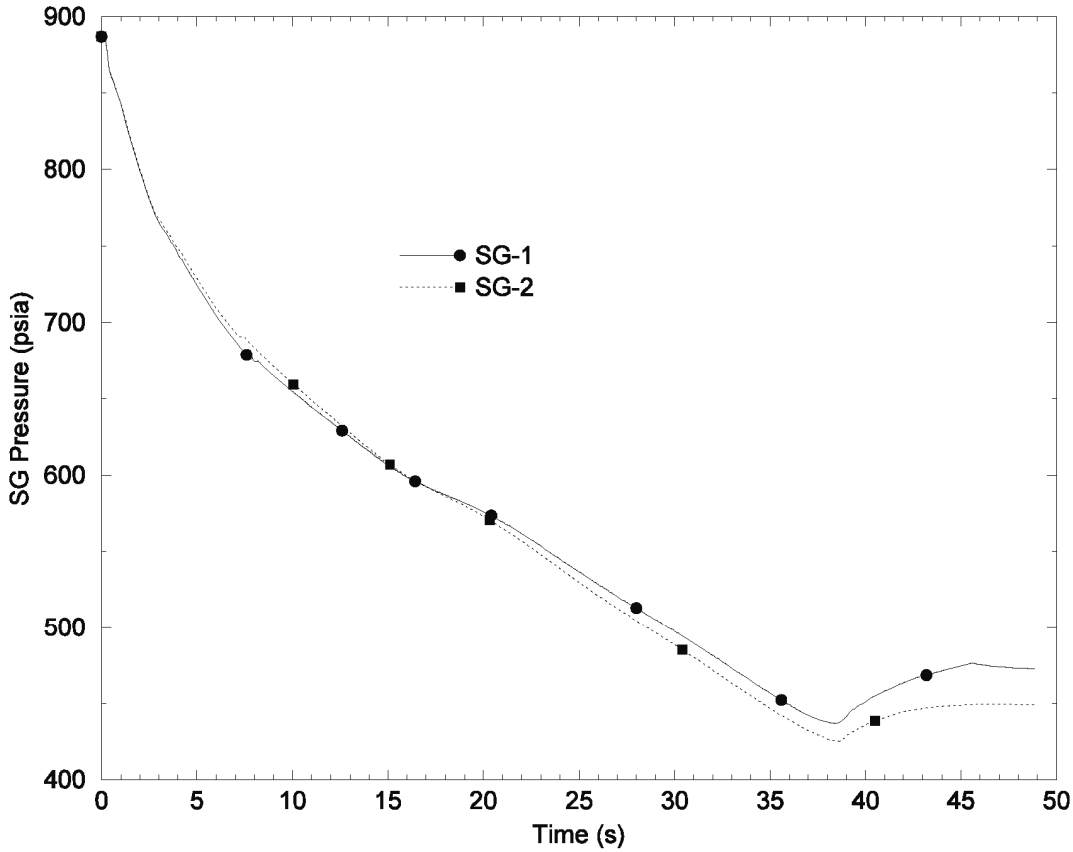

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Figure 15.1.3-6
Increased Steam Flow, HZP (AREVA):
Steam Generator Pressures vs. Time

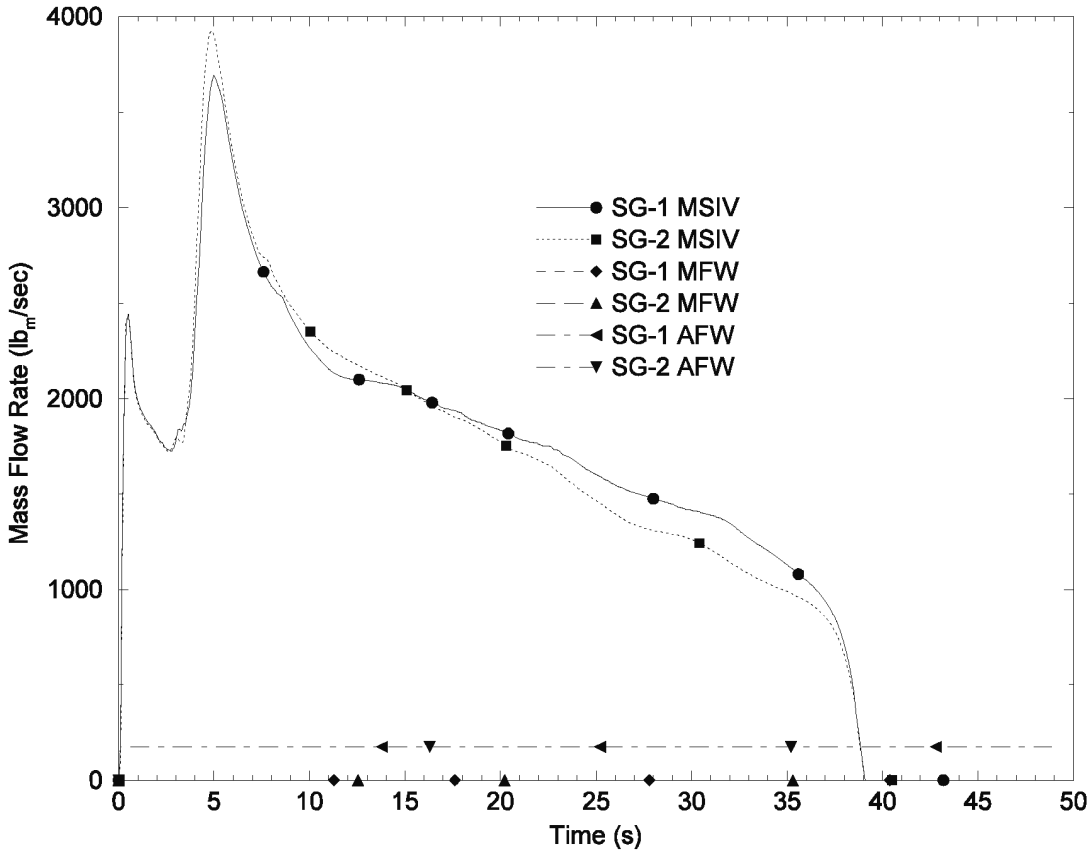

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Figure 15.1.3-7
Increased Steam Flow, HZP (AREVA):
Steam Line and Feedwater
Flow Rates vs. Time

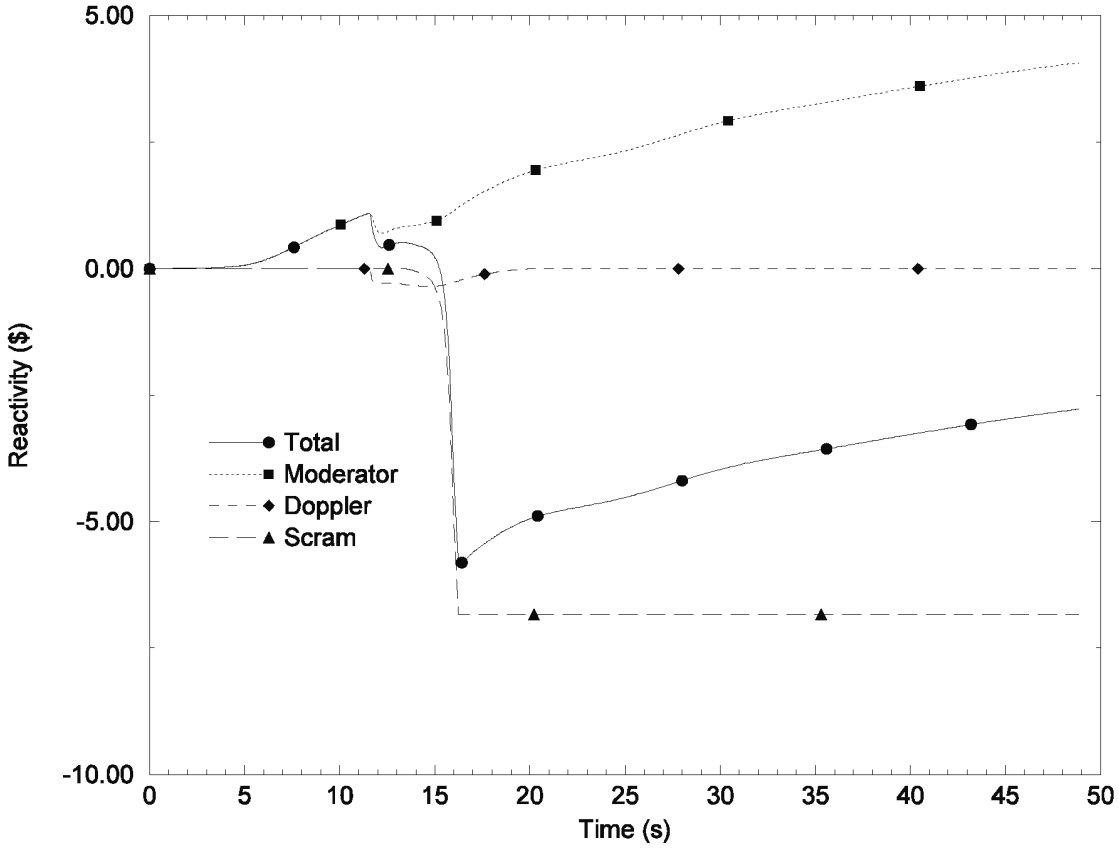

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Figure 15.1.3-8
Increased Steam Flow, HZP (AREVA):
Reactivity Feedback vs. Time

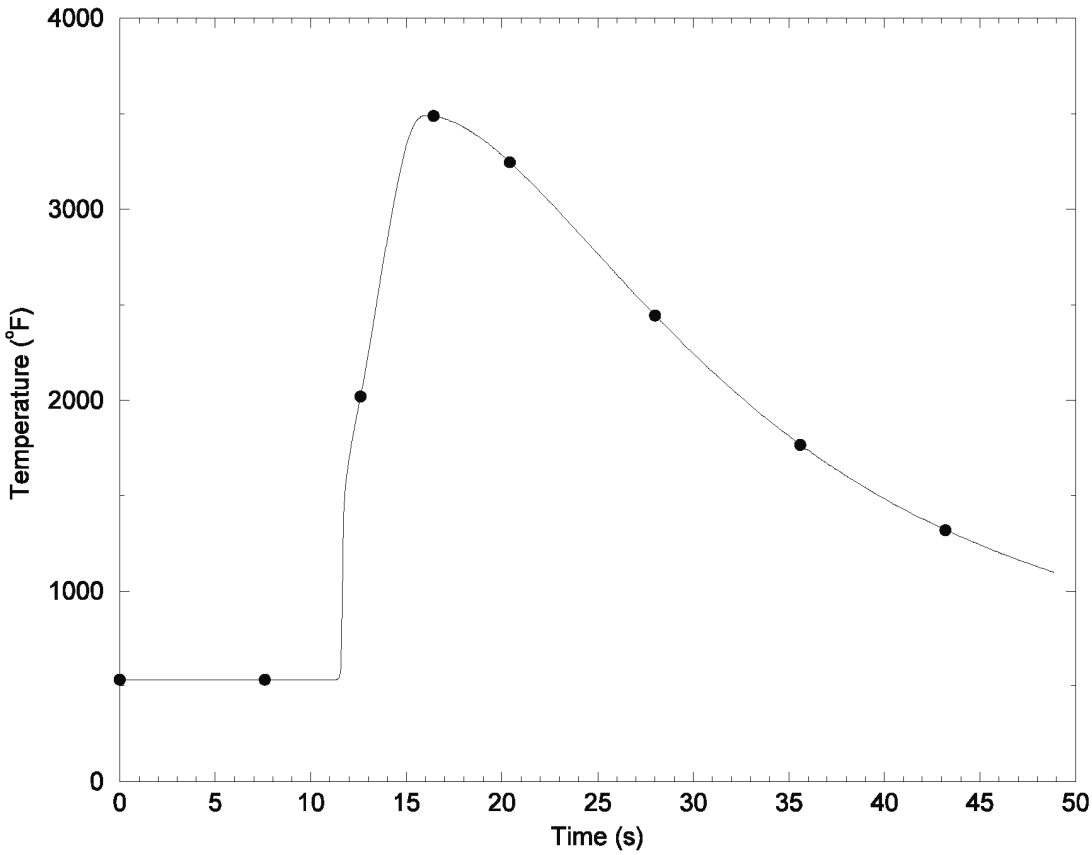

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Figure 15.1.3-9
Increased Steam Flow, HZP (AREVA):
Peak Fuel Centerline Temperature vs. Time

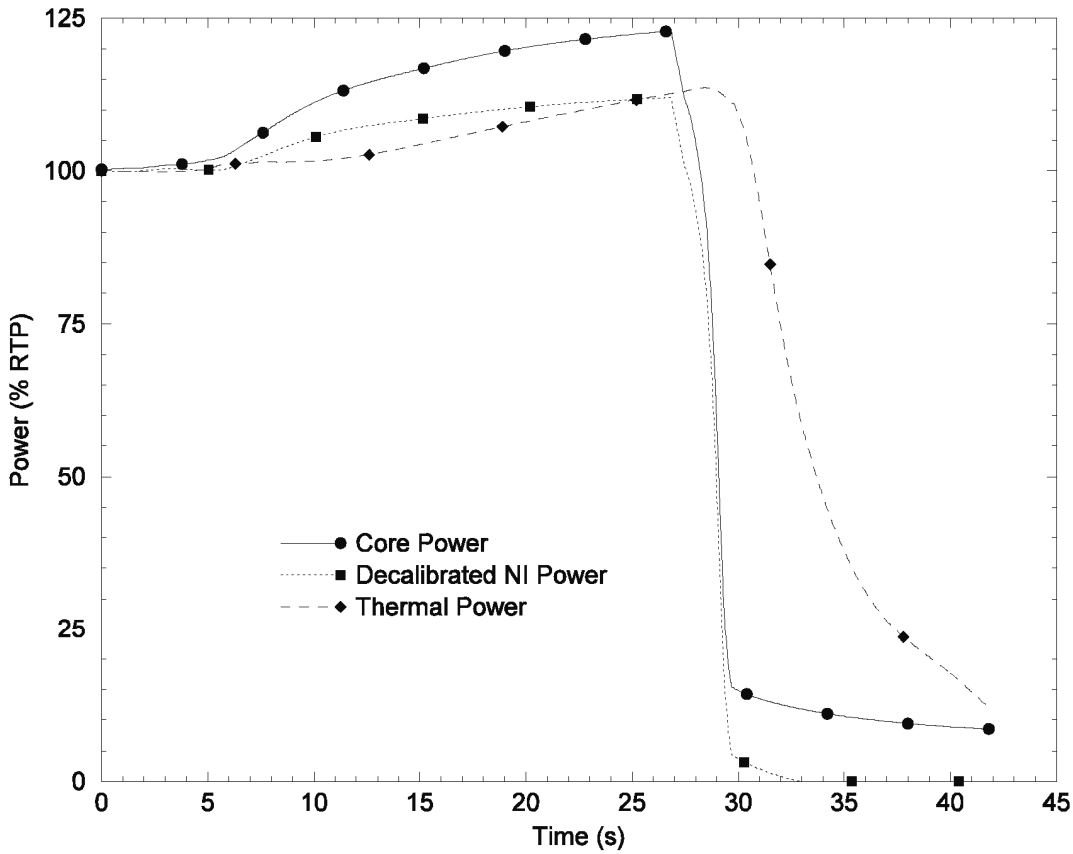

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Figure 15.1.3-10
Increased Steam Flow, Full Power (AREVA):
Reactor Power vs. Time

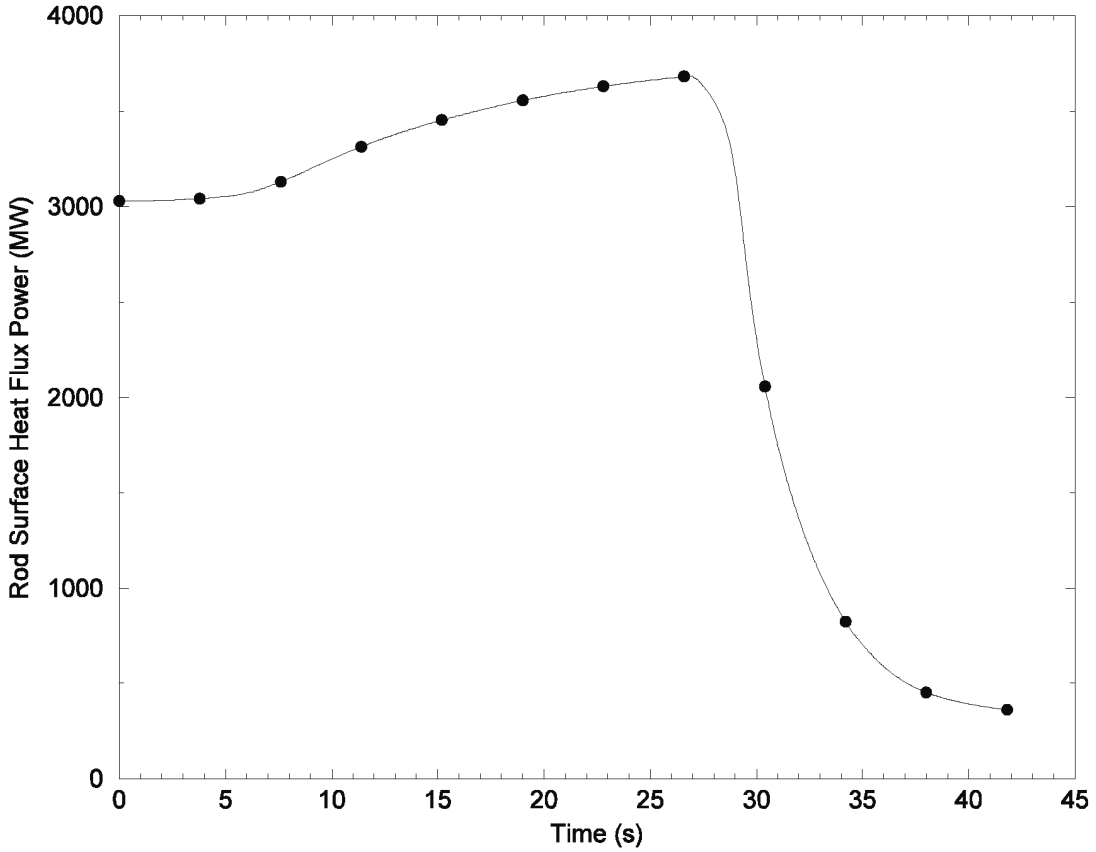

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Figure 15.1.3-11
Increased Steam Flow, Full Power (AREVA):
Total Core Heat Flux Power vs. Time

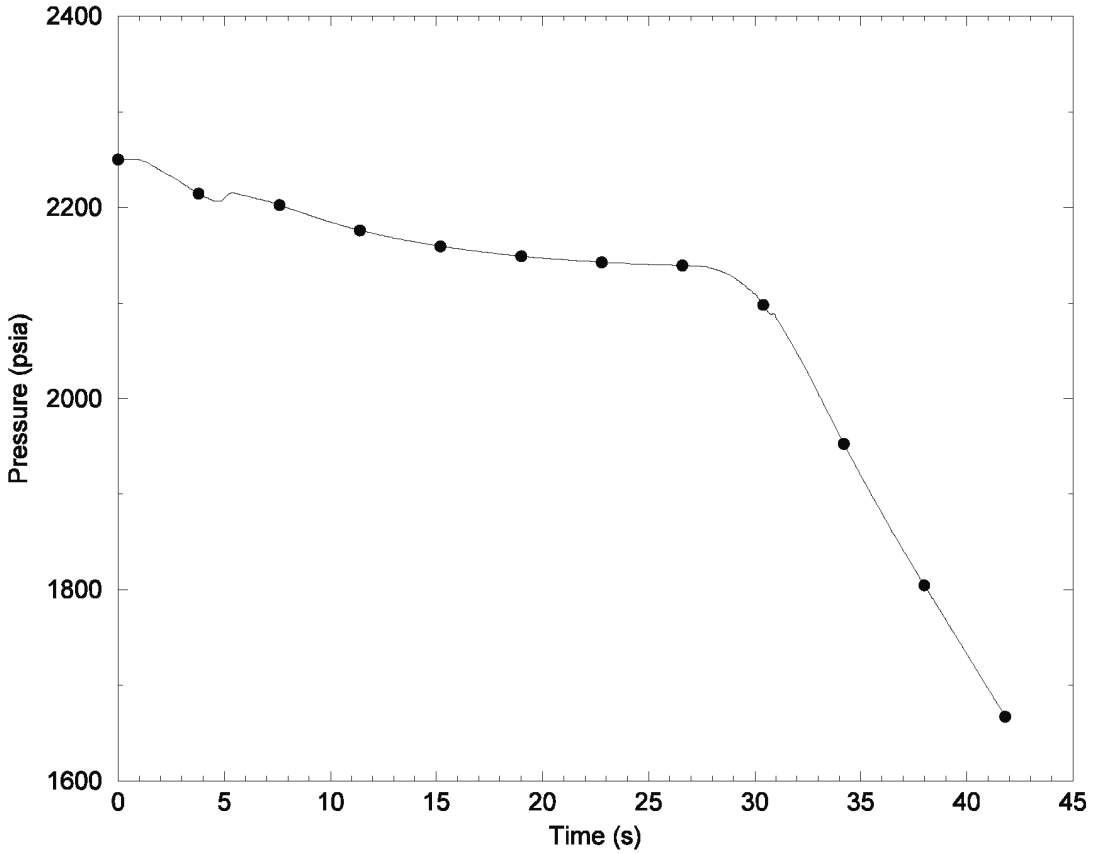

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Figure 15.1.3-12
Increased Steam Flow, Full Power (AREVA):
Pressurizer Pressure vs. Time

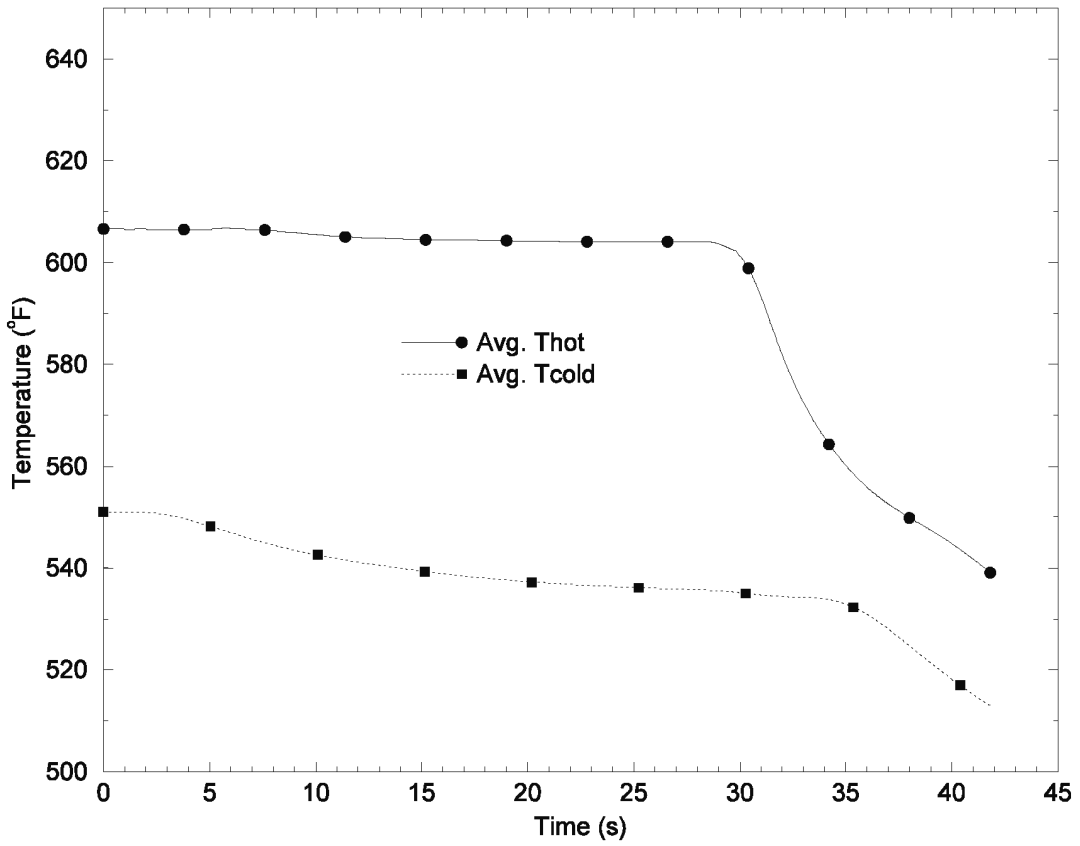

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Figure 15.1.3-13
Increased Steam Flow, Full Power (AREVA):
RCS Loop Temperatures vs. Time

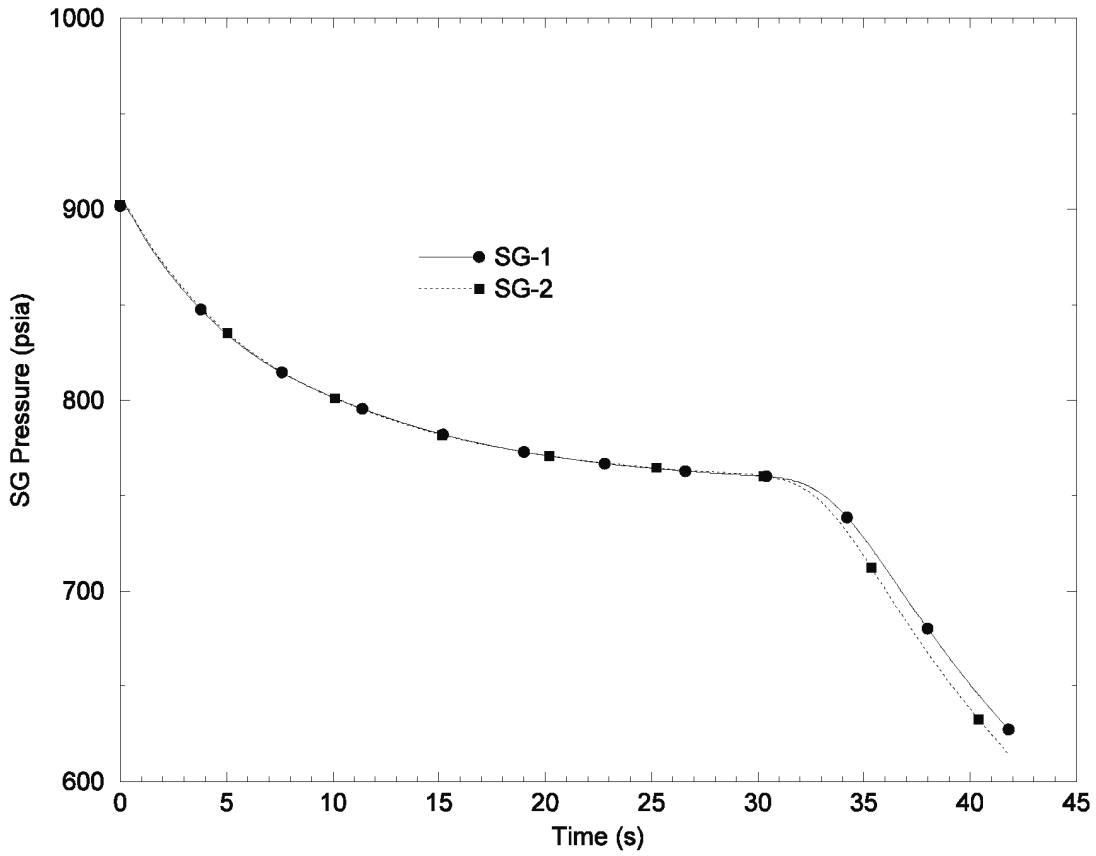

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Figure 15.1.3-14
Increased Steam Flow, Full Power (AREVA):
Steam Generator Pressures vs. Time

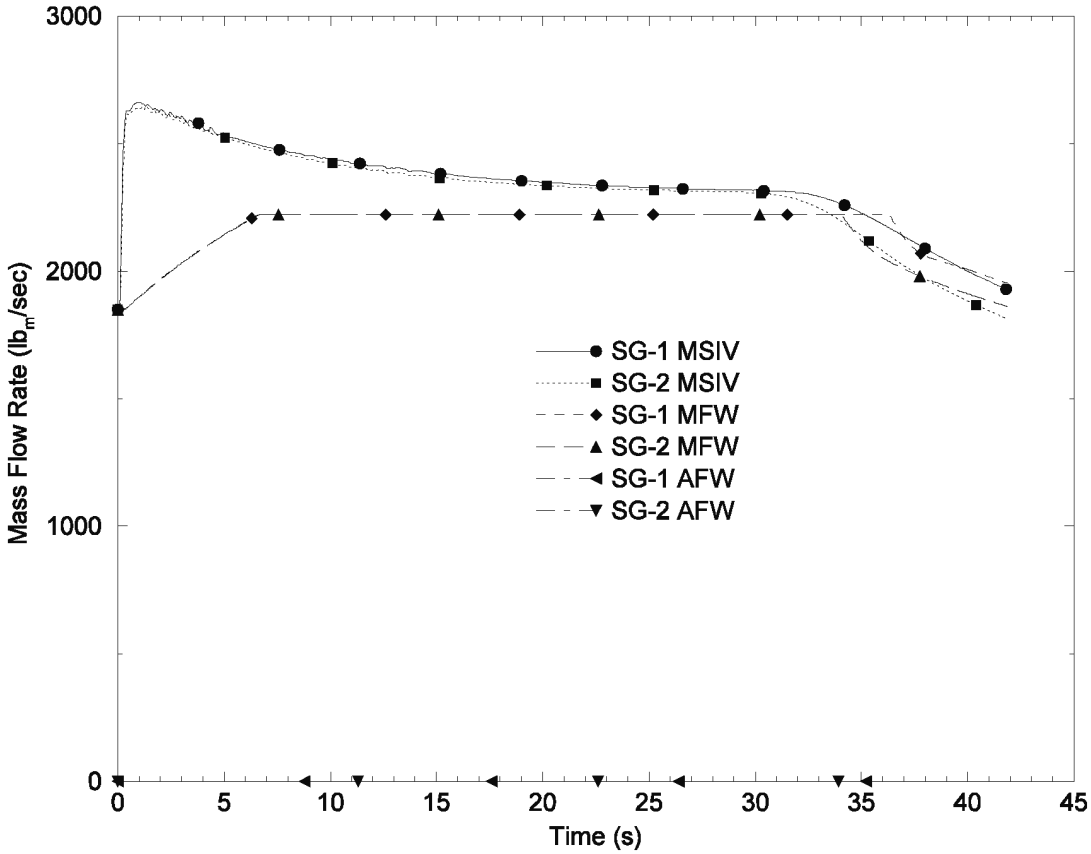

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Figure 15.1.3-15
Increased Steam Flow, Full Power (AREVA):
Steam Line and Feedwater
Flow Rates vs. Time

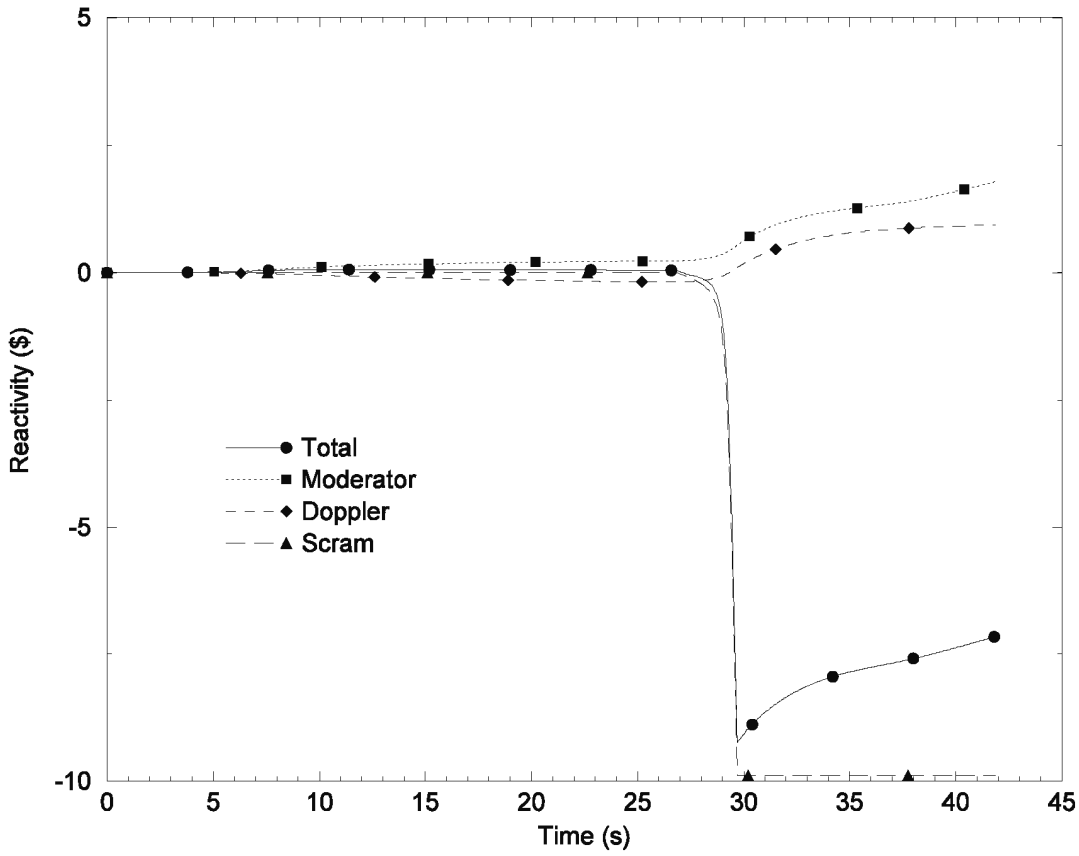

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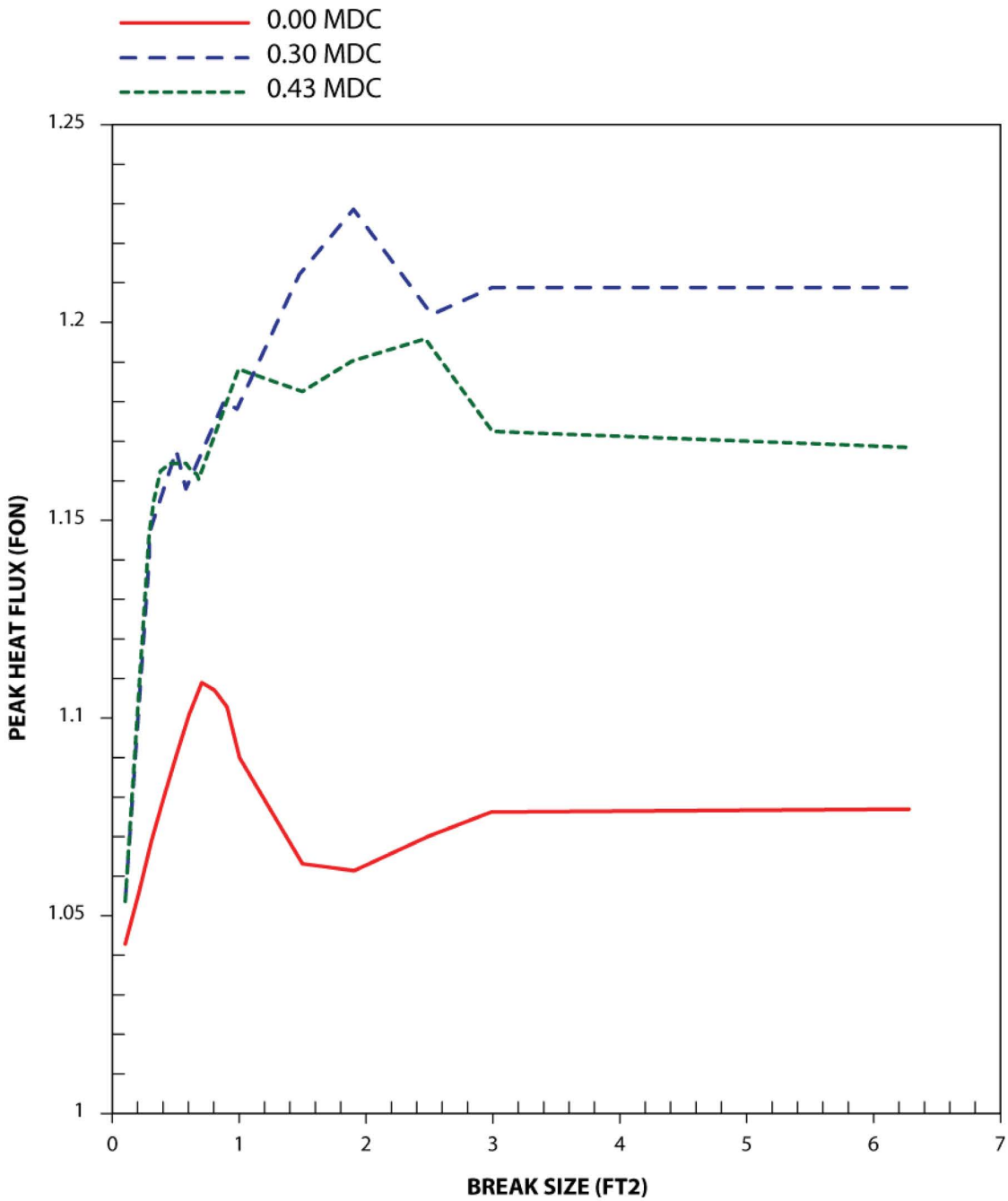
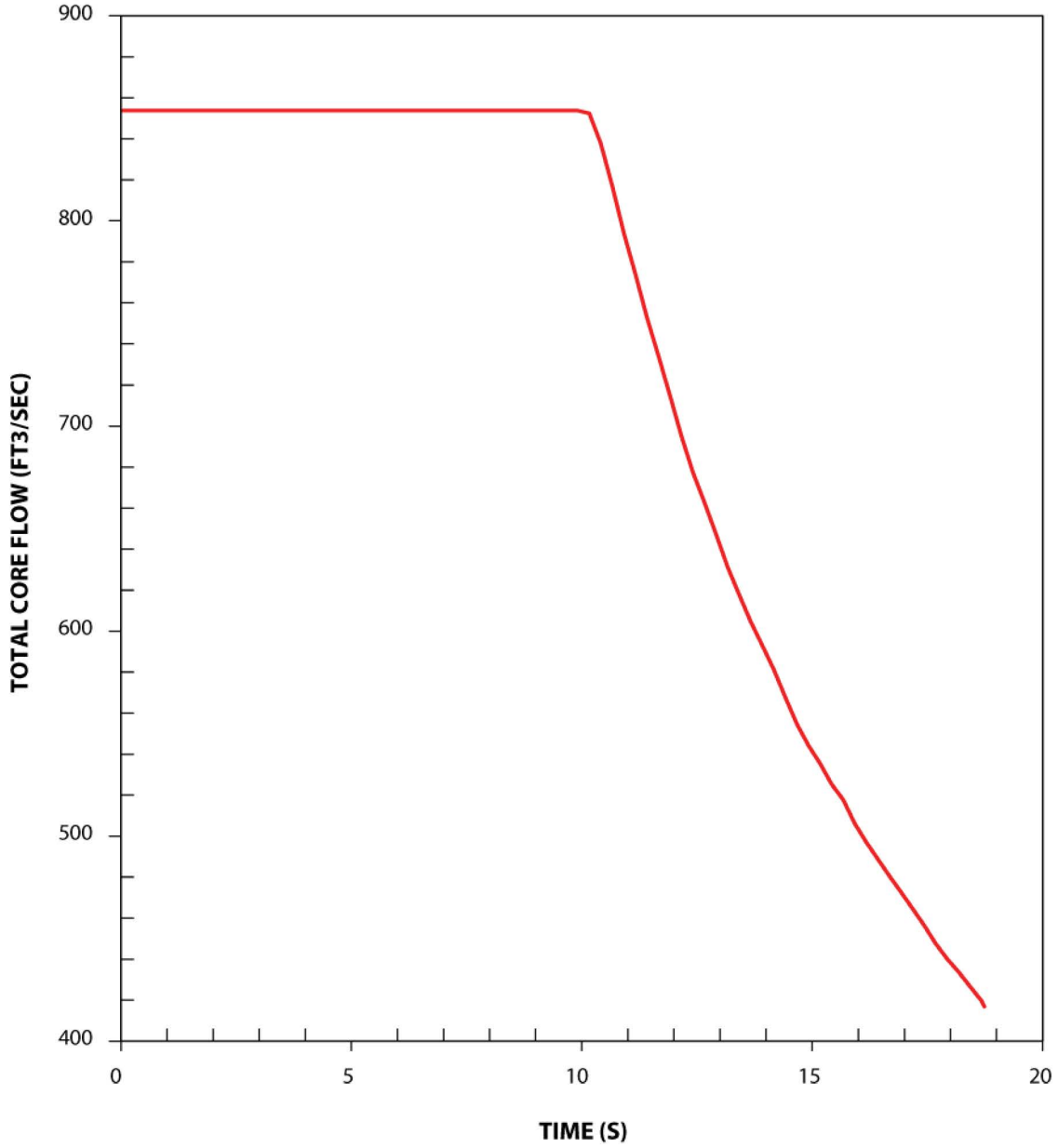
Figure 15.1.3-16
Increased Steam Flow, Full Power (AREVA):
Reactivity Feedback vs. Time

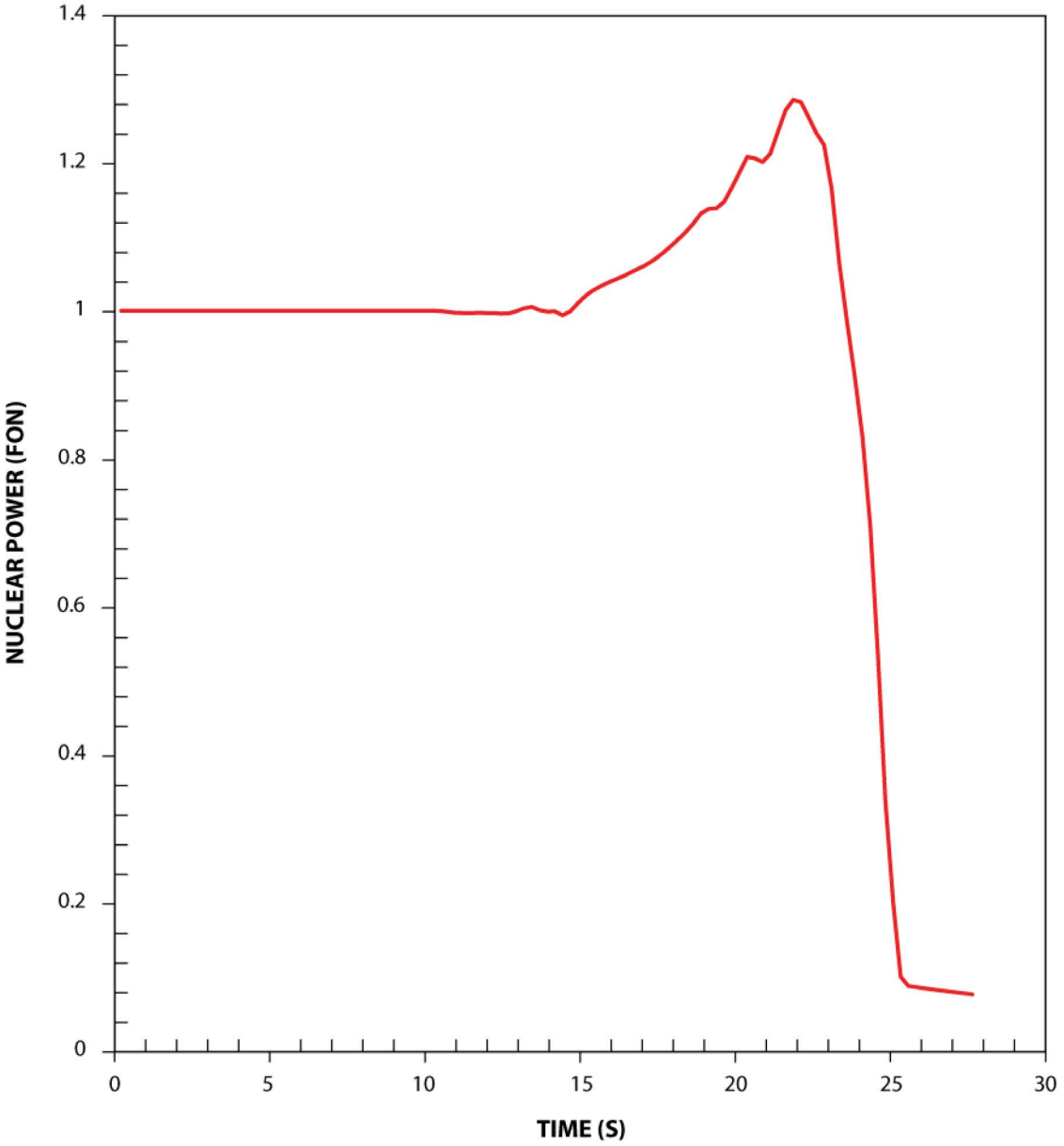


FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-1a Pre-Trip Main Steamline Break - FFBT Peak Core Heat Flux vs. Break Size for a Spectrum of MDCs



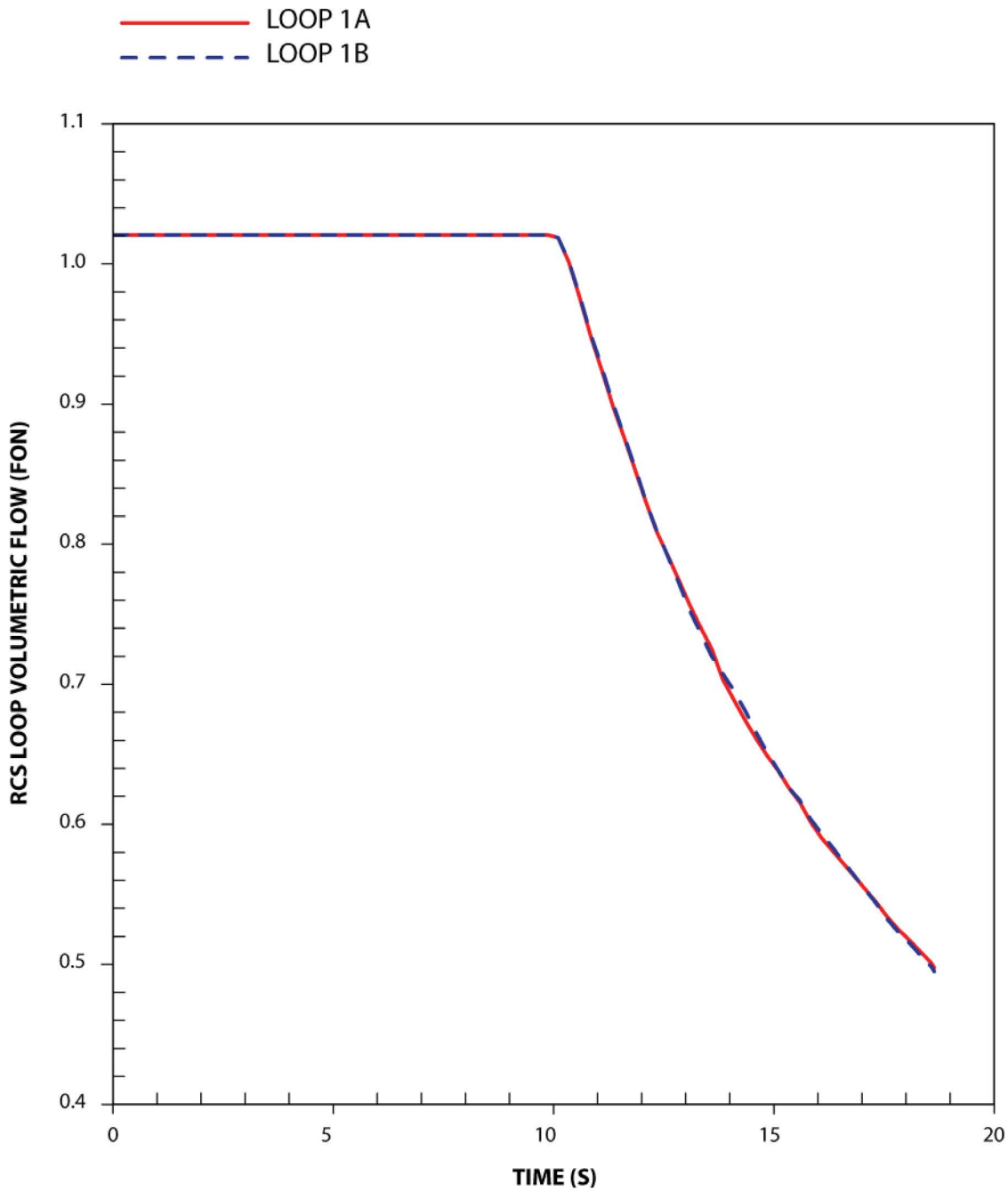
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-1b Pre-Trip Main Steamline Break - LOOP Total Core Inlet Flow vs. Time



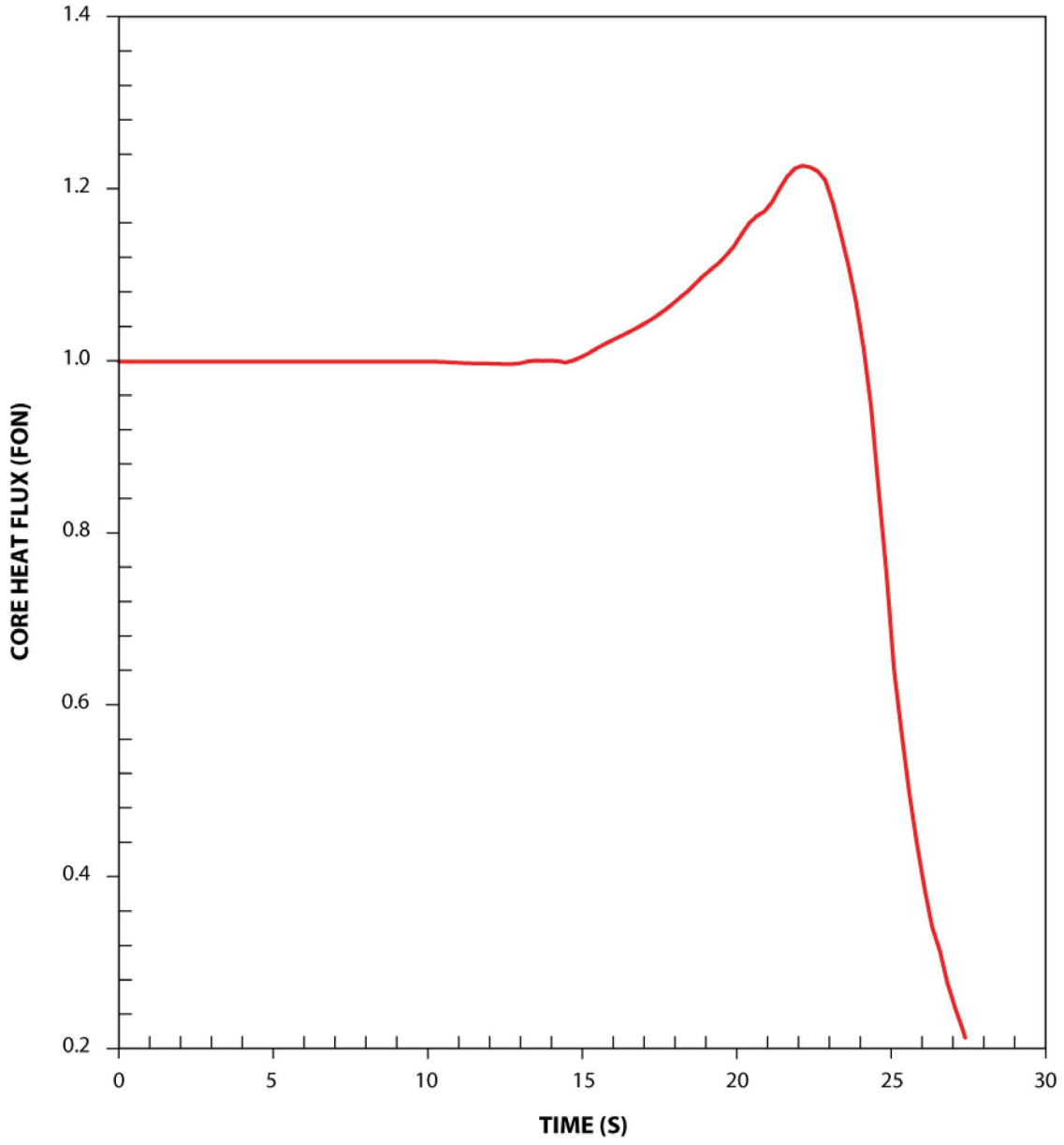
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-2a Pre-Trip Main Steamline Break - FFBT Nuclear Power vs. Time



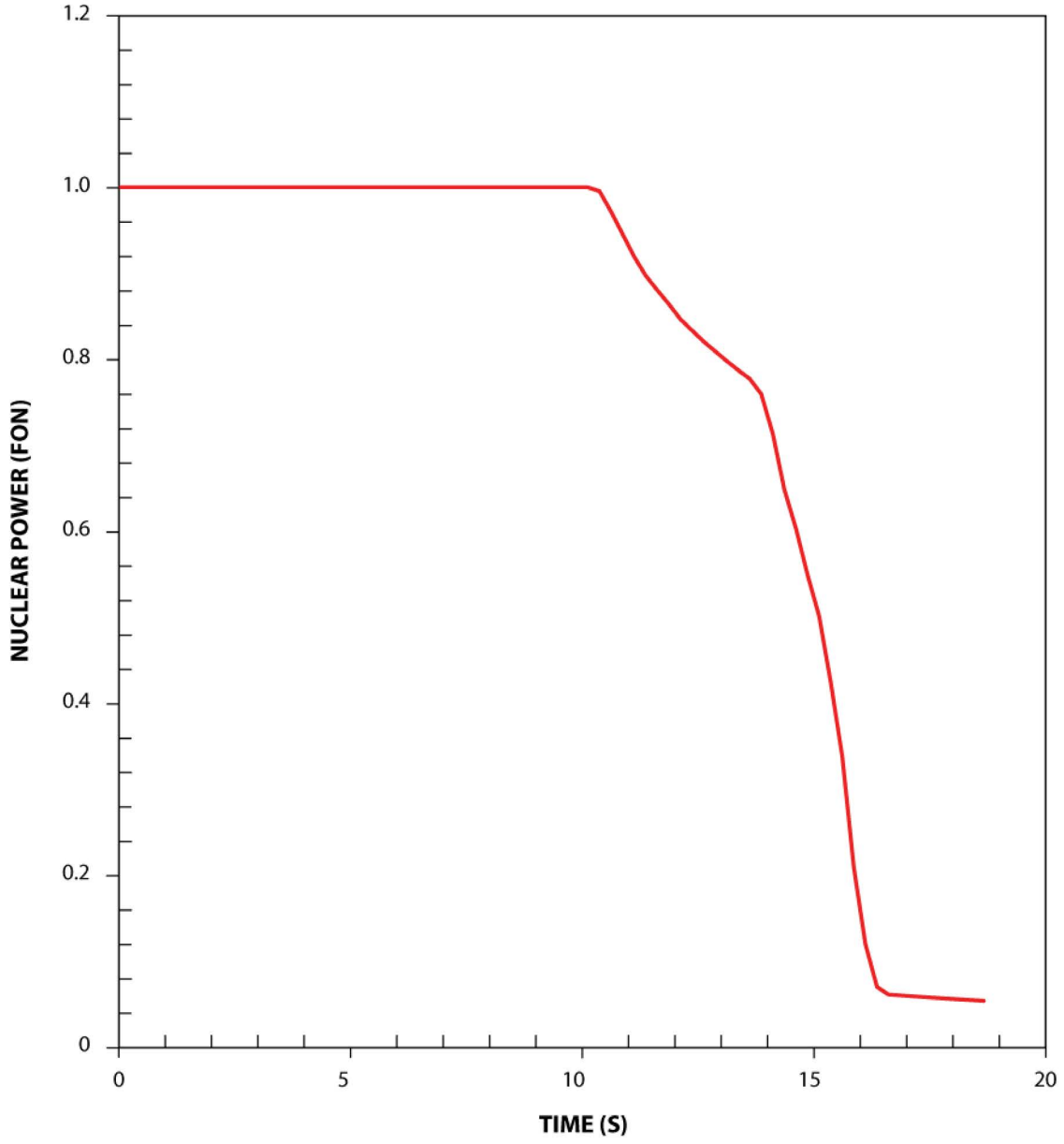
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-2b Pre-Trip Main Steamline Break - LOOP RCS Loop Volumetric Flow vs. Time



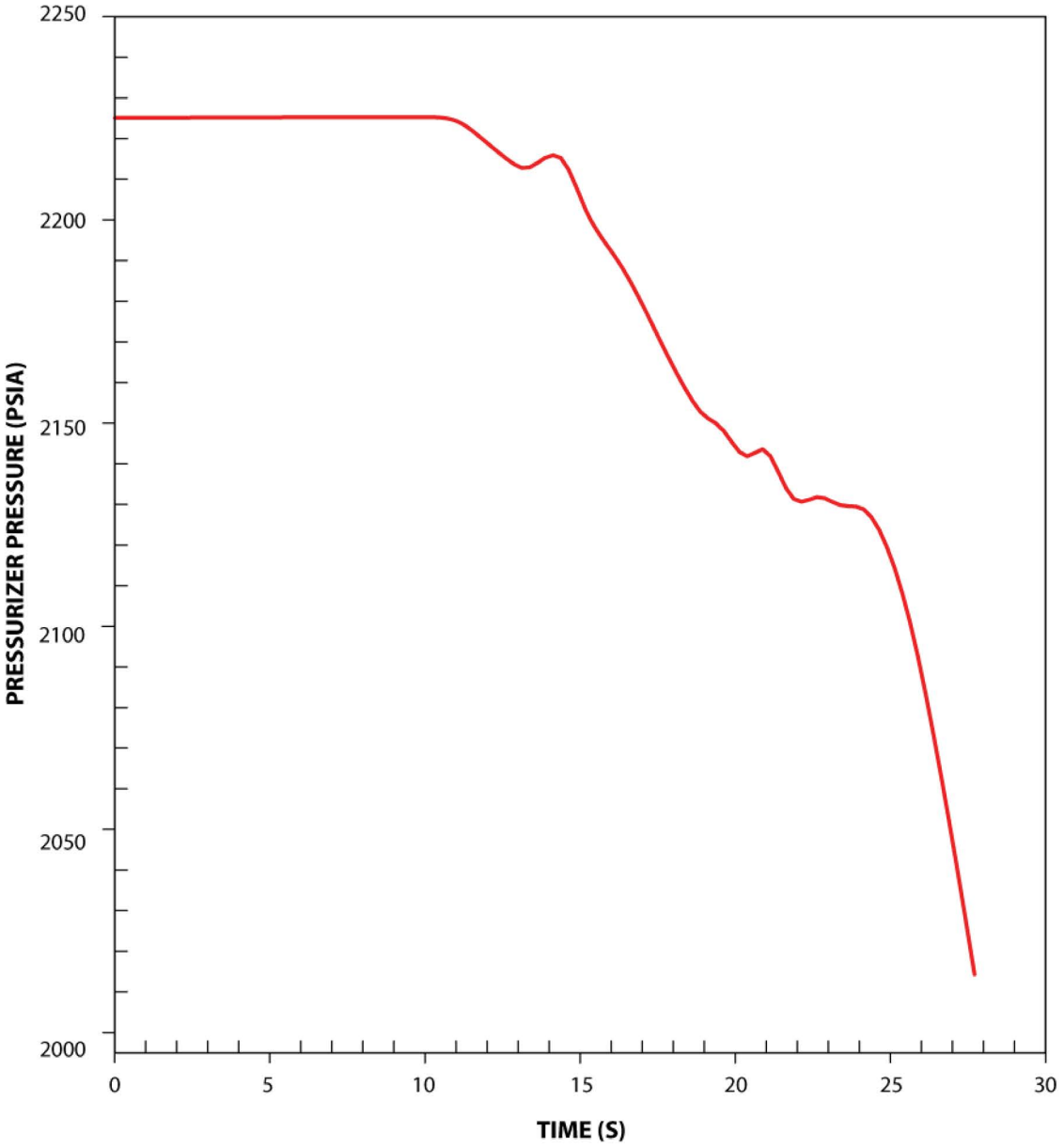
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-3a Pre-Trip Main Steamline Break - FFBT Core Heat Flux vs. Time



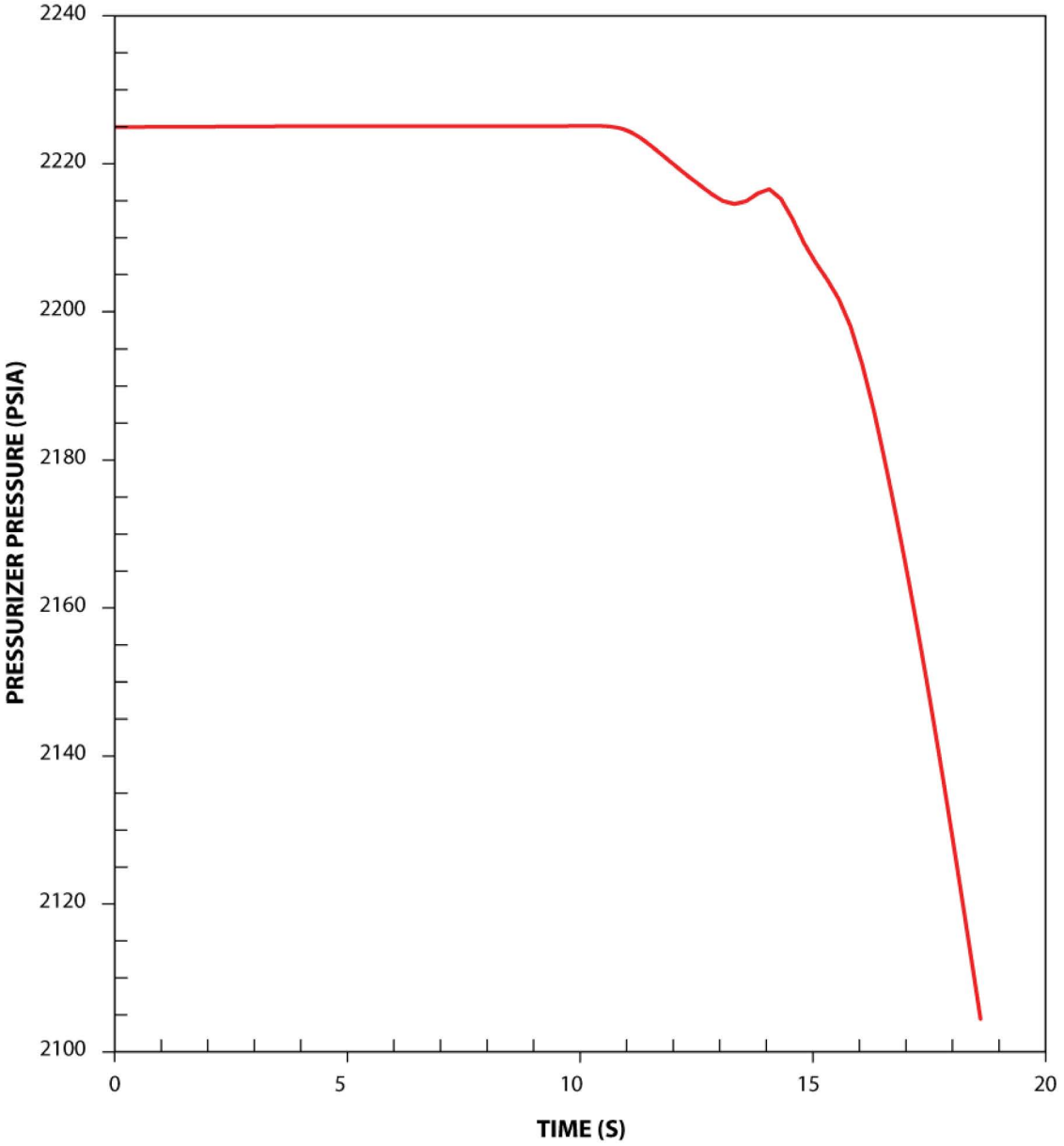
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-3b Pre-Trip Main Steamline Break - LOOP Nuclear Power vs. Time



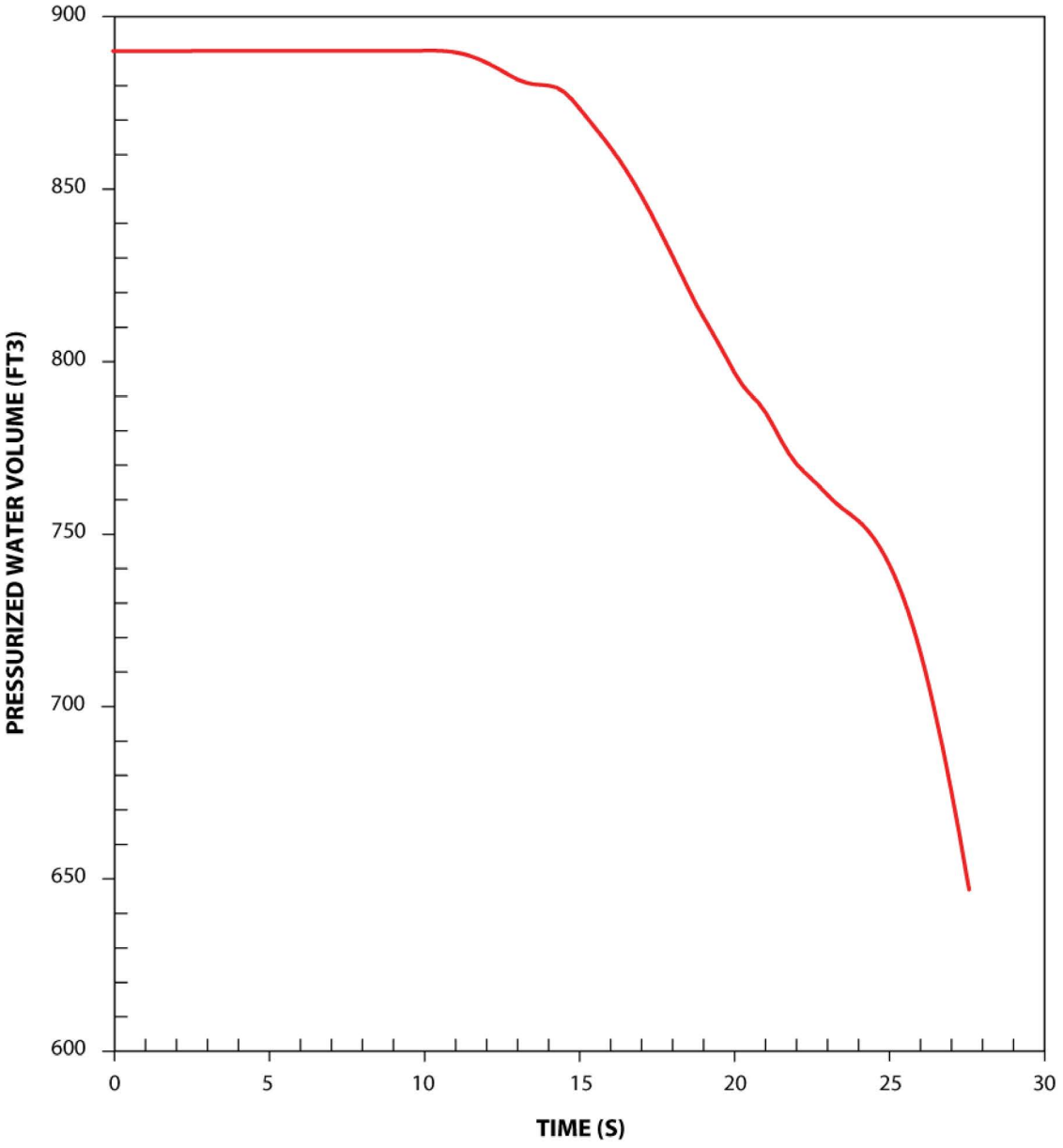
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-4a Pre-Trip Main Steamline Break - FFBT Pressurizer Pressure vs. Time



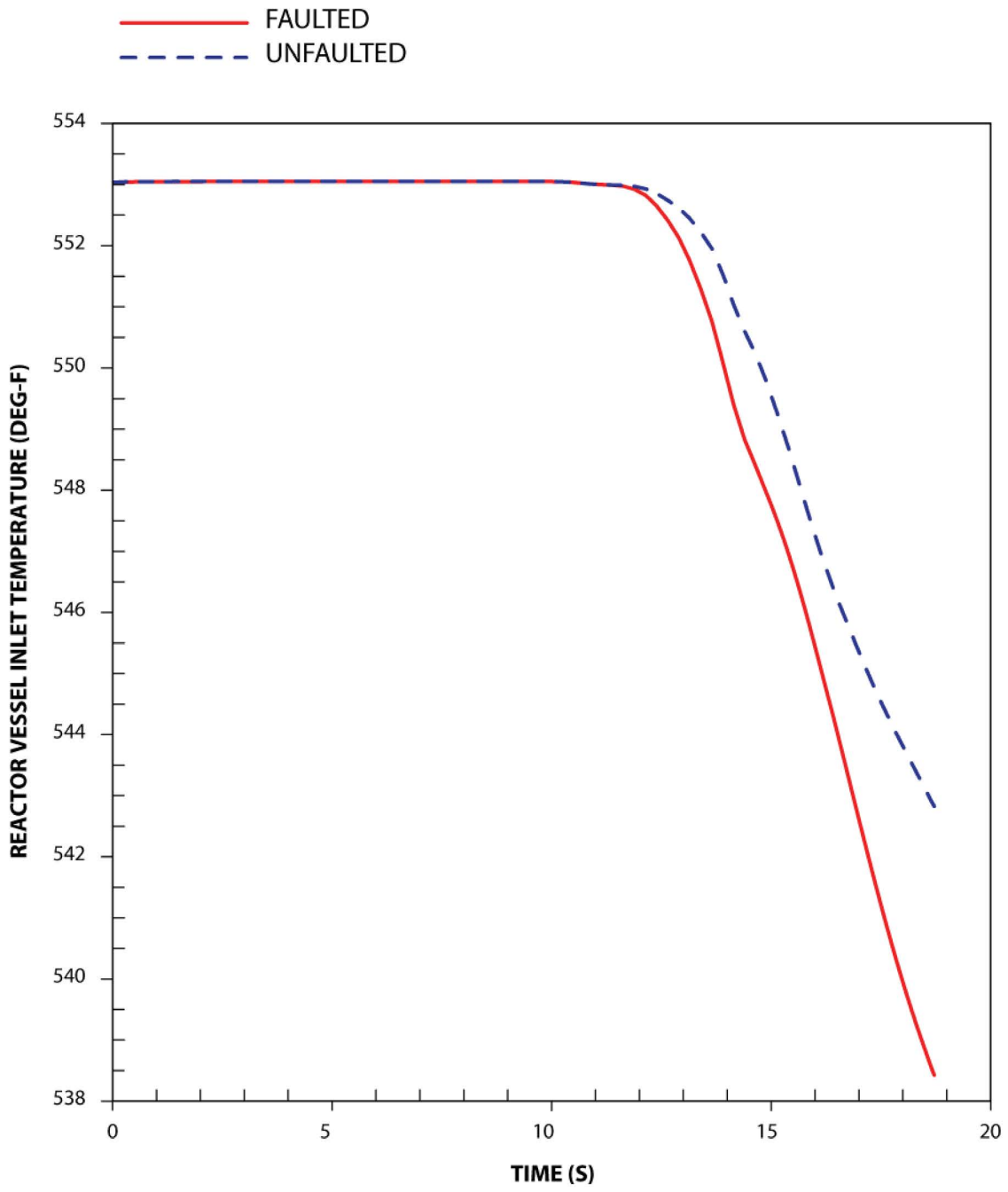
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-4b Pre-Trip Main Steamline Break - LOOP Pressurizer Pressure vs. Time



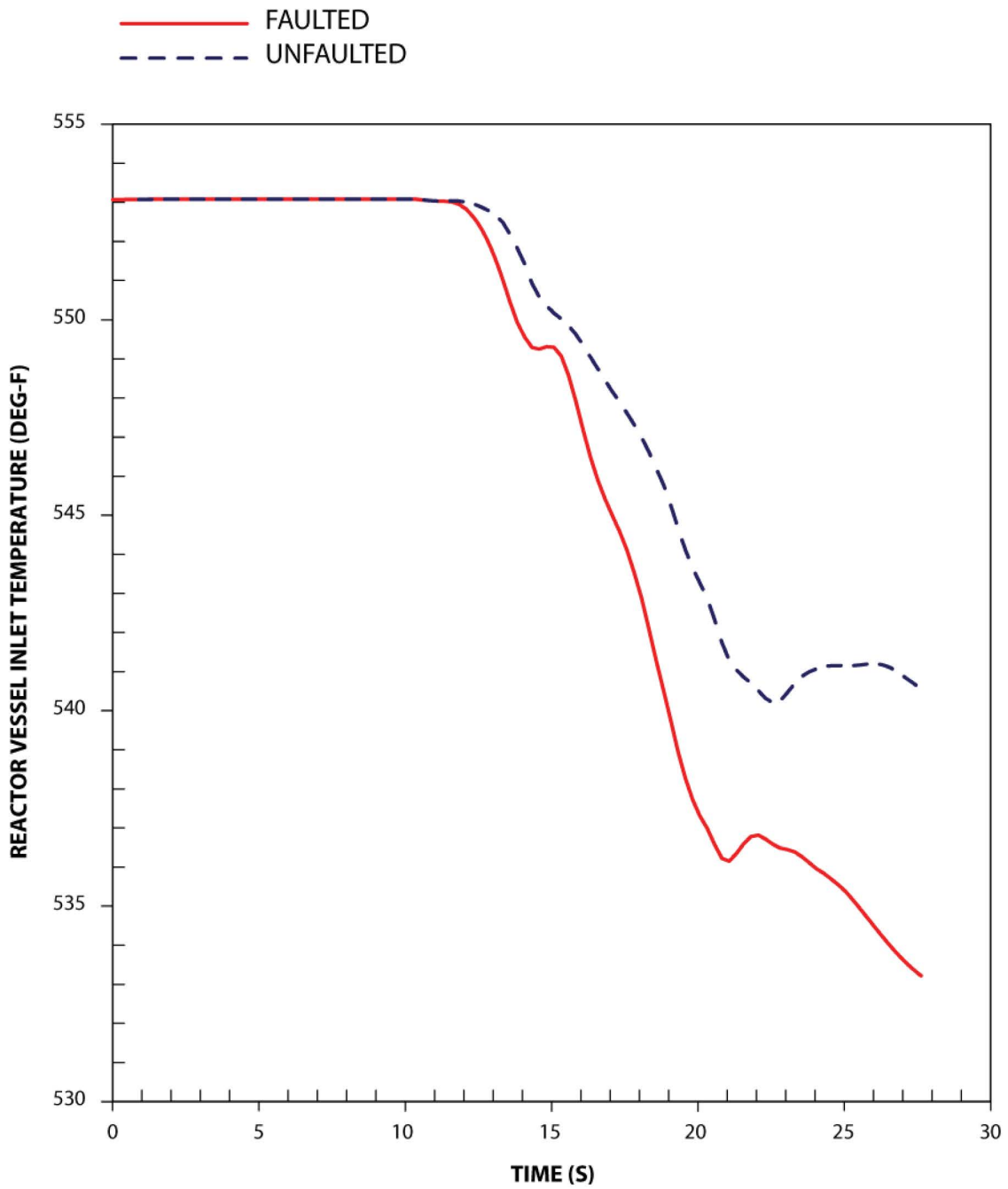
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-5a Pre-Trip Main Steamline Break - FFBT Pressurizer Water Volume vs. Time



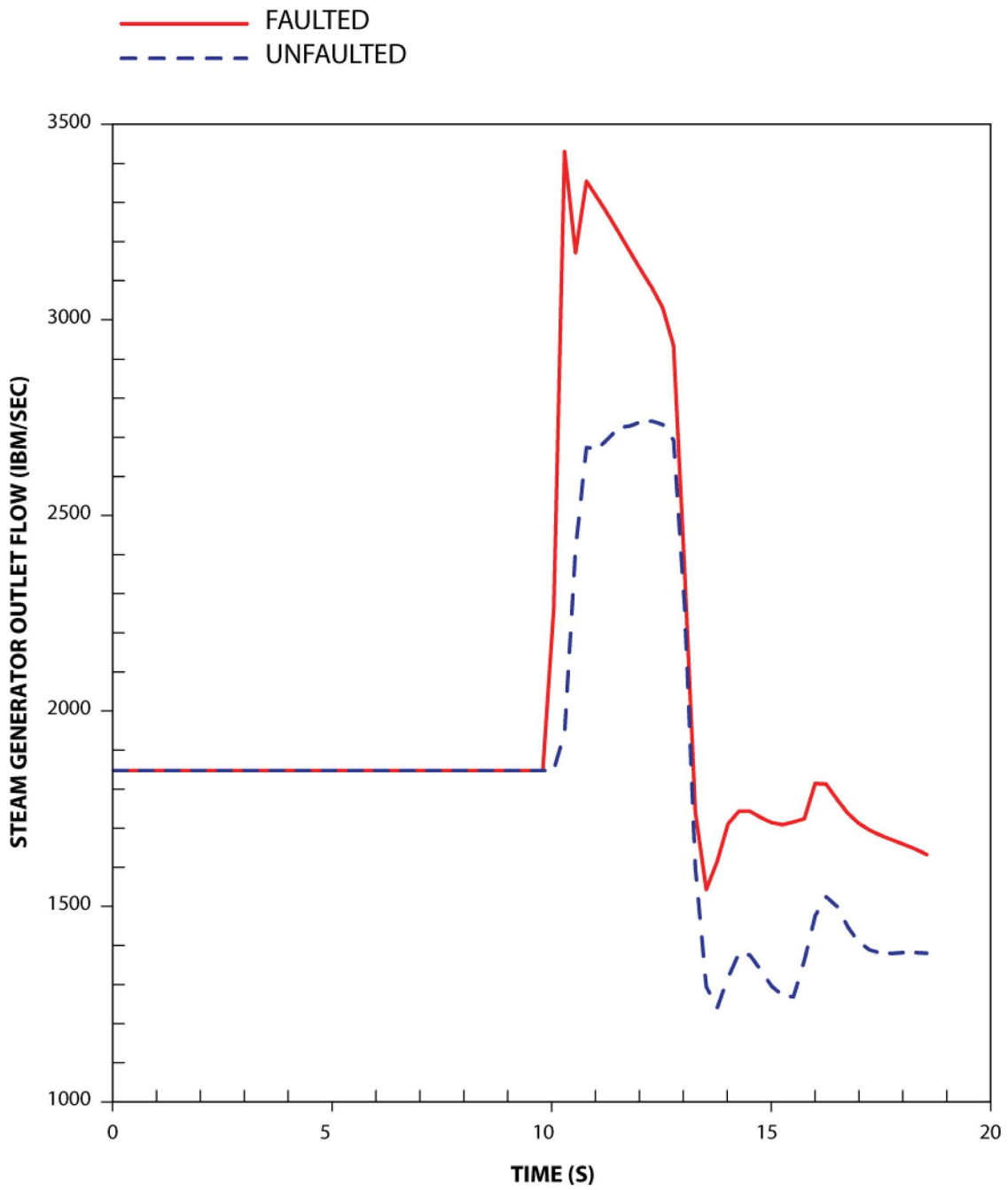
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-5b Pre-Trip Main Steamline Break - LOOP Inlet Temperature vs. Time



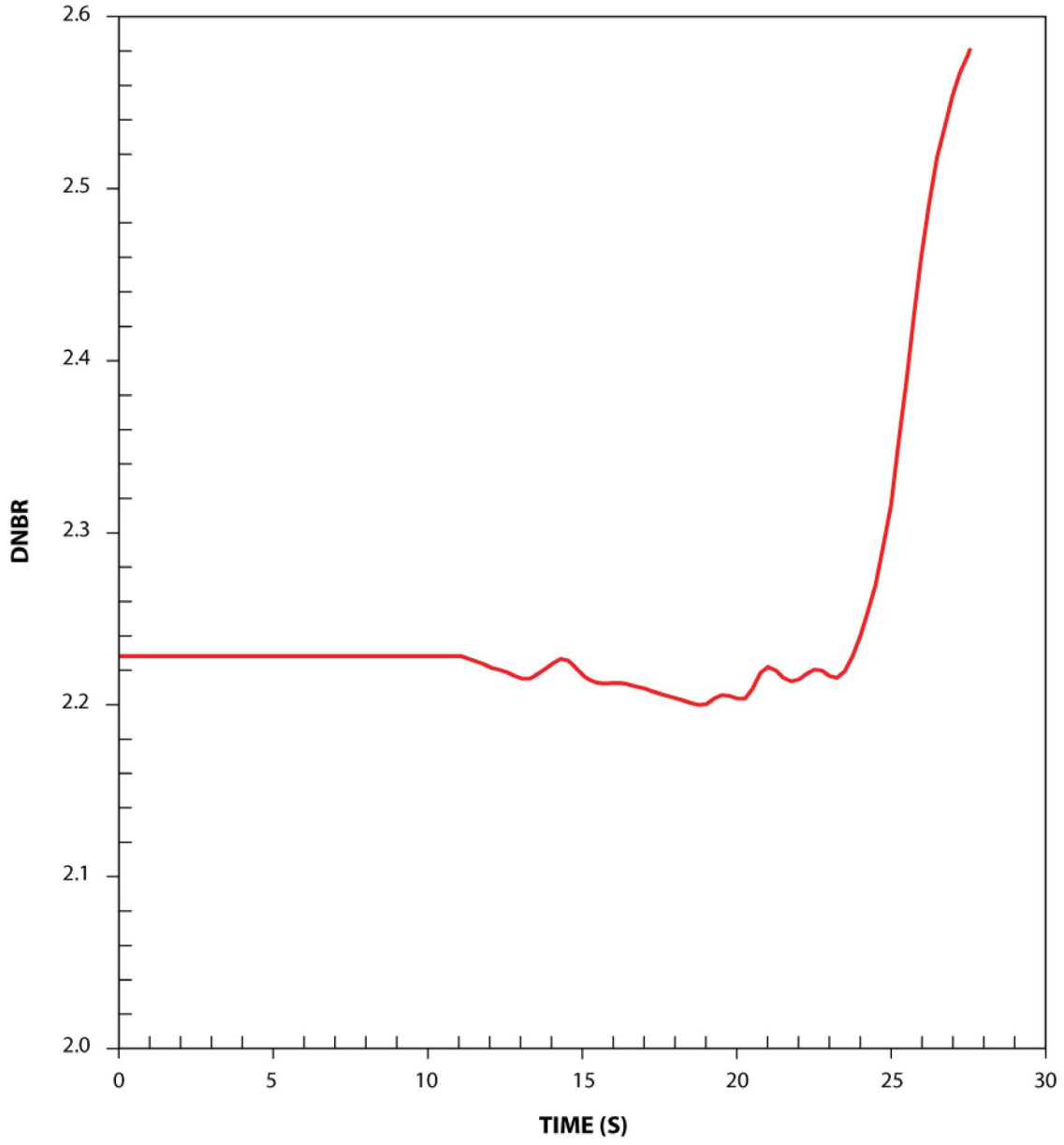
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-6a Pre-Trip Main Steamline Break - FFBT Reactor Vessel Inlet Temperature vs. Time



Note: Figure includes a 10 second steady state time period.

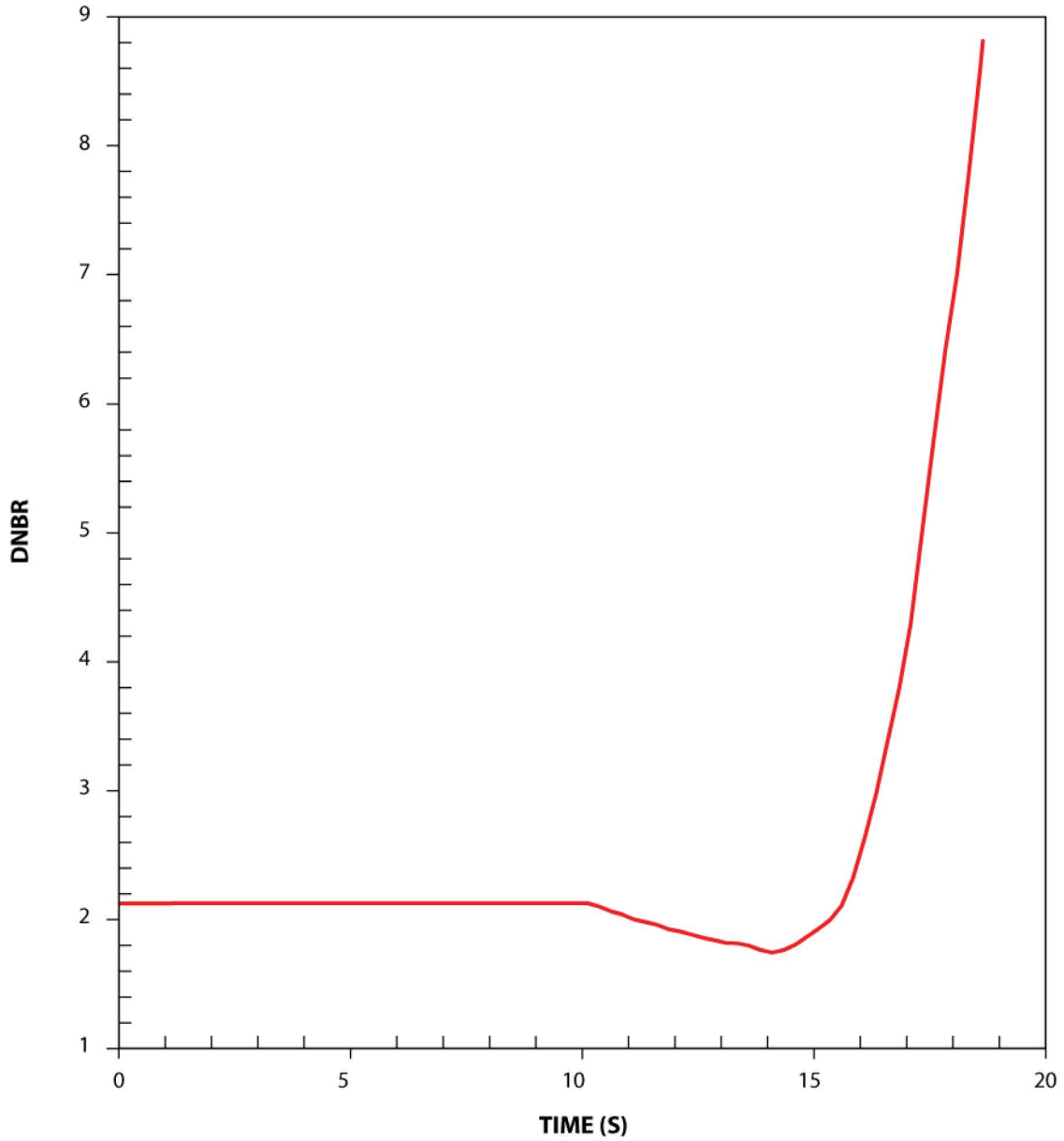
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-6b Pre-Trip Main Steamline Break - LOOP Steam Generator Outlet Flow vs. Time



Note: UFSAR Figure 15.1.5.-7a provides the RETRAN calculated DNBR similar to the current UFSAR Figure rather than the DNBR as calculated by the VIPRE code.

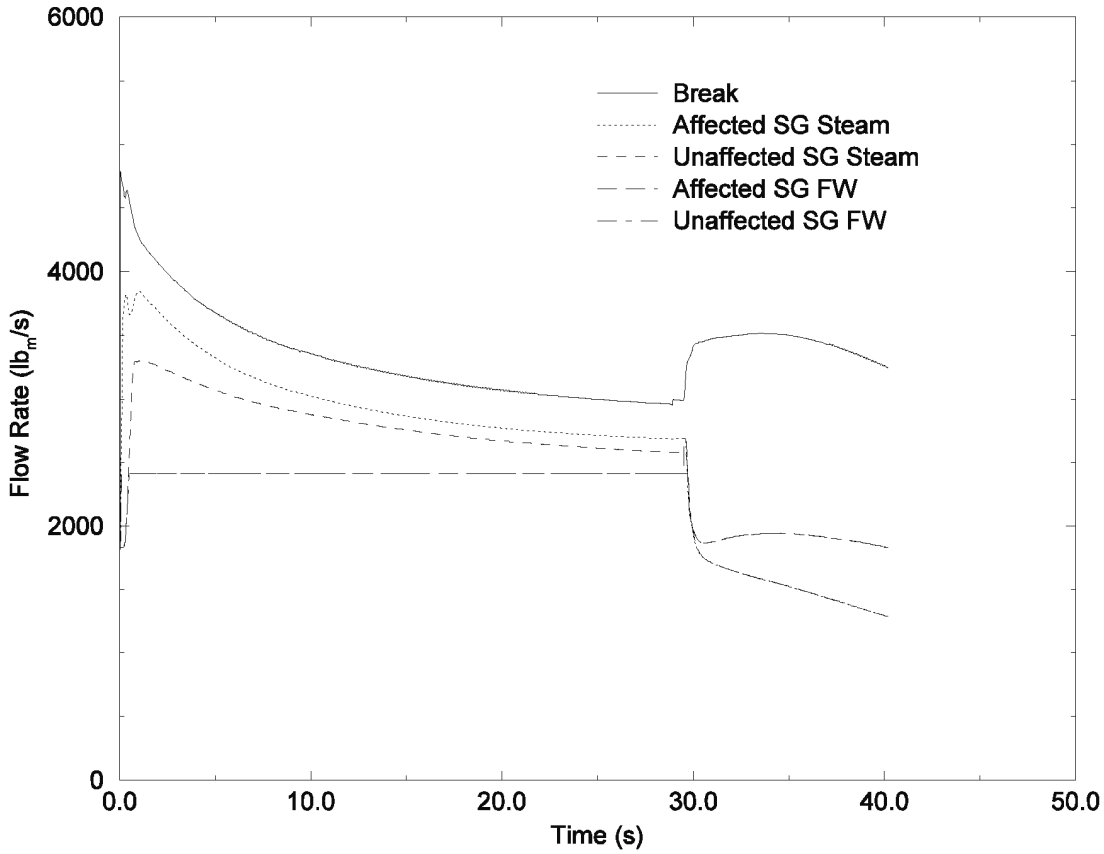
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-7a Pre-Trip Main Steamline Break - FFBT DNBR vs. Time



Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.5-7b Pre-Trip Main Steamline Break with LOOP DNBR vs. Time



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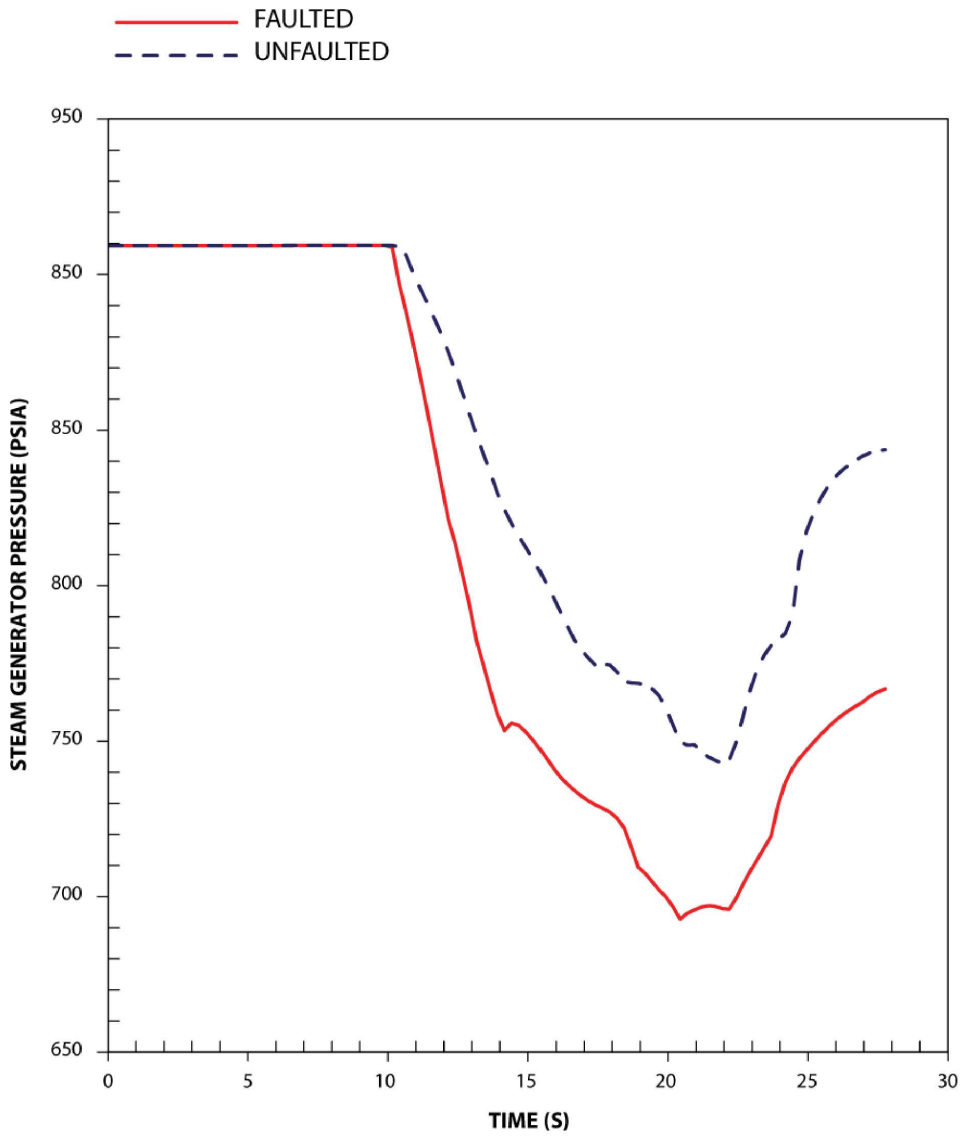
ST. LUCIE PLANT UNIT 2

Figure 15.1.5-8
Pre-Trip Main Steamline Break (AREVA):
Break, SG Steam, and Feedwater
Flow Rates vs. Time



Note: Figure includes a 10 second steady state time period.

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ST. LUCIE PLANT UNIT 2

Figure 15.1.5-8a
Pre-Trip Main Steamline Break - FFBT
Steam Generator Steam Pressure vs. Time

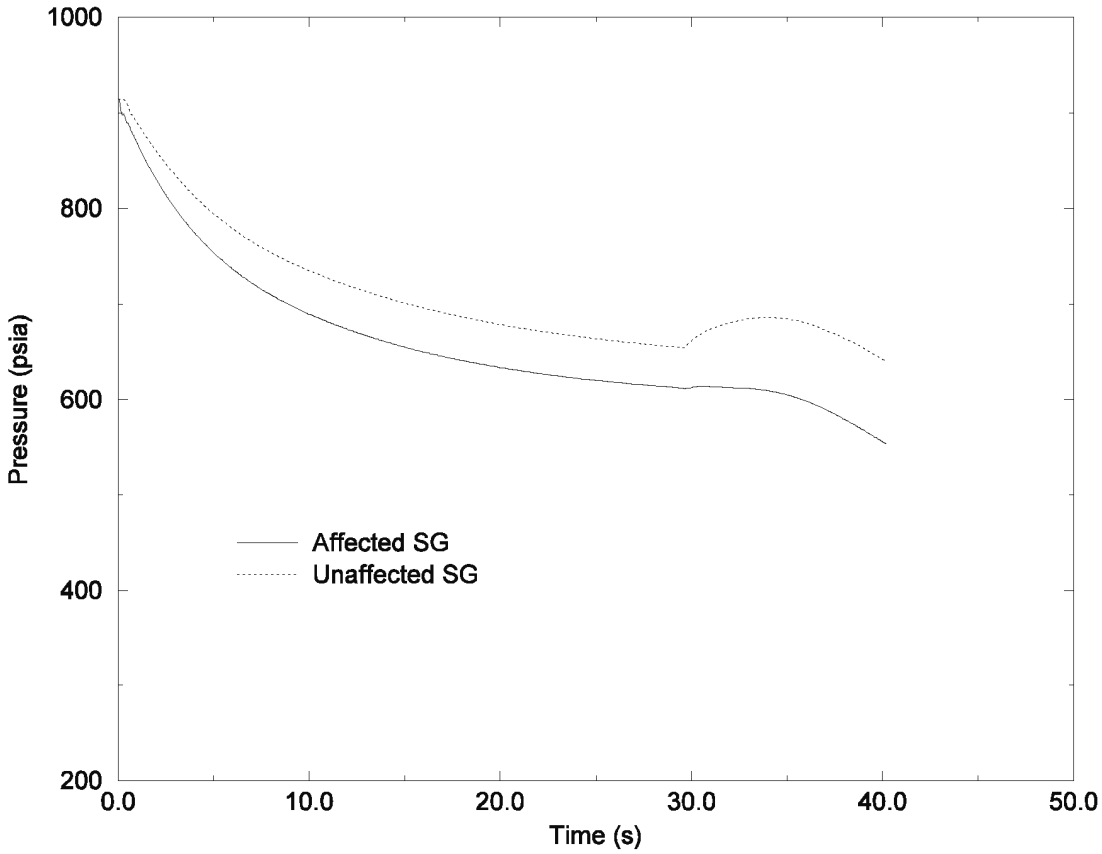

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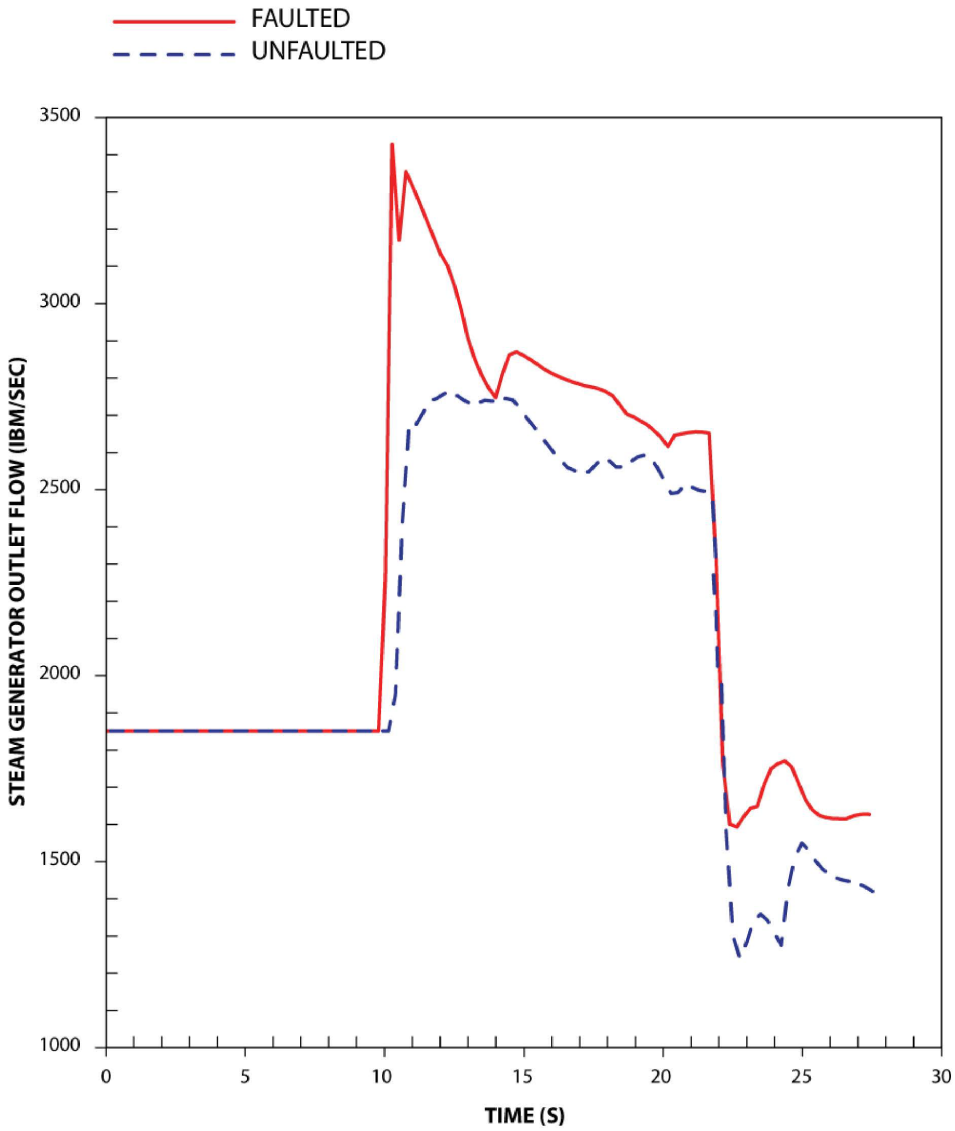
Figure 15.1.5-9
Pre-Trip Main Steamline Break (AREVA):
Steam Generator Secondary
Pressures vs. Time



Note: Figure includes a 10 second steady state time period.

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ST. LUCIE PLANT UNIT 2

Figure 15.1.5-9a
Pre-Trip Main Steamline Break - FFBT
Loop Steam Rate vs. Time

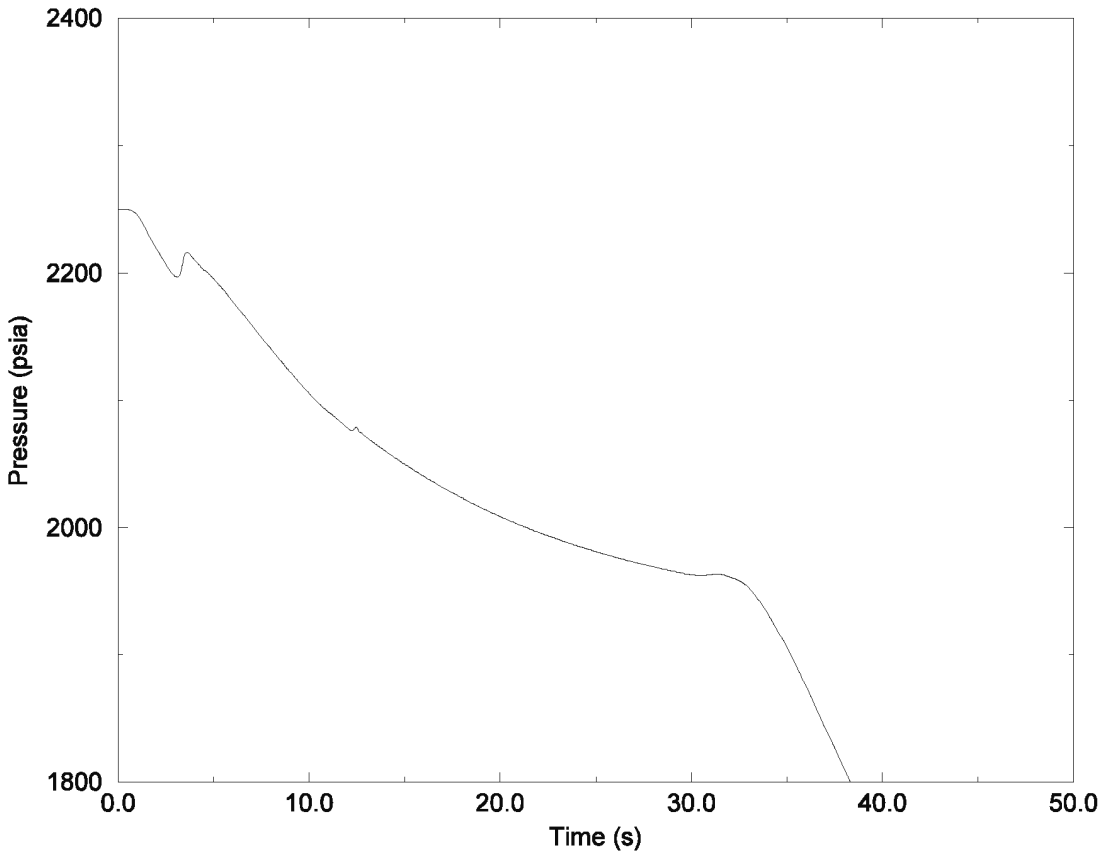

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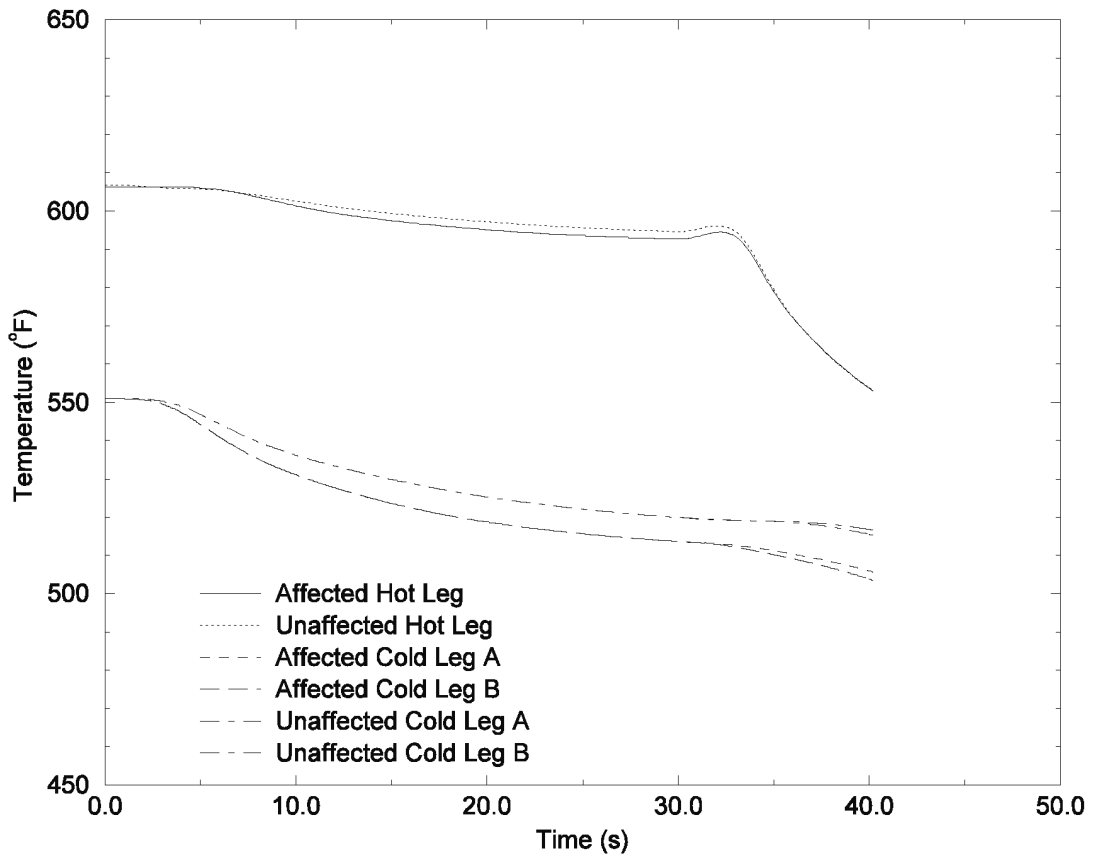
Figure 15.1.5-10
Pre-Trip Main Steamline Break (AREVA):
Pressurizer Pressure vs. Time



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ST. LUCIE PLANT UNIT 2

Figure 15.1.5-11
Pre-Trip Main Steamline Break (AREVA):
RCS Loop Temperatures vs. Time

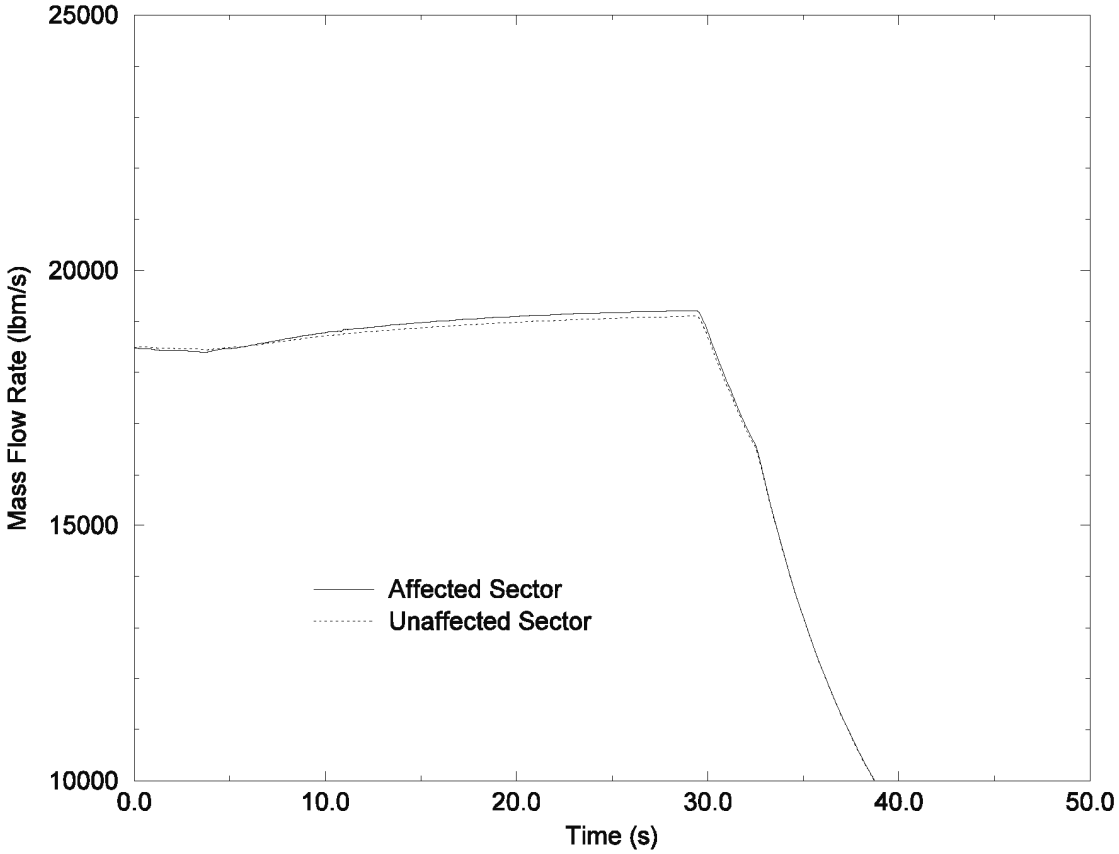

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Figure 15.1.5-12
Pre-Trip Main Steamline Break (AREVA):
Core Inlet Flow Rates vs. Time

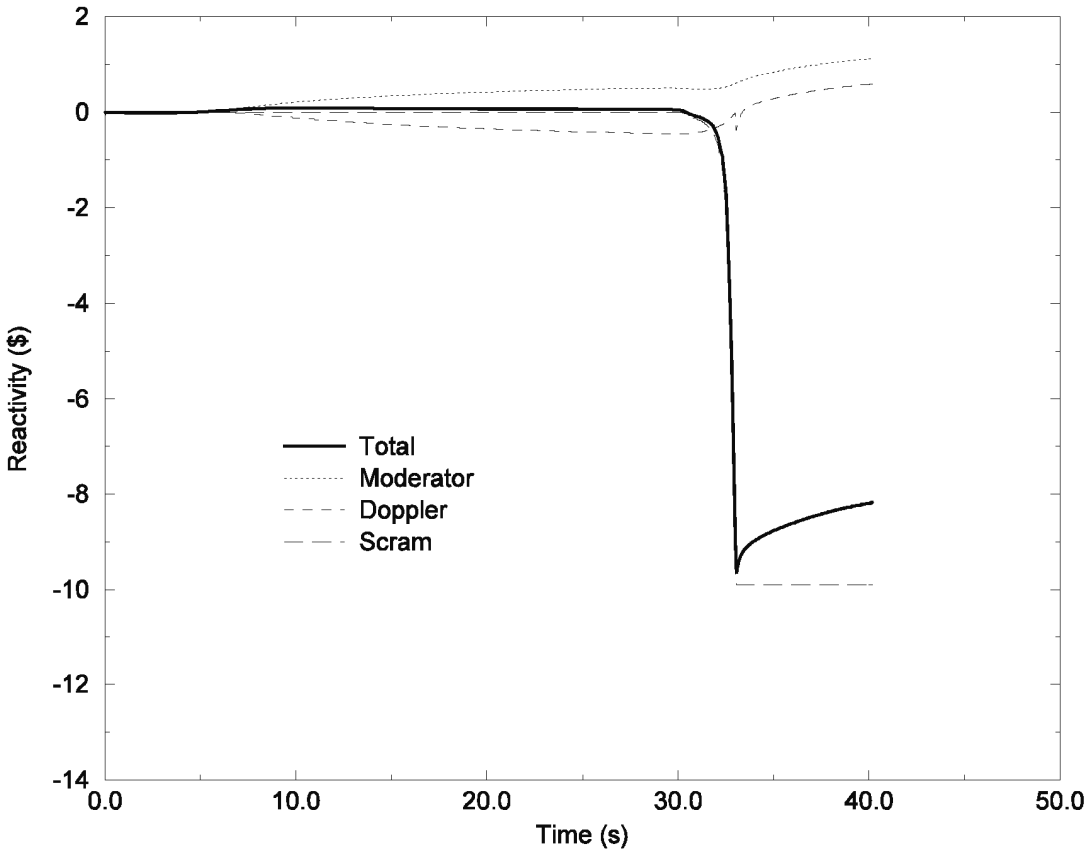

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Figure 15.1.5-13
Pre-Trip Main Steamline Break (AREVA):
Reactivity Feedback vs. Time

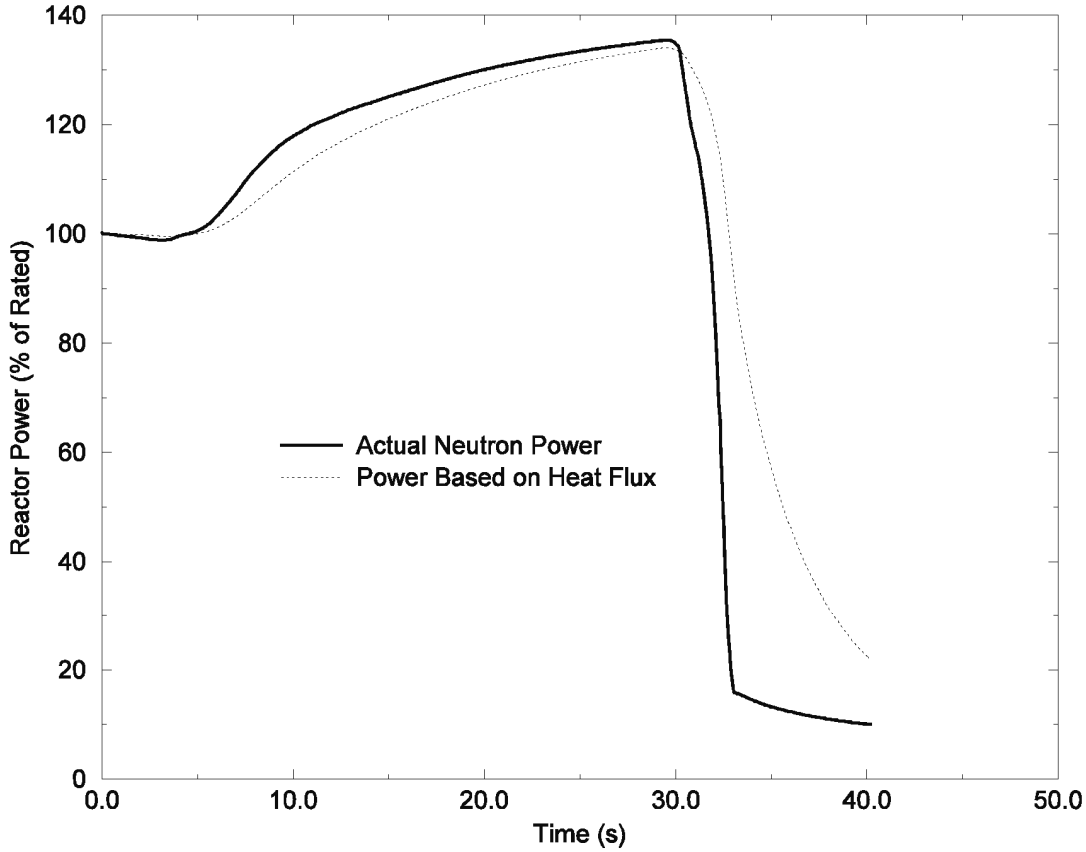

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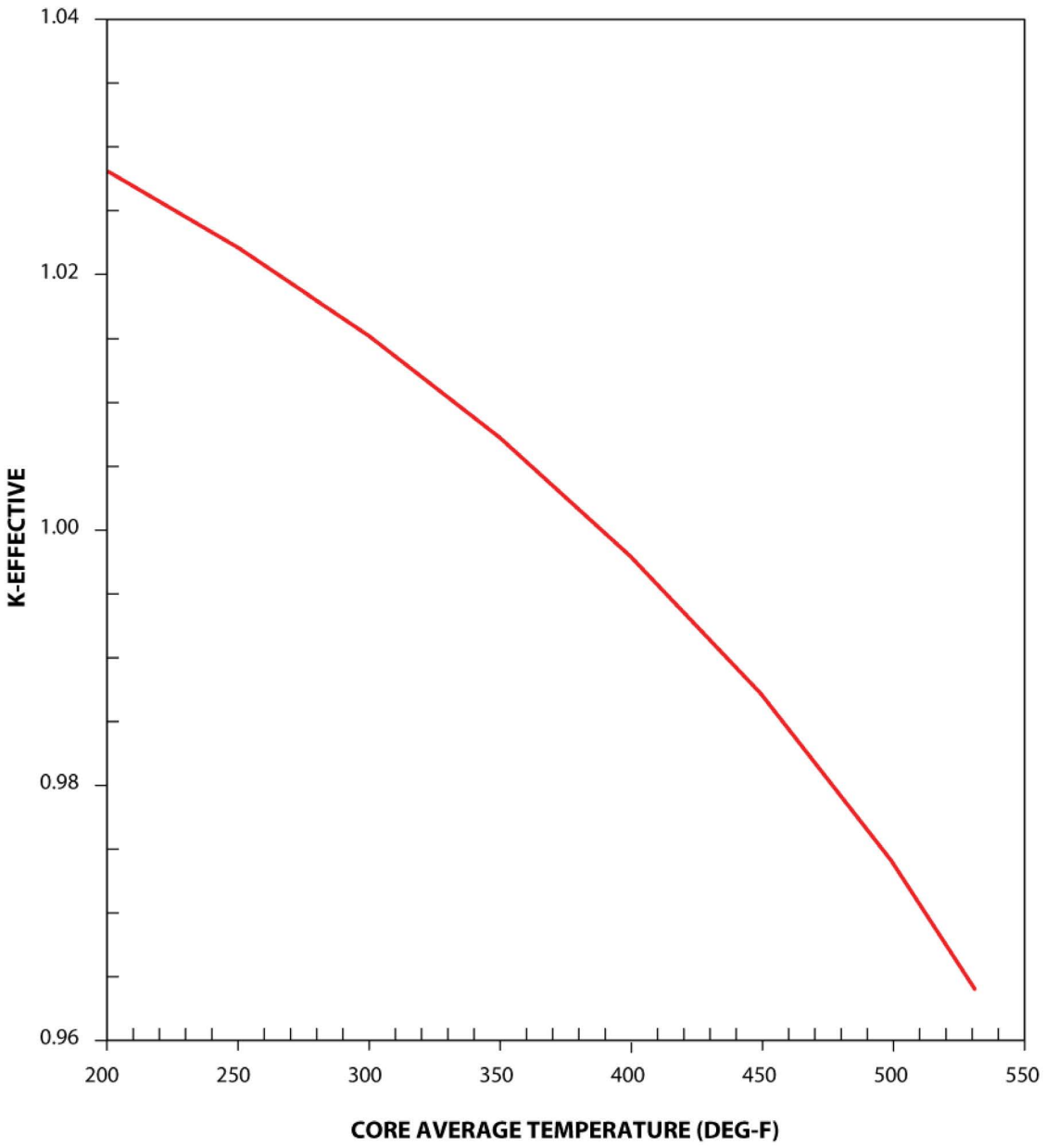
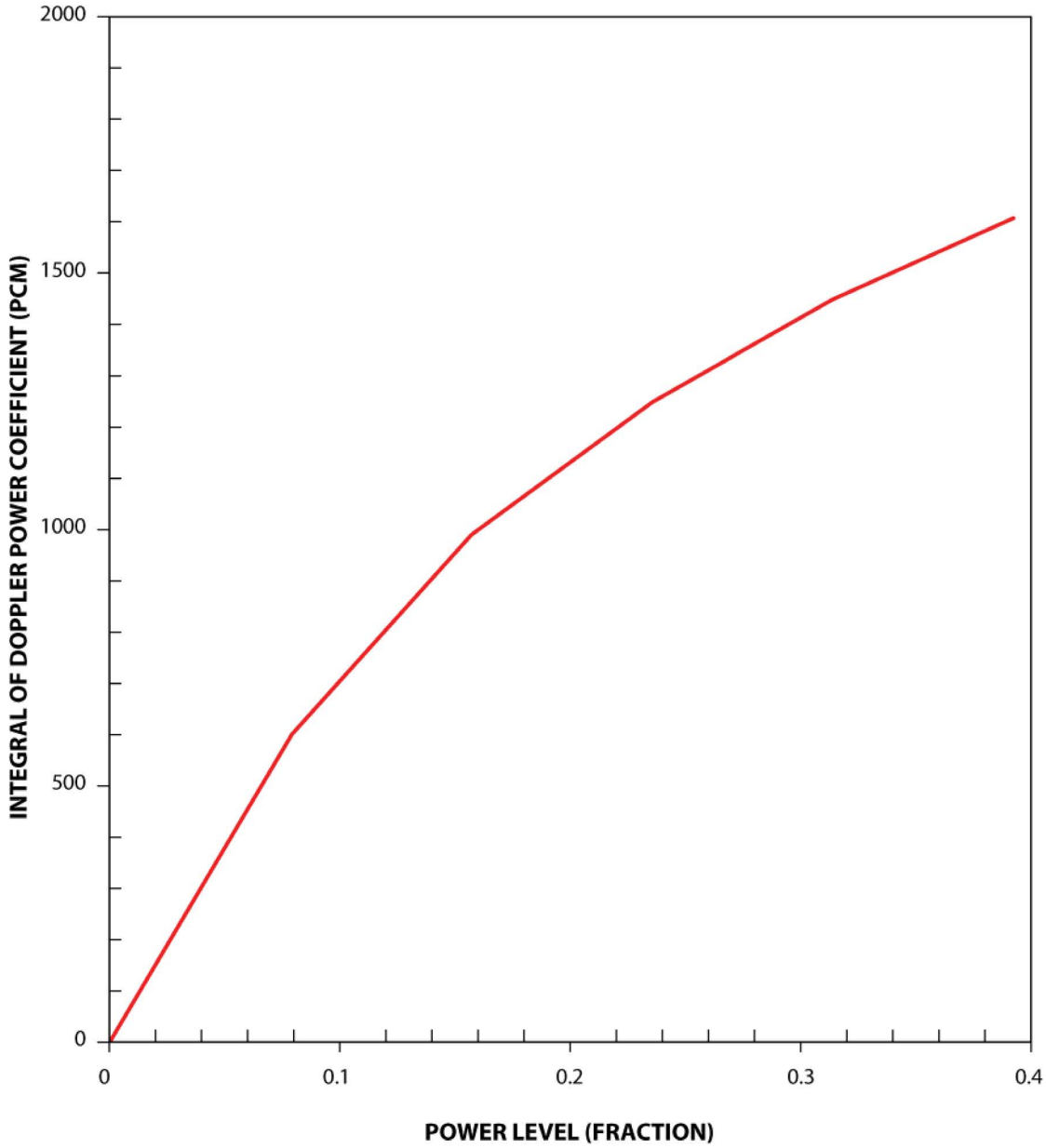
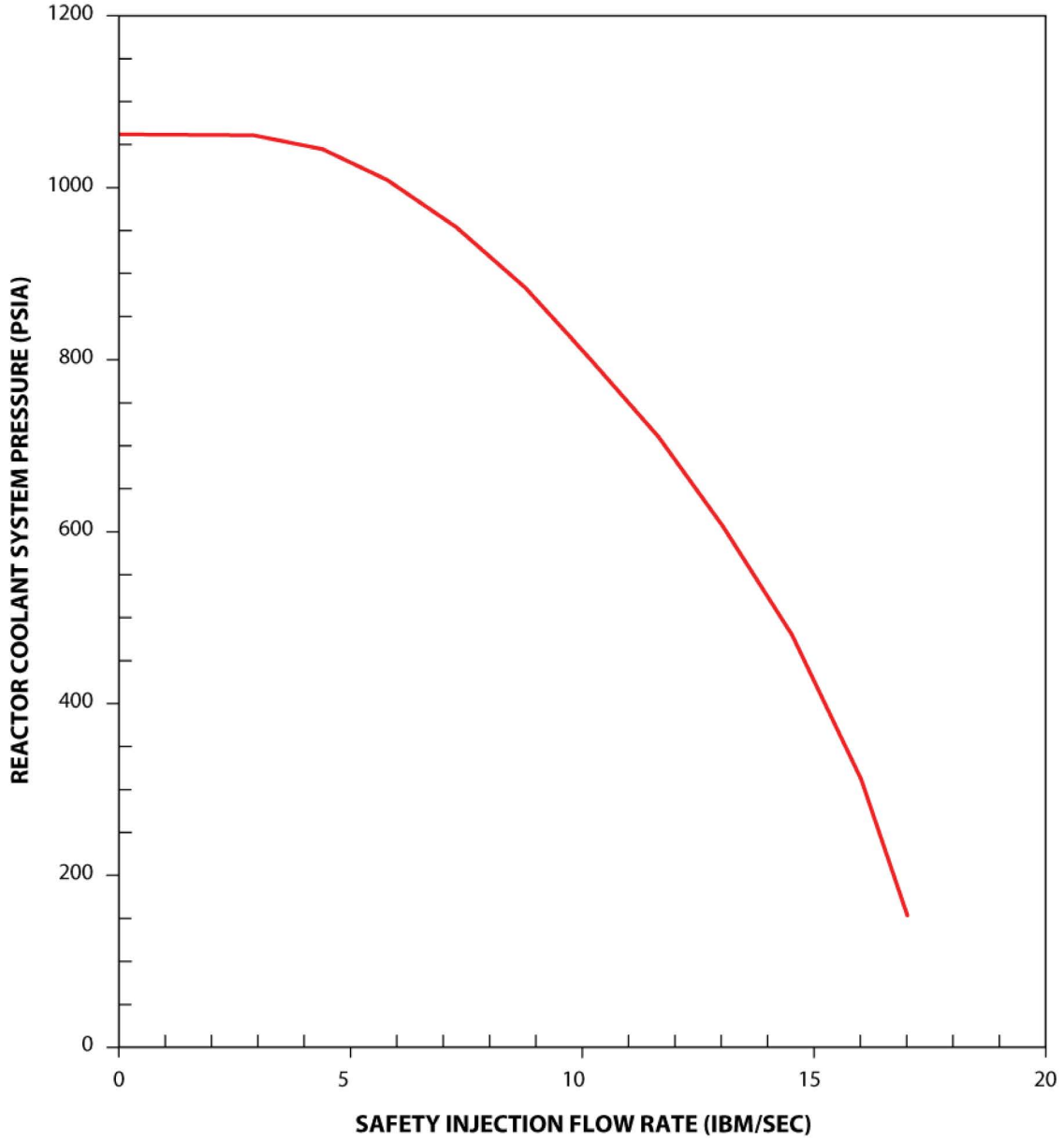
Figure 15.1.5-14
Pre-Trip Main Steamline Break (AREVA):
Reactor Power vs. Time



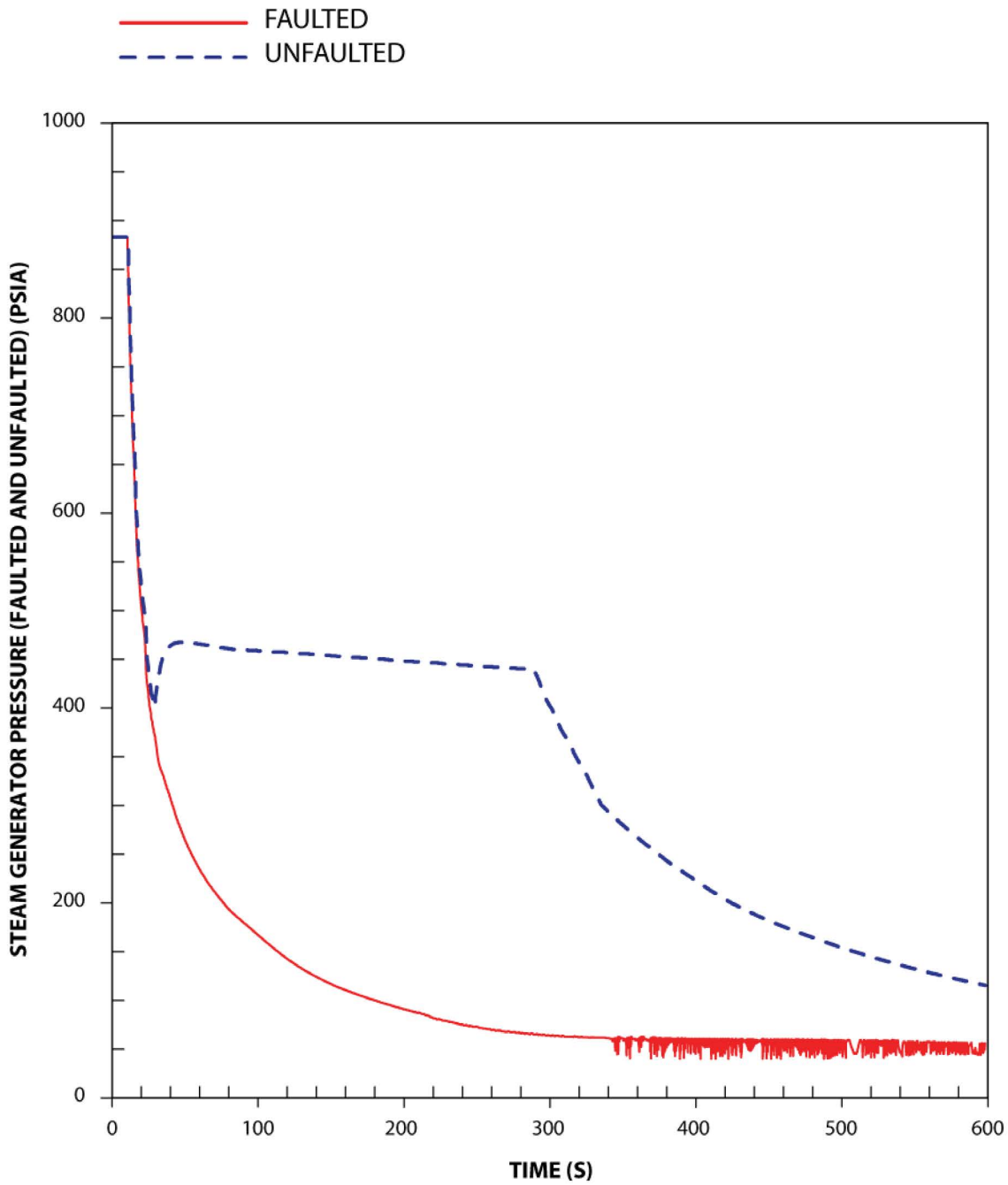
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-1 Post-Trip Main Steamline Break Variation of K_{eff} with Core Temperature (3.6%Δk SDM, 900 psia)



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-2 Post-Trip Main Steamline Break Stuck CEA Doppler Power Feedback Integral of Doppler Power Coefficient vs. Power Level

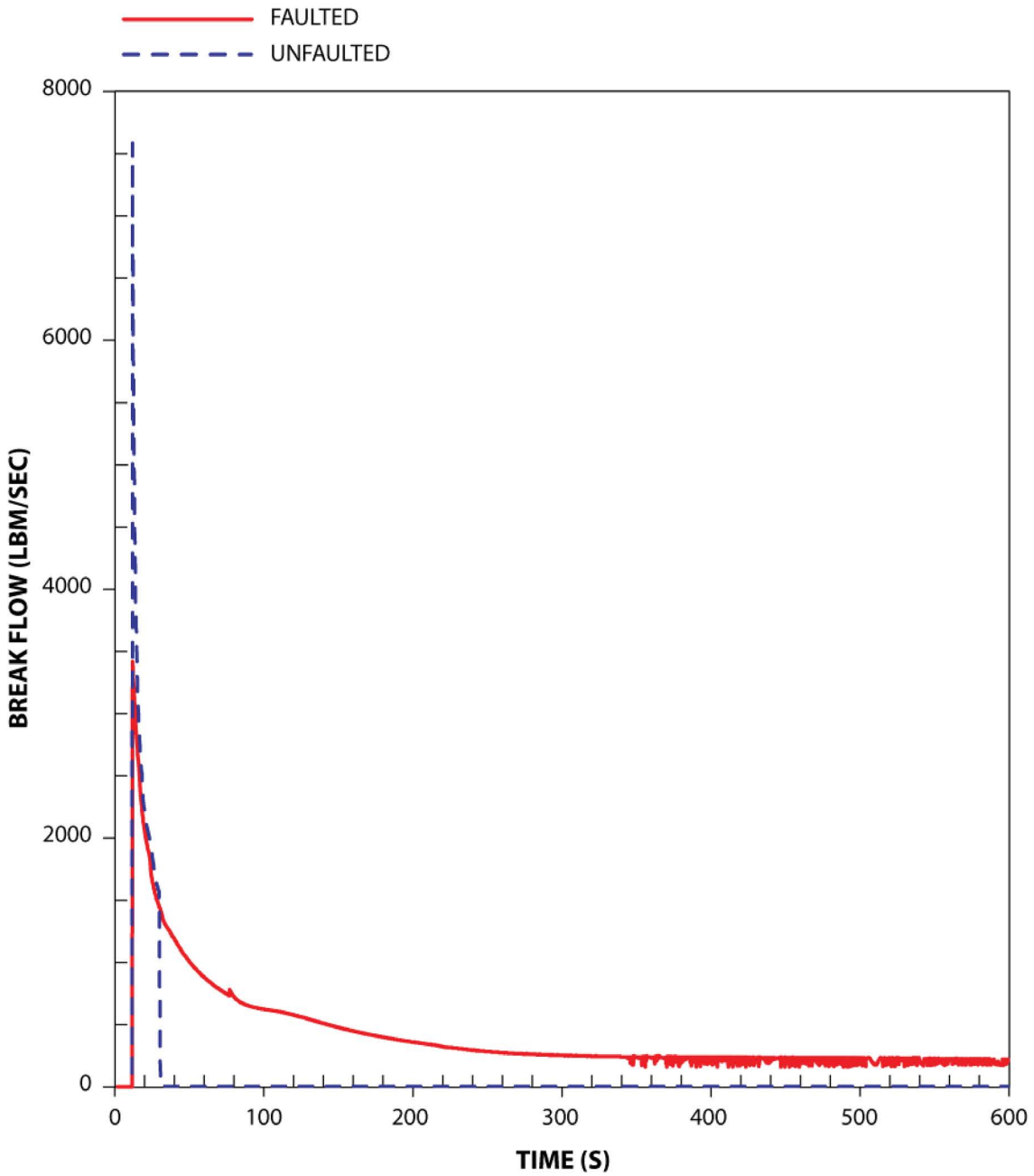


FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-3 Post-Trip Main Steamline Break Safety Injection Curve



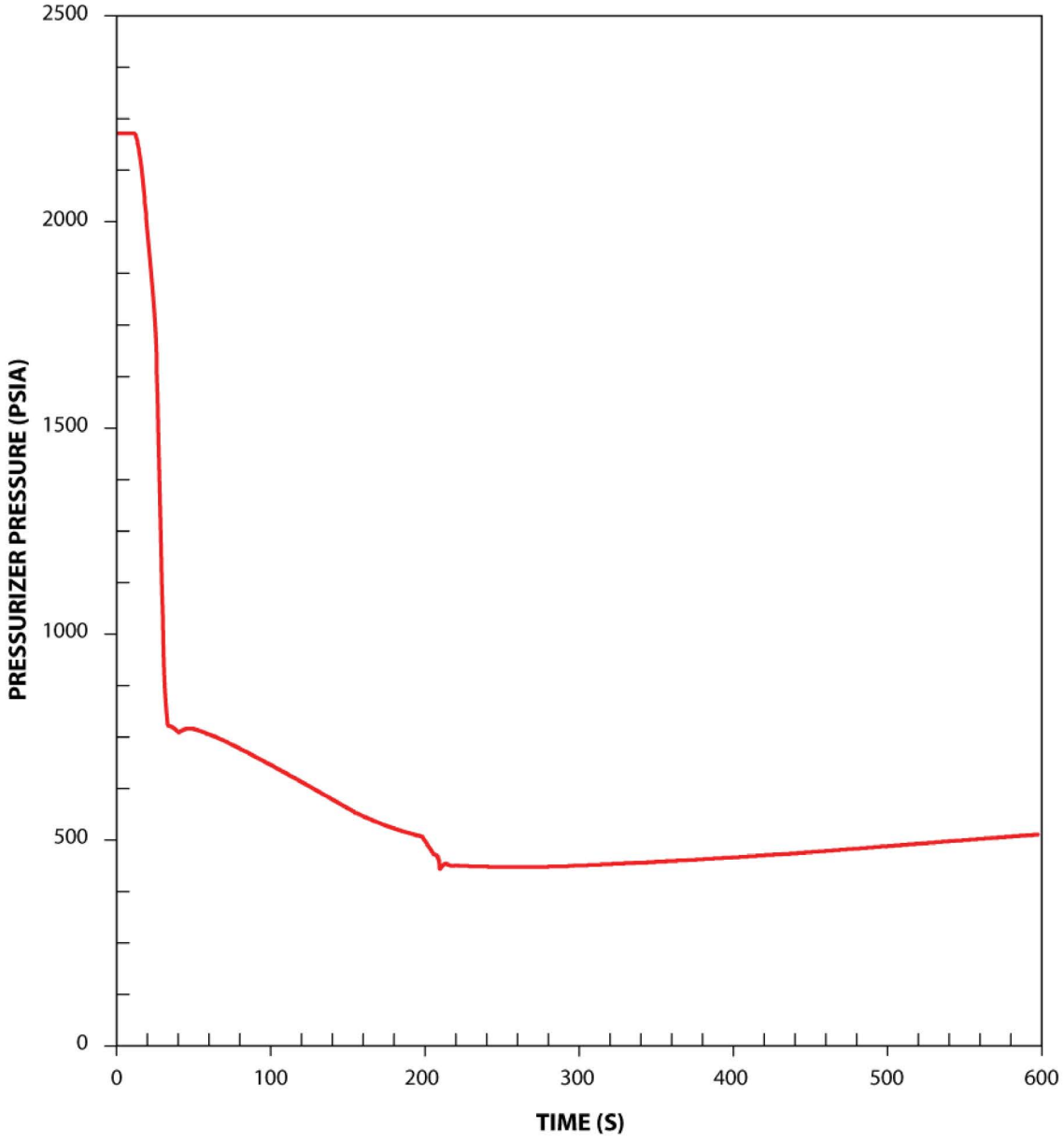
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-4 Post-Trip Main Steamline Break Steam Generator Steam Pressure vs. Time



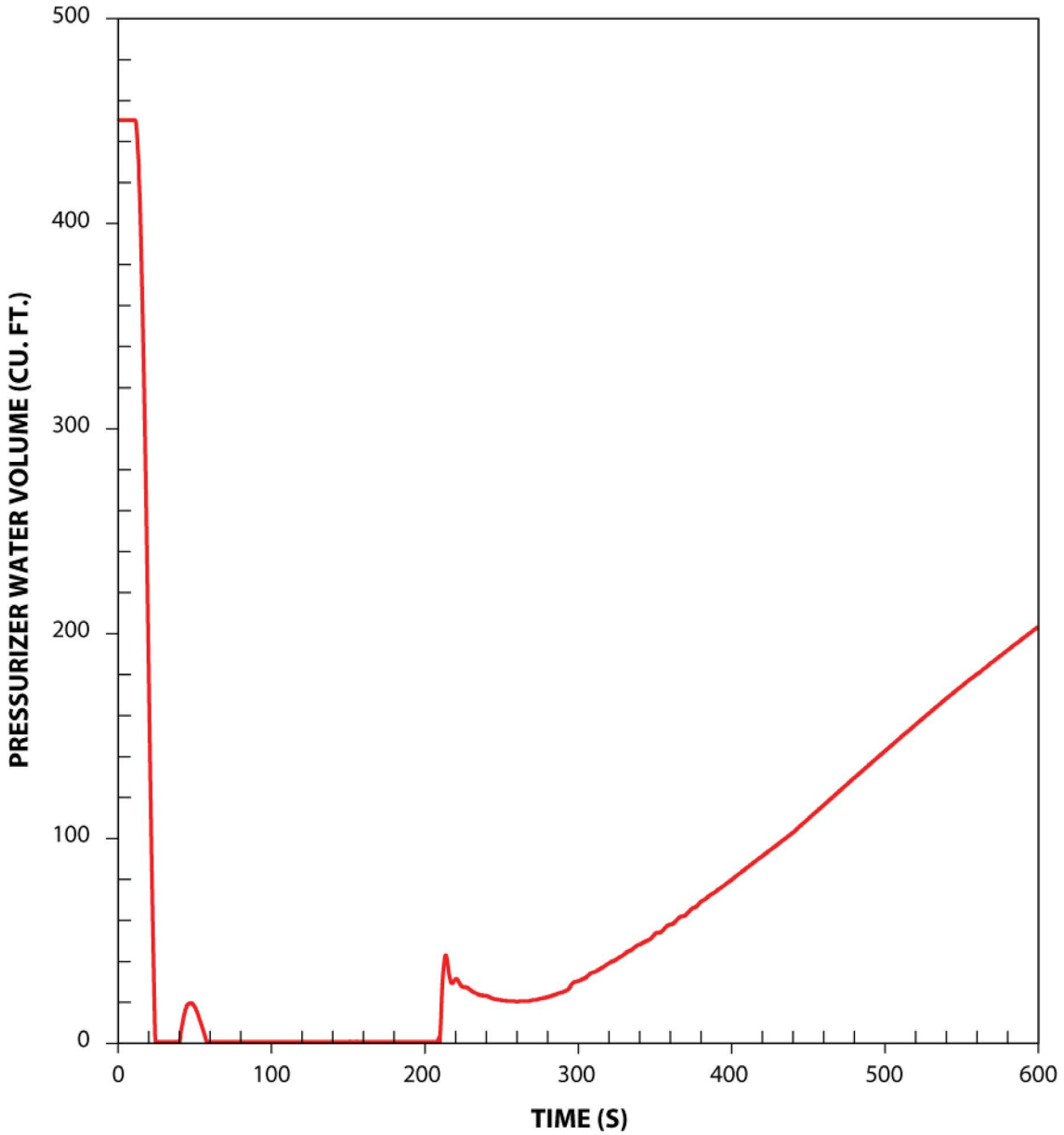
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-5 Post-Trip Main Steamline Break Break Flow Rate vs. Time



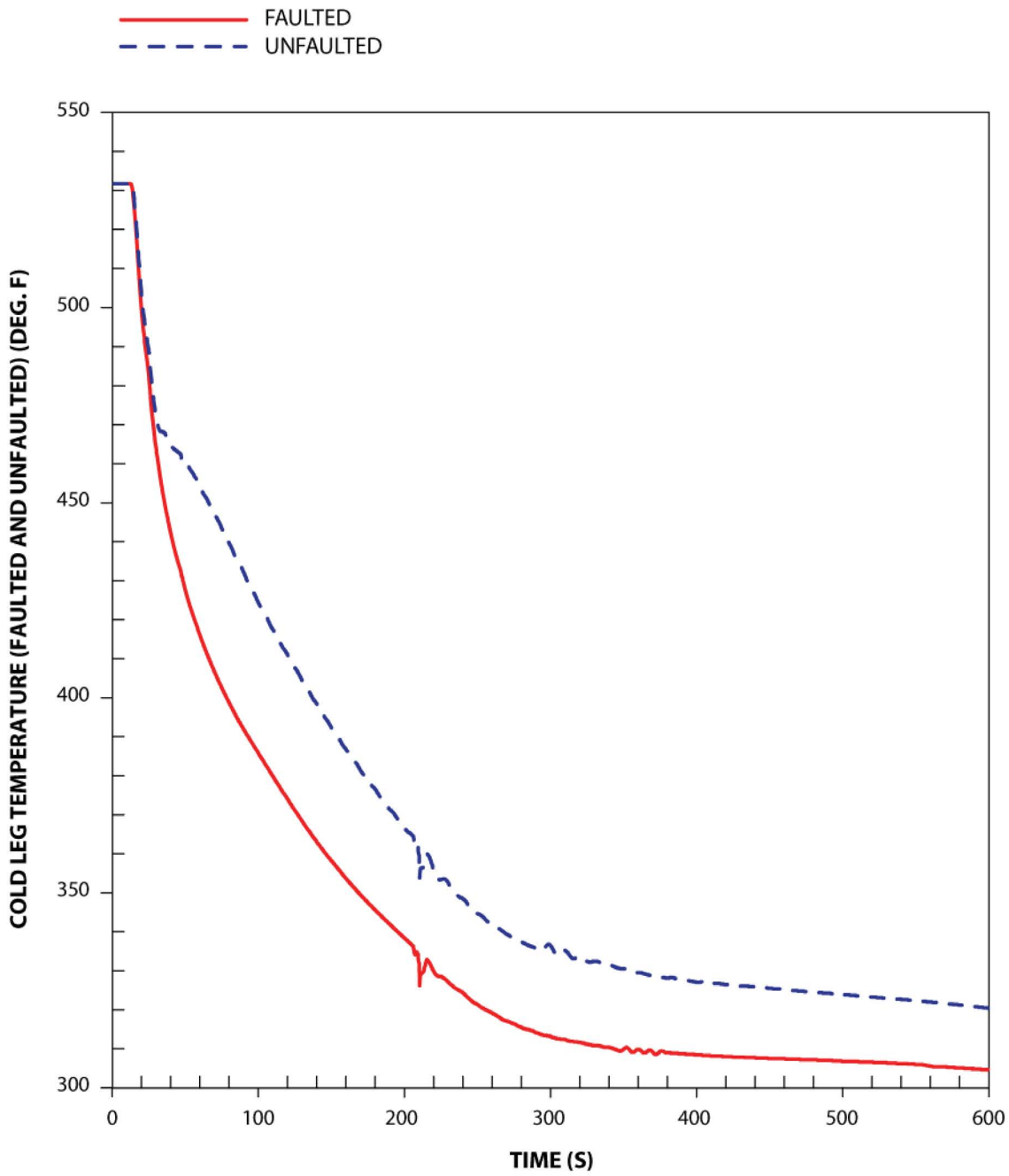
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-6 Post-Trip Main Steamline Break Pressurizer Pressure vs. Time



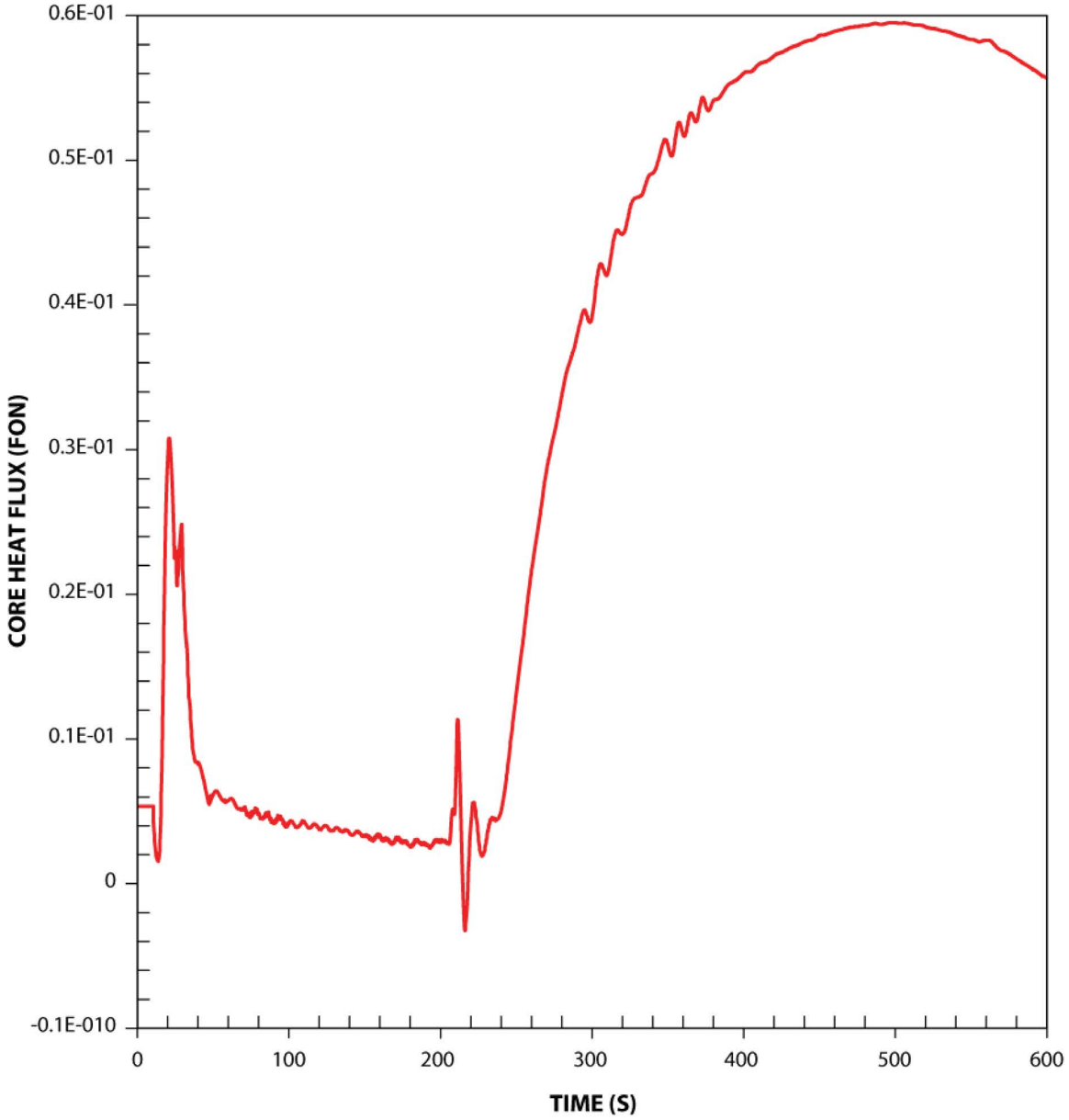
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-7 Post-Trip Main Steamline Break Pressurizer Water Volume vs. Time



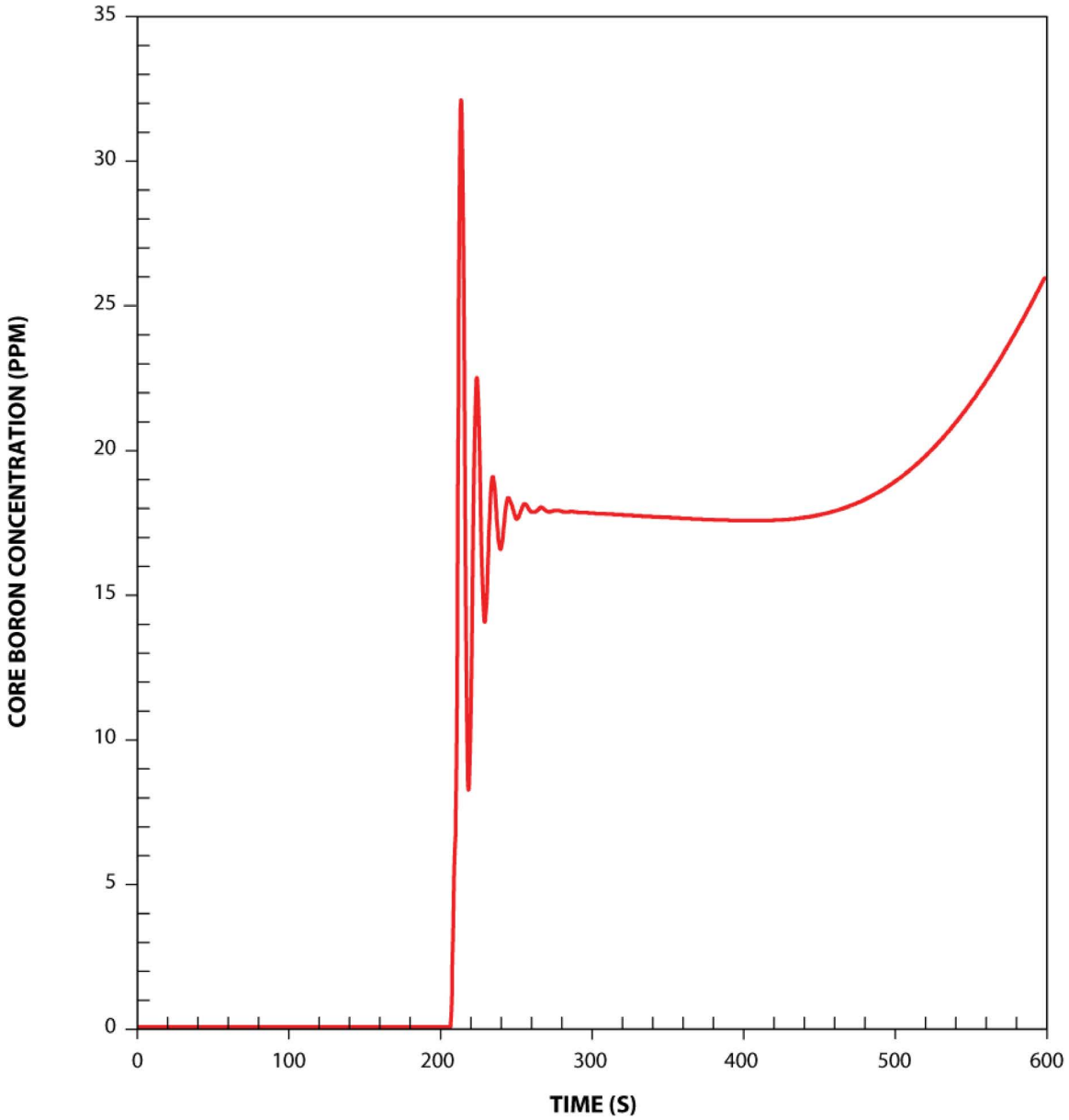
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-8 Post-Trip Main Steamline Break Cold Leg Temperature vs. Time



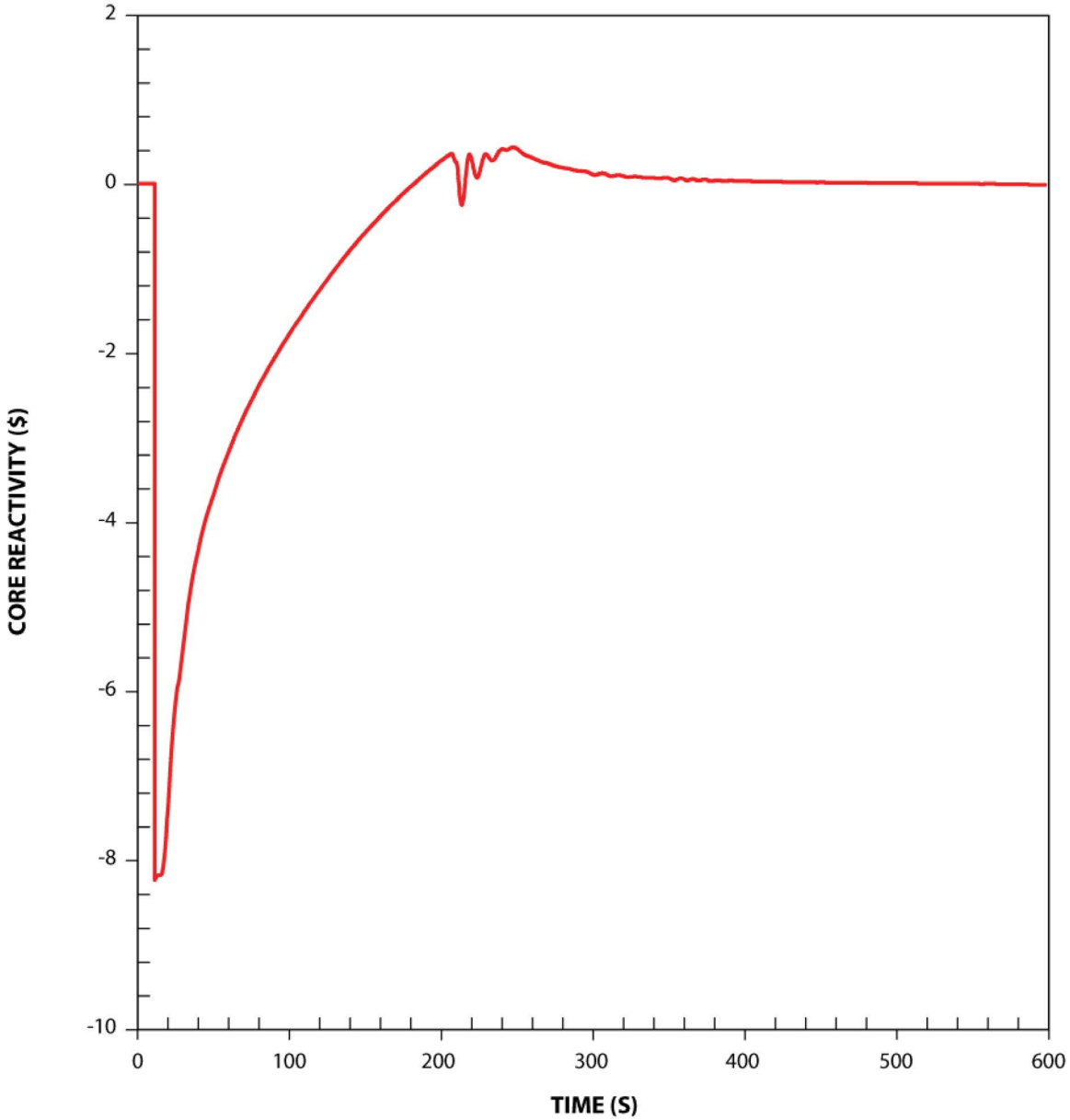
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-9 Post-Trip Main Steamline Break Core Heat Flux vs. Time



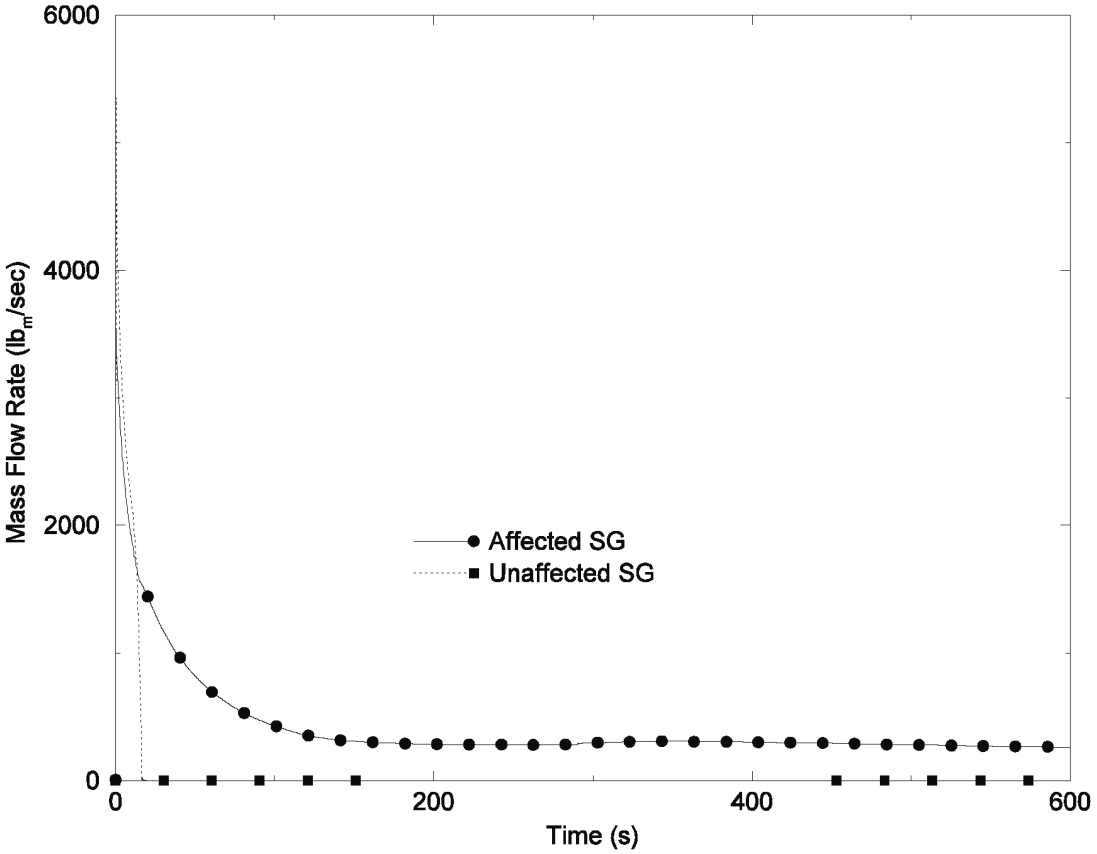
Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-10 Post-Trip Main Steamline Break Core Boron Concentration vs. Time



Note: Figure includes a 10 second steady state time period.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.1.6-11 Post-Trip Main Steamline Break Reactivity vs. Time



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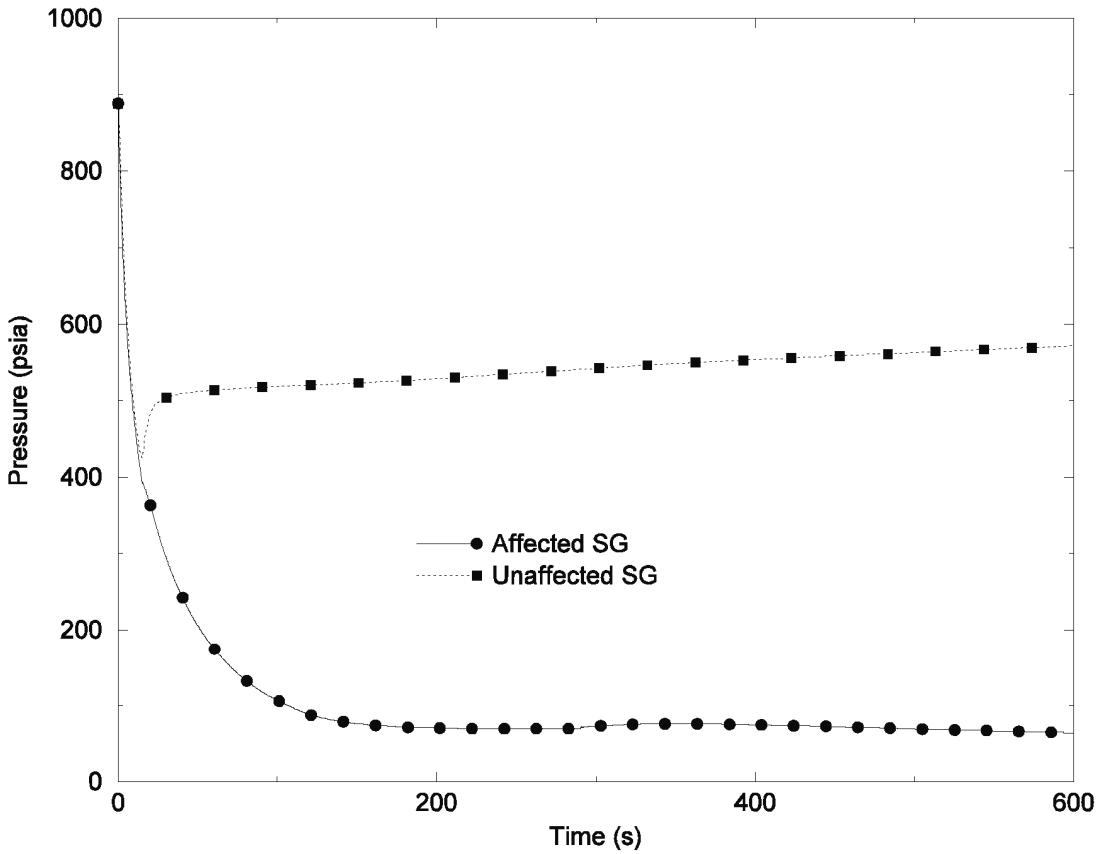
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-12
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Break Flow Rates vs. Time (AREVA)



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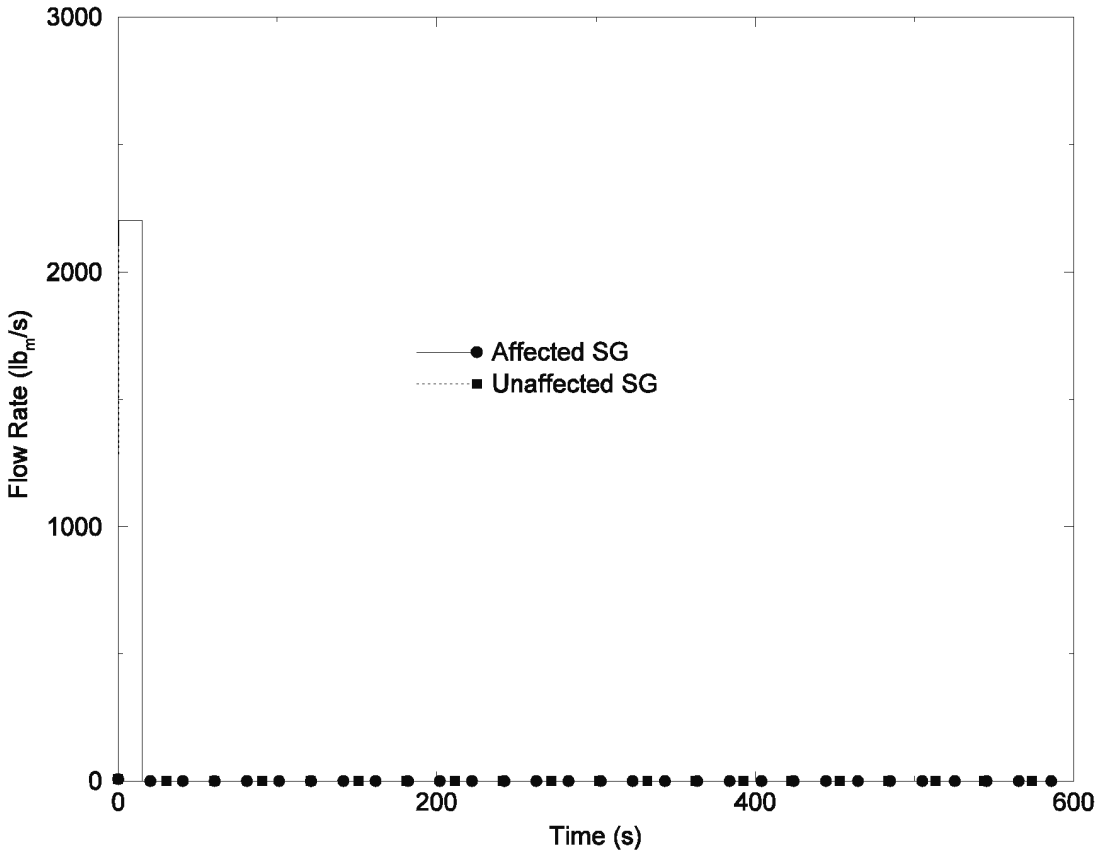
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-13
Post-Trip Main Steamline Break (HZP Offsite Power Available): Steam Generator Pressures vs. Time (AREVA)



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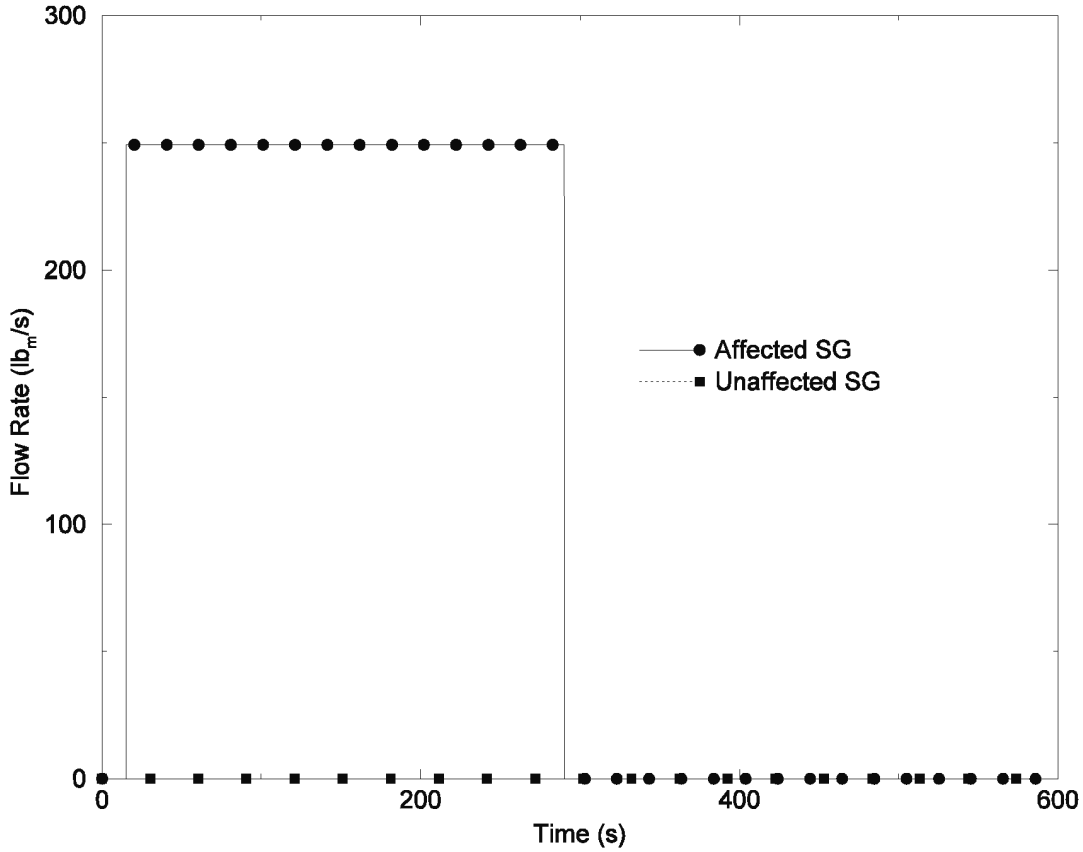
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-14
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
MFW Flow Rates vs. Time (AREVA)



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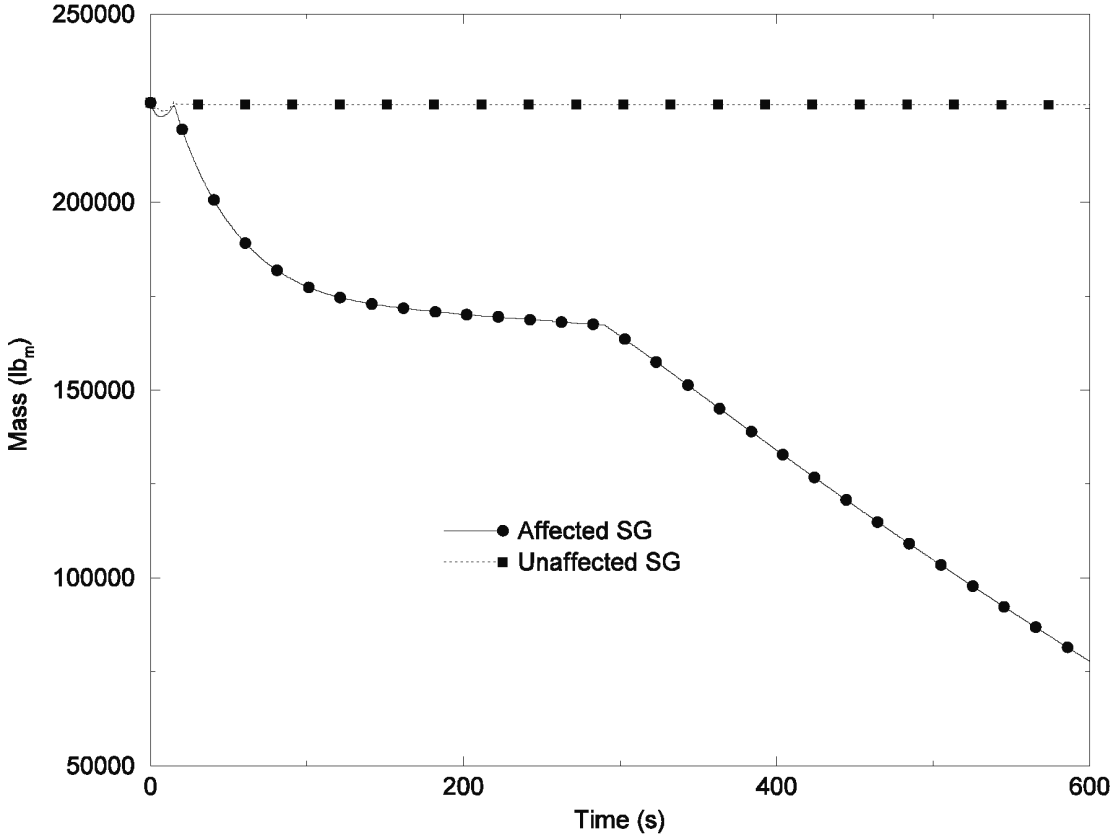
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-15
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
AFW Flow Rates vs. Time (AREVA)



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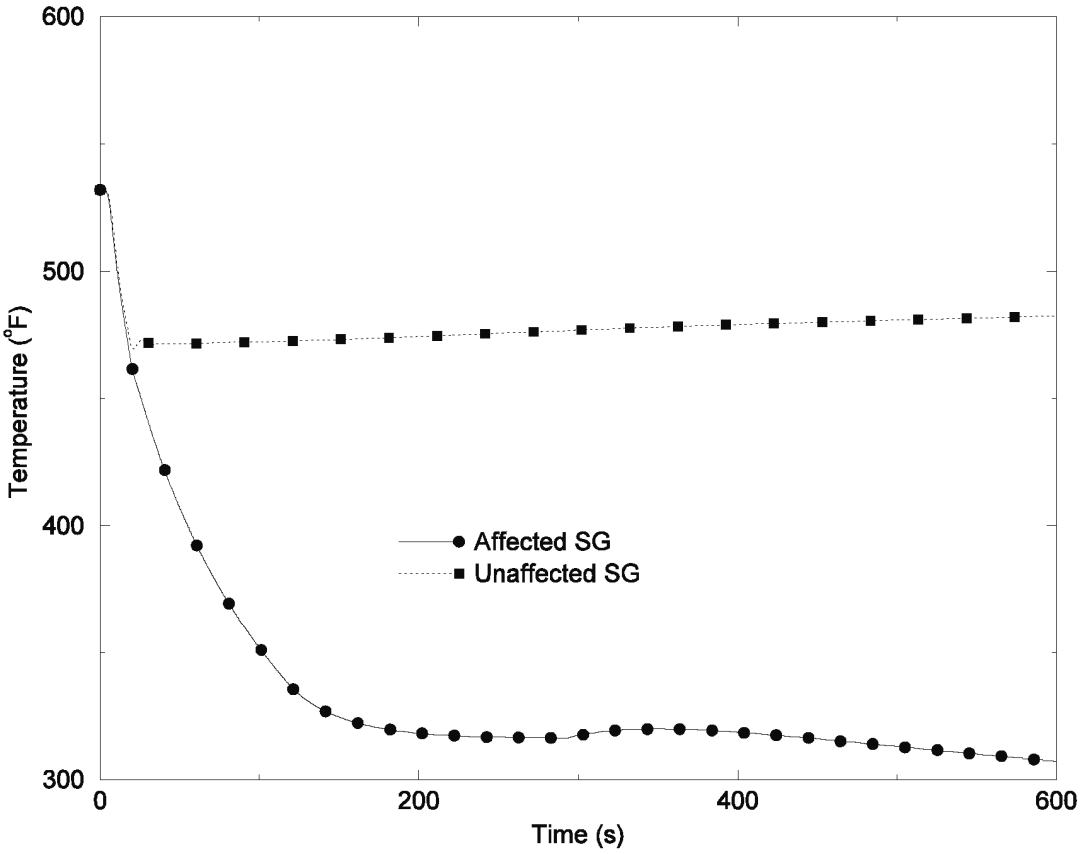
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-16
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Steam Generator Mass Inventories vs. Time
(AREVA)



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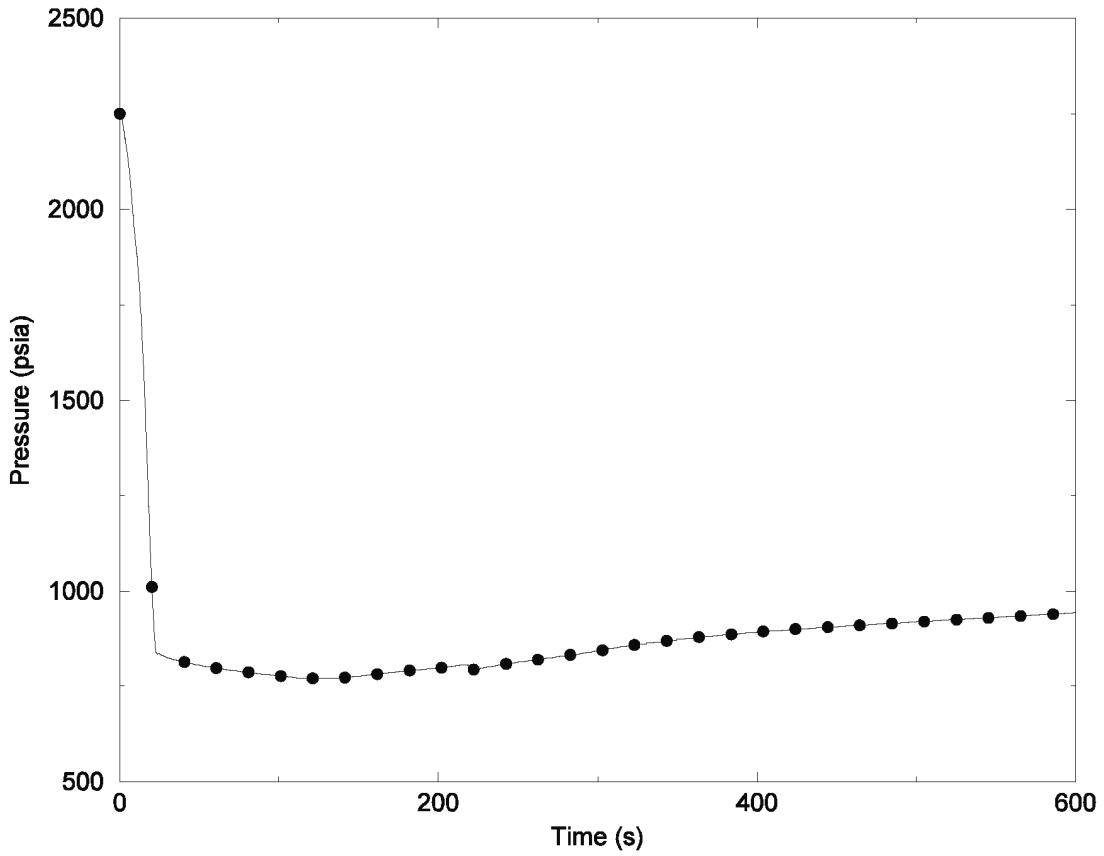
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-17
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Core Inlet Fluid Temperatures vs. Time
(AREVA)



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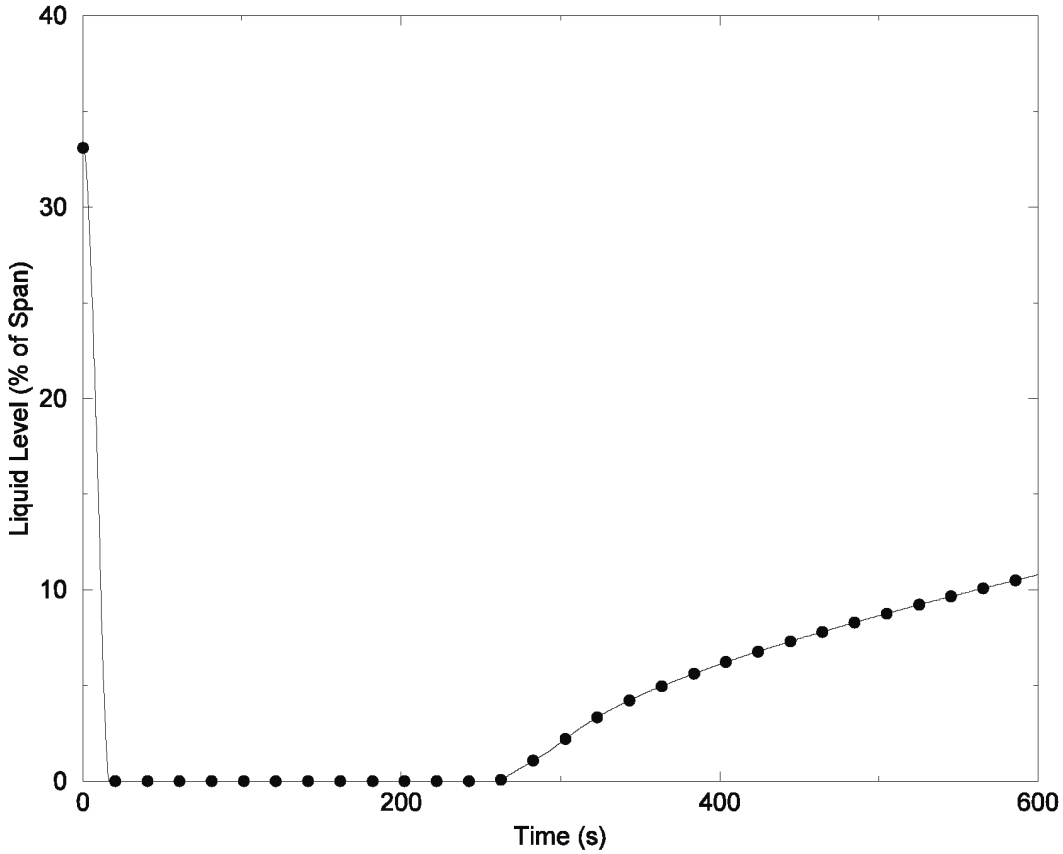
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-18
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Pressurizer Pressure vs. Time (AREVA)



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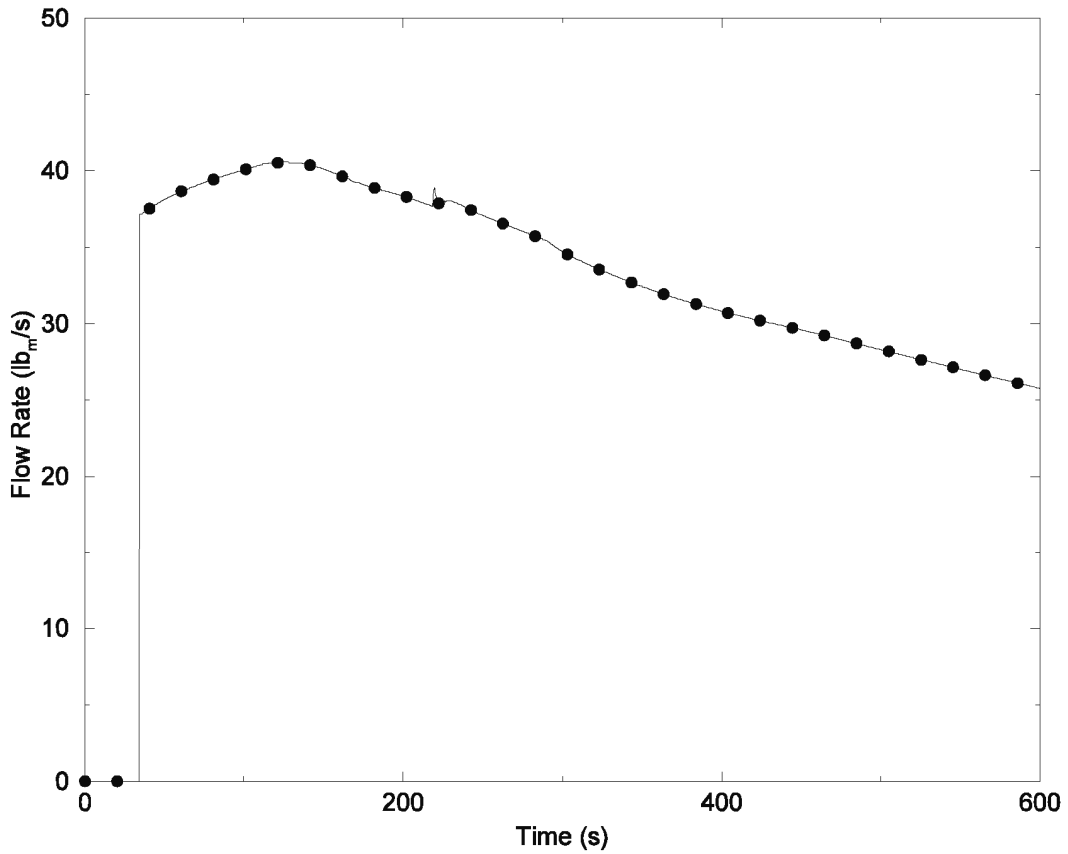
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-19
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Pressurizer Liquid Level vs. Time (AREVA)



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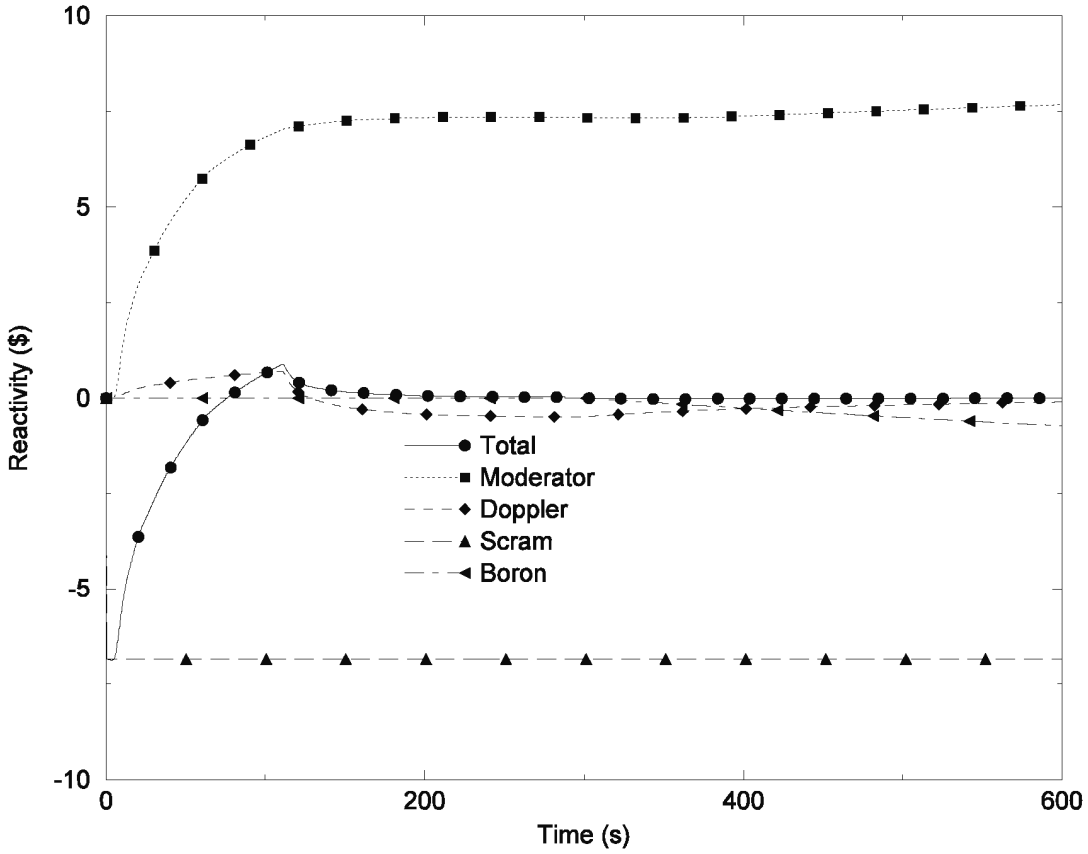
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-20
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Total HPSI Flow Rate vs. Time (AREVA)



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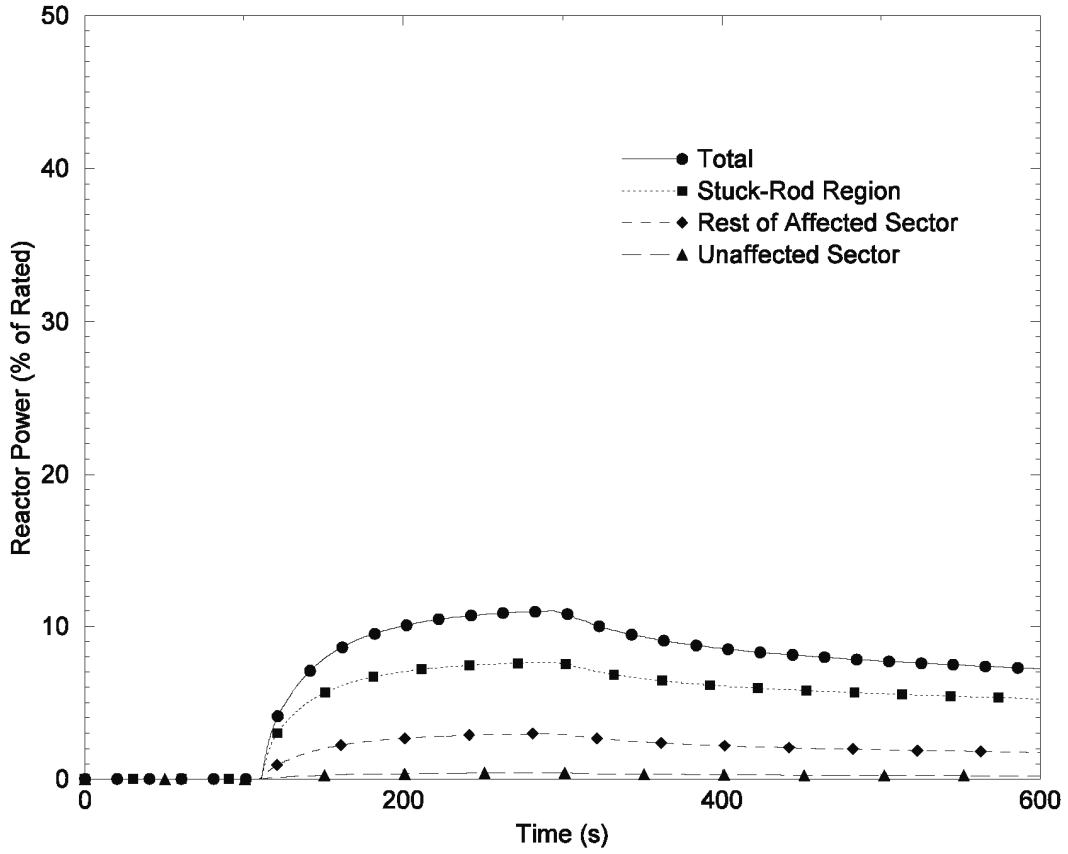
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-21
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Reactivity Feedback vs. Time (AREVA)



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ST. LUCIE PLANT UNIT 2

Figure 15.1.6-22
Post-Trip Main Steamline Break
(HZP Offsite Power Available):
Reactor Power vs. Time (AREVA)

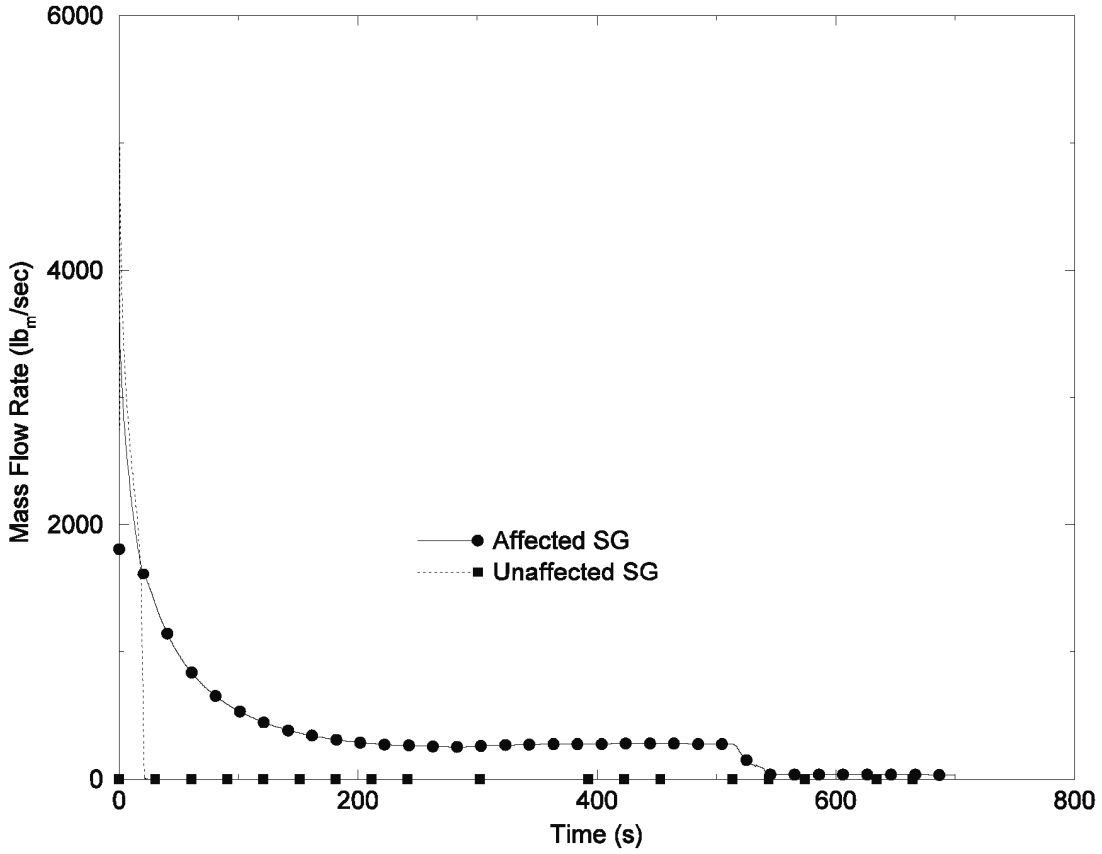

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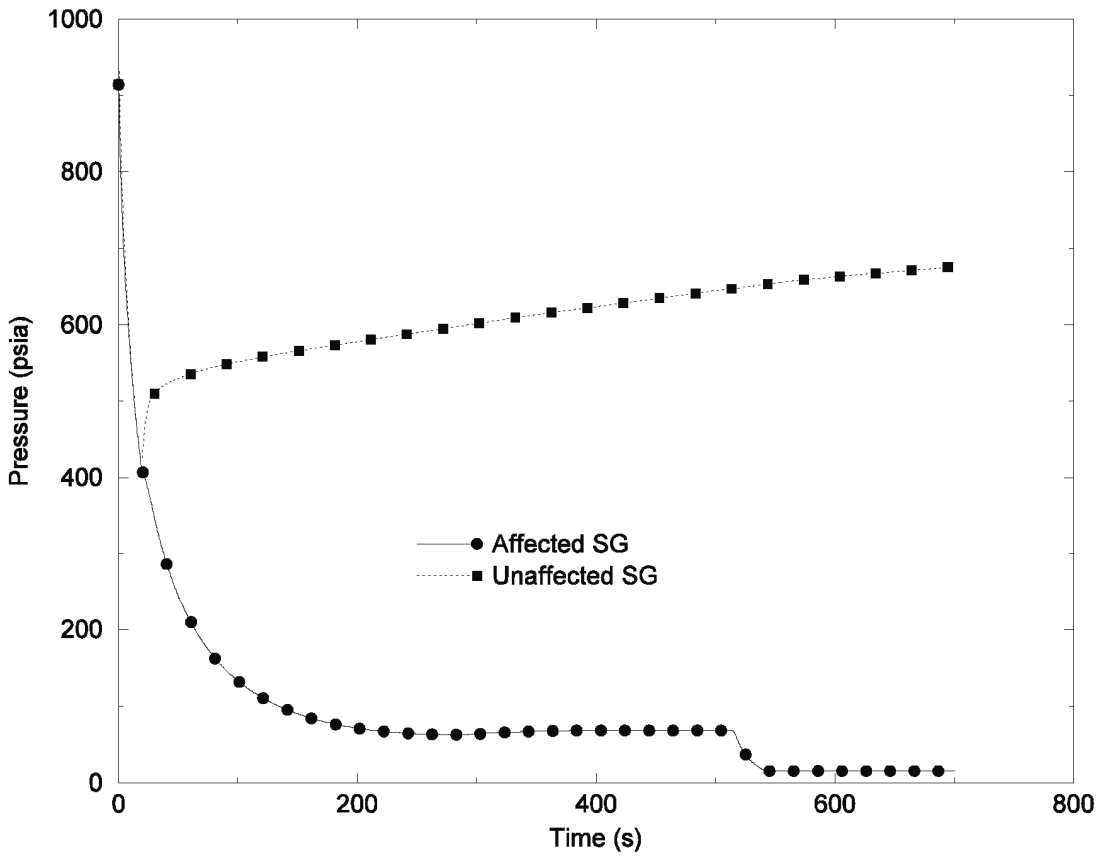
Figure 15.1.6-23
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Break Flow Rates vs. Time (AREVA)



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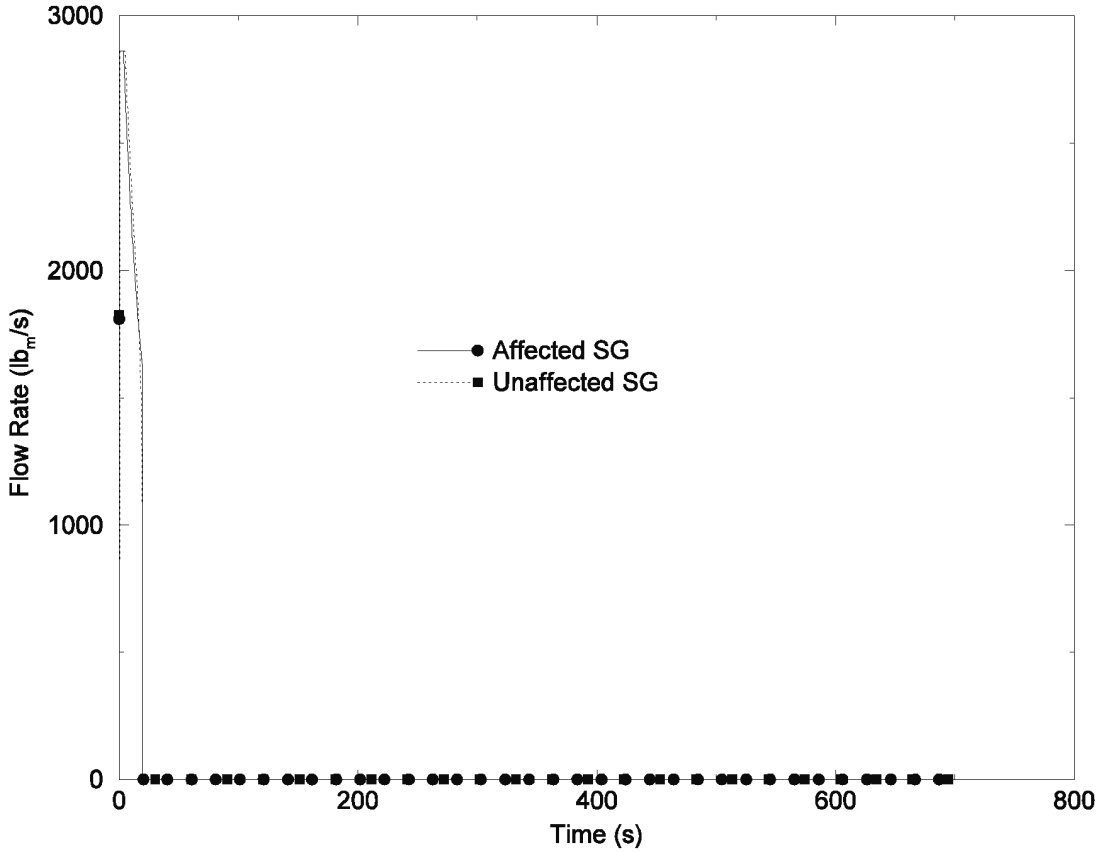
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-24
Post-Trip Main Steamline Break (HFP Offsite Power Available): Steam Generator Pressures vs. Time (AREVA)



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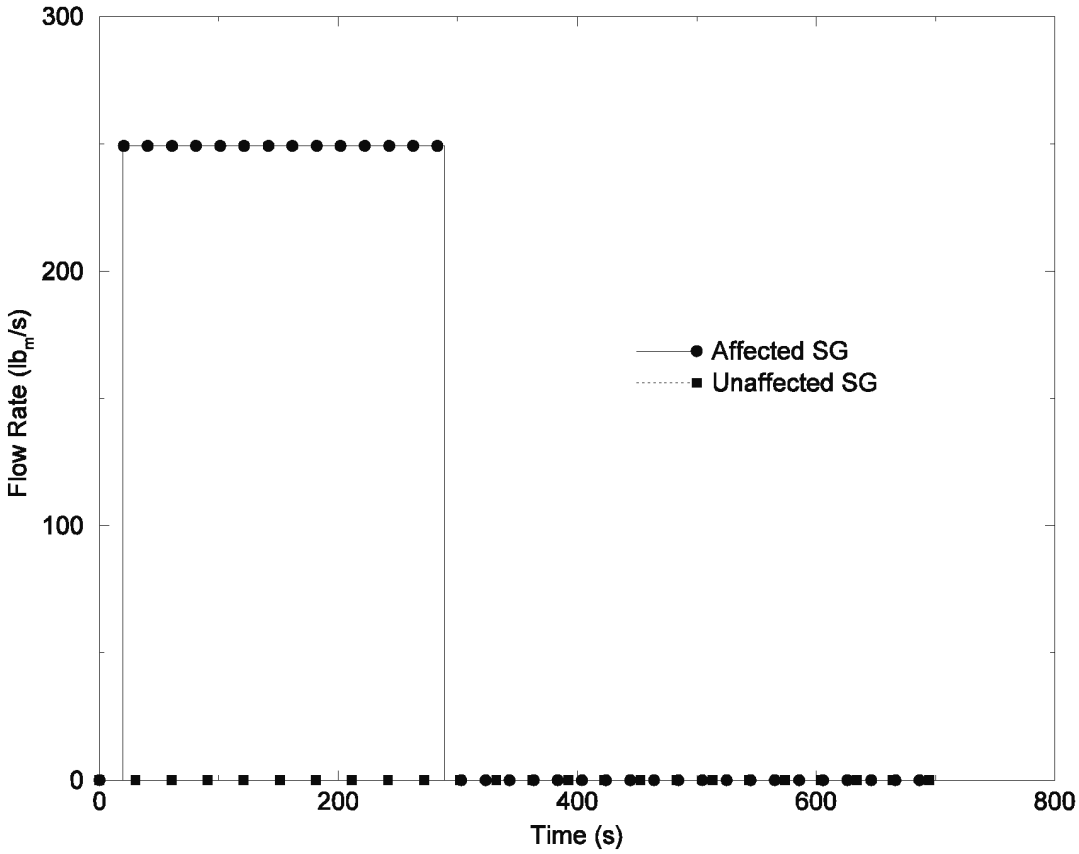
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-25
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
MFW Flow Rates vs. Time (AREVA)



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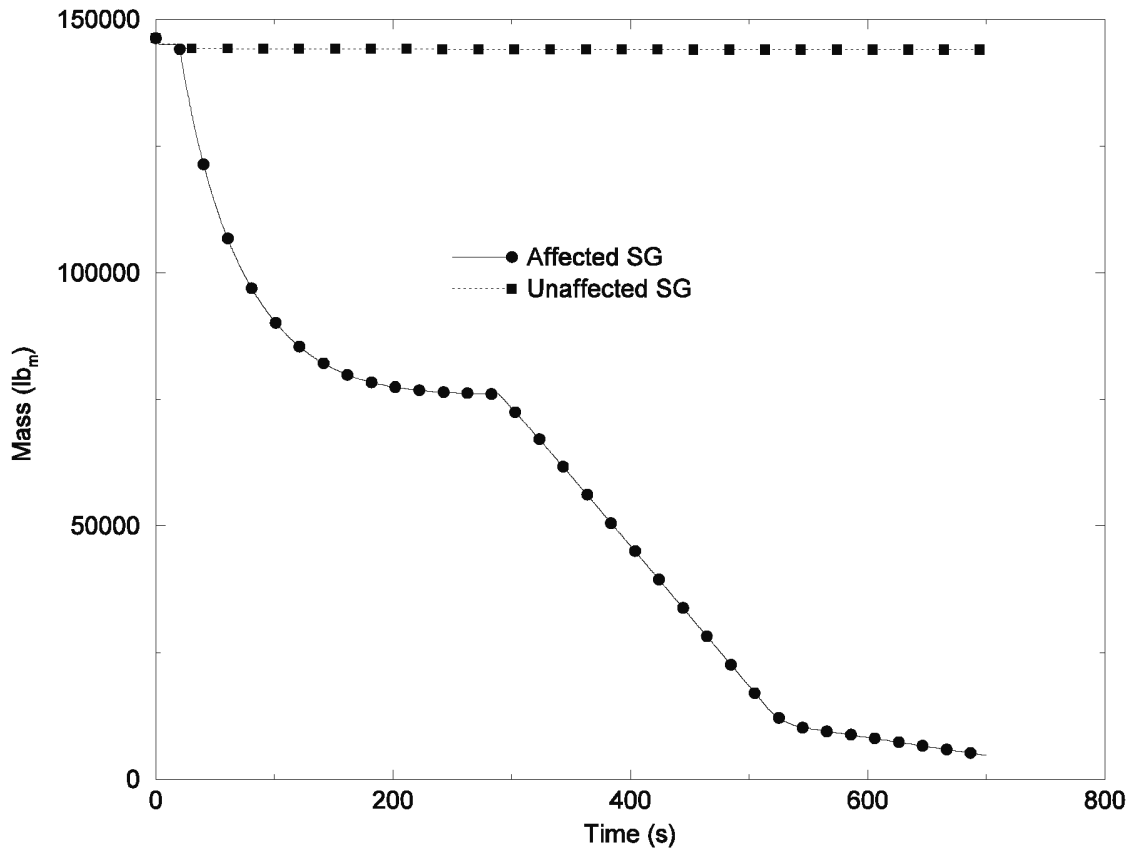
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-26
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
AFW Flow Rates vs. Time (AREVA)



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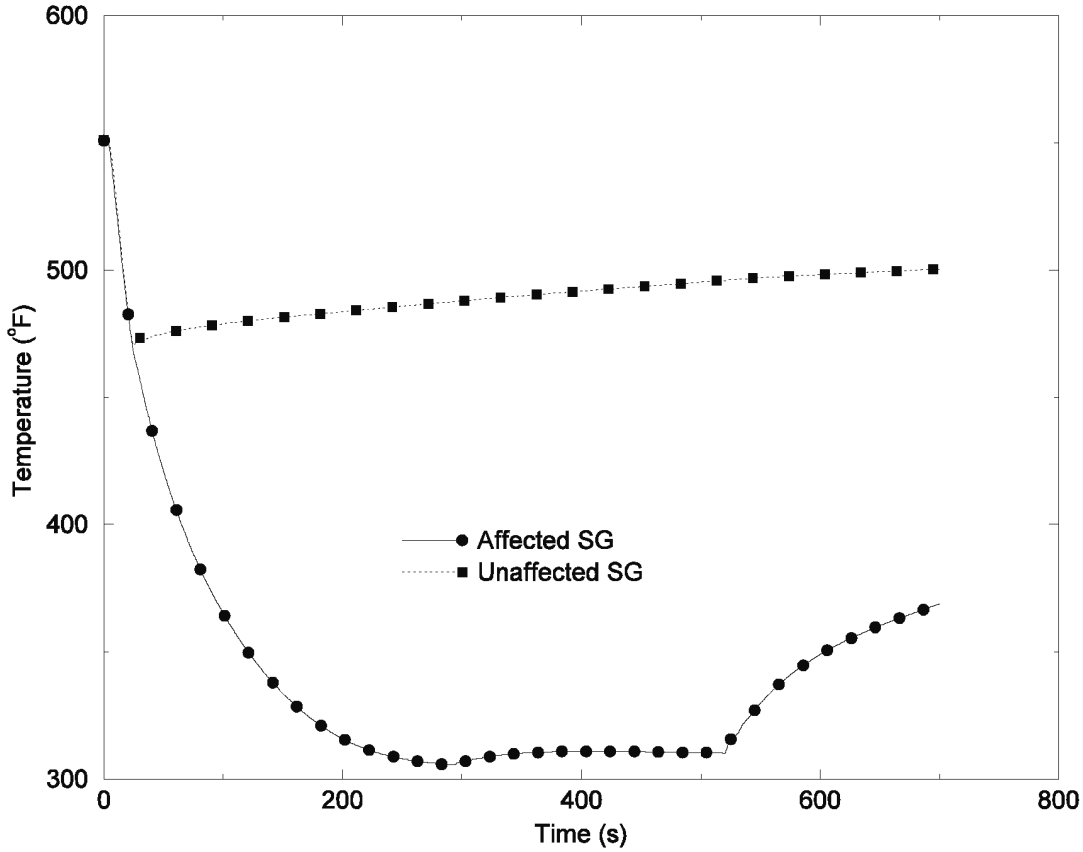
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-27
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Steam Generator Mass Inventories vs. Time
(AREVA)



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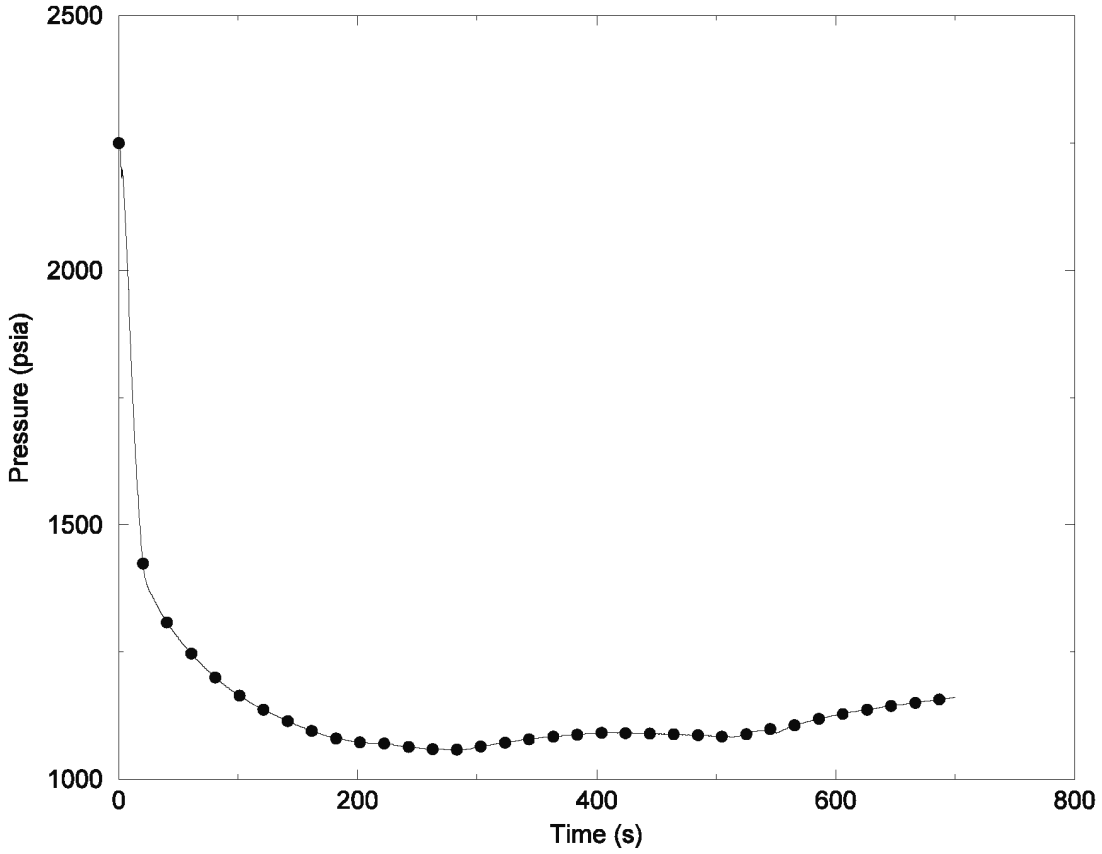
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-28
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Core Inlet Fluid Temperatures vs. Time
(AREVA)



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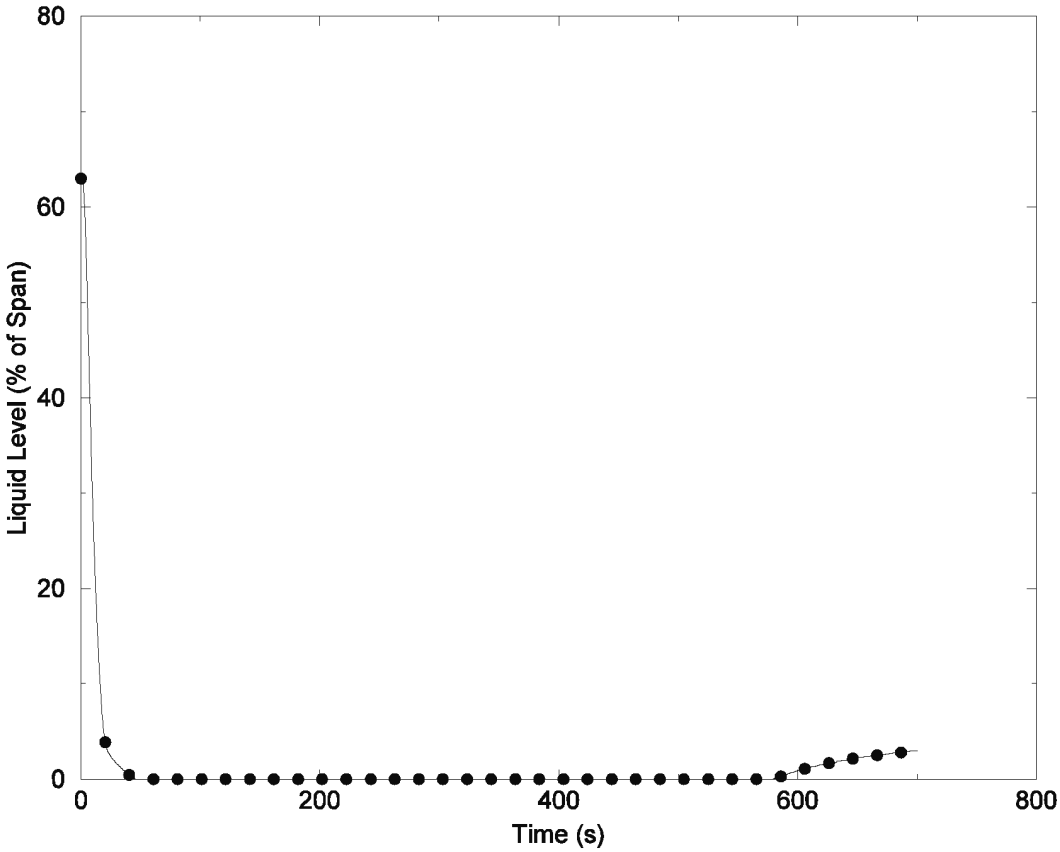
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-29
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Pressurizer Pressure vs. Time (AREVA)



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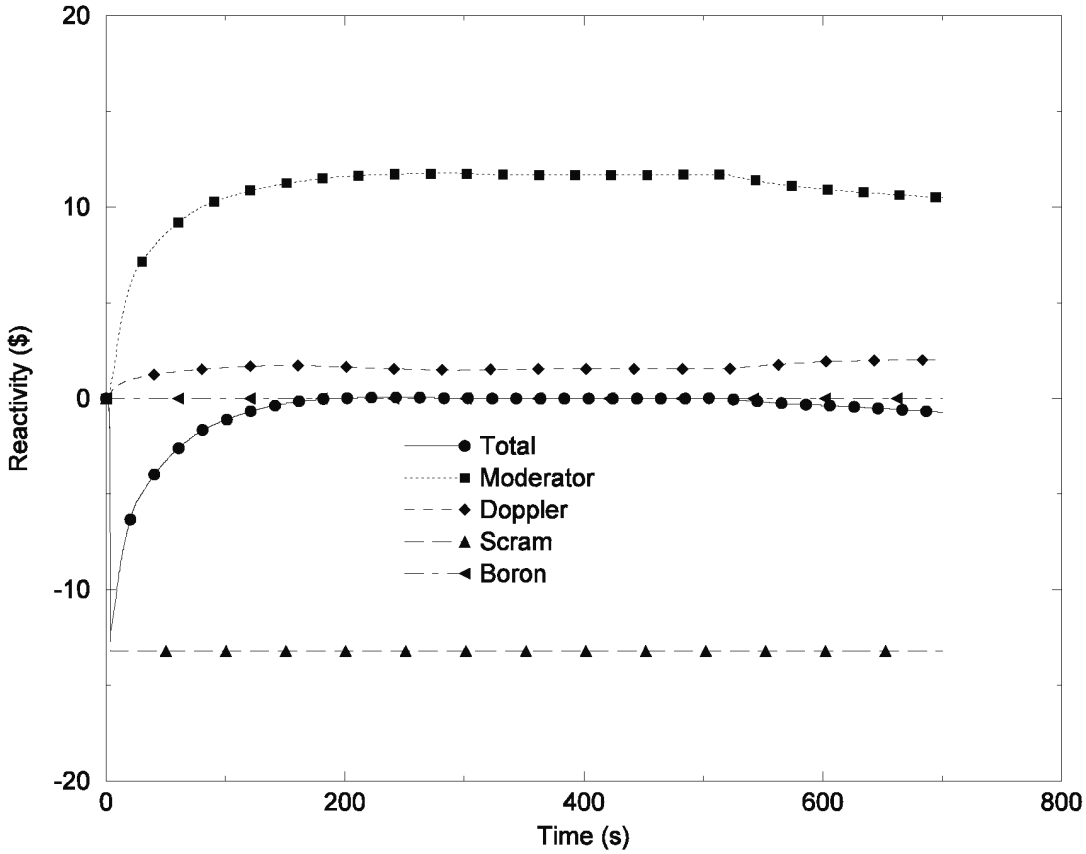
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-30
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Pressurizer Liquid Level vs. Time (AREVA)



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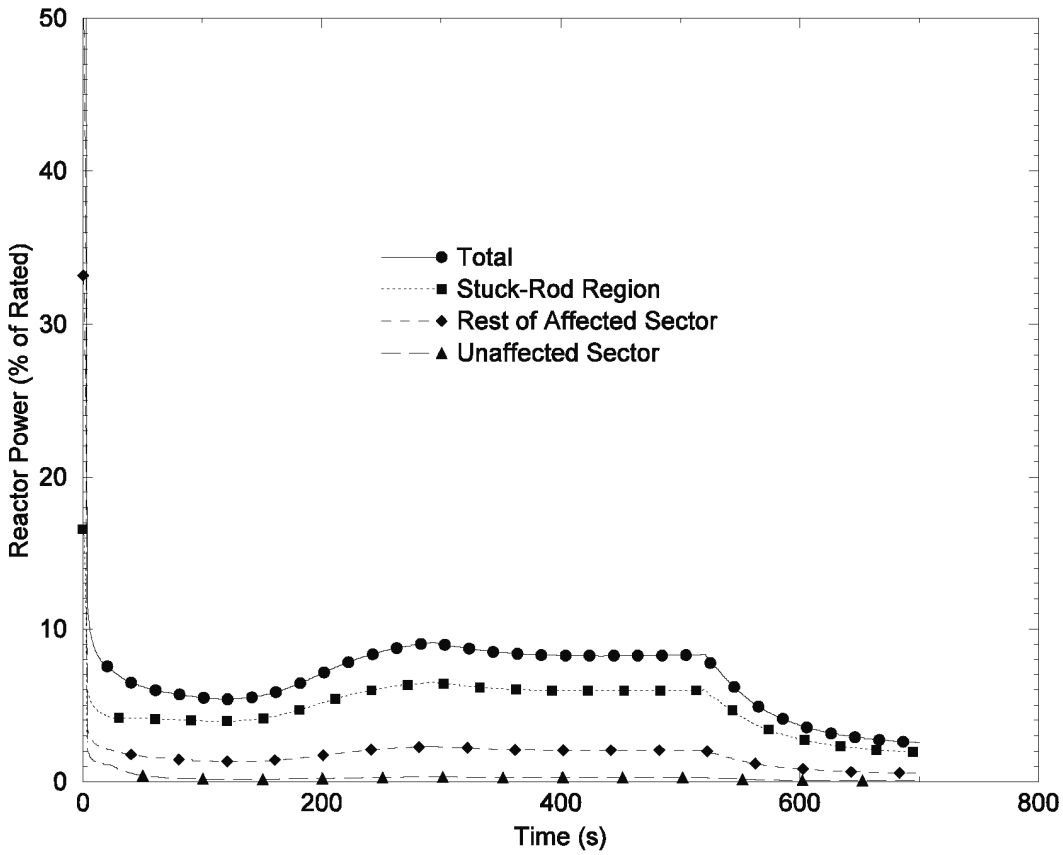
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-31
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Reactivity Feedback vs. Time (AREVA)



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FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.1.6-32
Post-Trip Main Steamline Break
(HFP Offsite Power Available):
Reactor Power vs. Time (AREVA)

15.2 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

A number of transients and accidents have been postulated which could result in a reduction of the capacity of the secondary system to remove heat generated in the reactor coolant system (RCS). These events are discussed in this section. Detailed analyses are presented for several such events that have been identified as more limiting than the others.

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

a. Loss of external electrical load (Section 15.2.1)

b. Turbine trip (Section 15.2.2)

c. Loss of condenser vacuum (Section 15.2.3)

d. Inadvertent closure of main steam isolation valves (BWR) (Section 15.2..4)

e. Steam pressure regulator failure (Section 15.2.5)

f. Loss of non-emergency ac power to the station auxiliaries (Section 15.2.6)

g. Loss of normal feedwater flow (Section 15.2.7)

h. Feedwater system pipe break (Section 15.2.8)

i. Transients resulting from the malfunction of one steam generator (Section 15.2.9)

The above items are considered to be ANS Condition II events, with the exception of a feedwater system pipe break, which is considered to be an ANS Condition IV event. Section 15.0.6 contains a discussion of ANS classification of plant conditions and applicable acceptance criteria.

15.2.1 LOSS OF EXTERNAL ELECTRICAL LOAD

A Loss of External Load is caused by abnormal events in the electrical distribution network which produces a reduction of steam flow from the steam generators to the turbine due to the closure of the turbine stop valves. The core and system performance following a Loss of External Load would be no more adverse than those following a Loss of Condenser Vacuum, which is described in Section 15.2.3. This remains applicable for the transition to AREVA fuel. EC287528
The radiological consequences due to steam releases from the secondary system would be less severe than the consequences of the Feedwater Line Break (see Section 15.2.8). Therefore, a detailed analysis of the Loss of External Load event is not necessary.

15.2.2 TURBINE TRIP

A Turbine Trip is caused by an electrical or mechanical malfunction of the turbine, which produces a reduction of steam flow from the steam generators to the turbine due to the closure of the turbine stop valves. The core and system performance following a Turbine Trip would be no more adverse than those following a Loss of Condenser Vacuum, which is described in Section 15.2.3. This remains applicable for the transition to AREVA fuel. The radiological EC287528
consequences due to steam releases from the secondary system would be less severe than the

consequences of the Feedwater Line Break (see Section 15.2.8). Therefore, a detailed analysis of the Turbine Trip event is not necessary.

15.2.3 LOSS OF CONDENSER VACUUM

15.2.3.1 Accident Description

The loss of condenser vacuum event is defined as a complete loss of steam load or a turbine trip from full power without a direct reactor trip. This anticipated transient is analyzed as a turbine trip from full power with a simultaneous loss of feedwater to both steam generators due to low suction pressure on the feedwater pumps. The atmospheric dump valves and the steam dump and bypass system valves are assumed to be unavailable which minimizes the amount of cooling and maximizes the RCS and Secondary peak pressures during the event.

In the event of a large loss of load in which the steam dump valves fail to open, the main steam safety valves (MSSVs) may lift and the reactor may be tripped by either of the following signals: high pressurizer pressure, or thermal margin / low pressure (TM/LP). No credit is taken for the Loss of Load trip as it is a control grade trip only. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves (PSVs) and main steam safety valves (MSSVs) are sized to protect the reactor coolant system (RCS) and steam generators (SGs) against overpressure for all load losses without assuming the operation of the steam dump system. The RCS and main steam system (MSS) steam relieving capacities were designed to ensure safety of the unit without requiring pressurizer pressure control, steam bypass control systems, or a reactor trip on turbine trip.

15.2.3.2 Method of Analysis

The input parameters for the Loss of Condenser Vacuum event are consistent with those presented in Table 15.0-27.

An initial core power of 3034.2 MWt, based on a rated power of 3020 MWt and nominal pump heat is assumed for the DNB case. A core power of 3044.2 MWt, based on a rated power of 3020 MWt, nominal pump heat, and 0.3% uncertainty is assumed for the overpressure cases.

The maximum core average temperature is assumed for the DNB and MSS cases since this maximizes the expansion of the primary system fluid. A low Tavg is assumed for the RCS overpressurization case.

A maximum steam generator tube plugging (SGTP) level of 10% per steam generator is assumed for the RCS case and the DNB case. A 0% SGTP level is assumed for the MSS case.

The loss of condenser vacuum event is analyzed using the RETRAN computer code (References 15.2-1 and 15.2-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power levels.

The loss of condenser vacuum is analyzed: (1) to confirm that the PSVs and MSSVs are adequately sized to prevent overpressurization of the primary RCS and MSS, respectively; and (2) to ensure that the increase in RCS temperature does not result in a departure from nucleate boiling (DNB) in the core.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power with no credit taken for a direct reactor trip on turbine trip. This assumption will delay reactor trip until conditions in the RCS cause a trip on some other signal. Thus, the analysis assumes a worst case transient and demonstrates the adequacy of the pressure relieving devices and plant- specific RPS setpoints assumed in the analysis for this event.

Of the three cases analyzed, one is performed to address DNB concerns, one ensures that the peak primary RCS pressure remains below 110% of the design limit (2750 psia) and the final case confirms that the peak MSS pressure remains below 110% of the SG shell design pressure (1100 psia). The major assumptions for these cases are summarized as follows:

1. For the case analyzed to demonstrate that the core thermal limits are adequately protected, minimum reactivity feedback conditions with automatic pressurizer pressure control are modeled. For this case, initial core power, reactor coolant temperature, and reactor coolant pressure are assumed to be at the nominal values consistent with steady-state full power operation. Uncertainties in initial conditions are not included in determining the DNBR limit value.

2. For the case analyzed to demonstrate the adequacy of the primary pressure relieving devices minimum reactivity feedback conditions without automatic pressurizer pressure control are modeled. Initial reactor coolant temperature is set to the lowest allowable value minus uncertainty. Initial pressurizer pressure is assumed at the minimum value for this case, since it delays reactor trip on high pressurizer pressure and results in more severe primary side temperature and pressure transients.

3. The MSS overpressurization case differs from the primary RCS overpressurization case in that automatic pressurizer pressure control is assumed in order to delay reactor trip.

The loss of condenser vacuum event results in a primary system heatup and is therefore conservatively analyzed assuming minimum reactivity feedback. This includes assuming a moderator temperature coefficient (MTC) value consistent with hot-full power (HFP) conditions and a least negative Doppler power coefficient (DPC).

Three cases are analyzed:

- For the case analyzed for DNB, automatic pressurizer pressure control is assumed. Thus, full credit is taken for the effect of the pressurizer spray in reducing or limiting the primary coolant pressure. Safety valves are also available and are modeled assuming a -3% setpoint tolerance.

- For the case analyzed for primary RCS overpressure concerns, it is assumed that automatic pressurizer pressure control is not available. Therefore, no credit is taken for the effect of the pressurizer spray or PORVs in reducing or limiting the primary coolant pressure. Pressurizer Safety valves are assumed operable, but are modeled assuming a +3% setpoint tolerance.

- For the case analyzed for MSS overpressure concerns, it is assumed that automatic pressurizer pressure control is available. Credit is taken for the effect of the pressurizer spray in reducing or limiting the primary coolant pressure, thus conservatively delaying the actuation of the reactor trip signal. Delaying the reactor trip ensures that the energy

input to the secondary system, and subsequently the MSS pressure, is maximized. The PORVs are modeled with one valve aligned to the pressurizer and one valve locked out. The PORVs are actuated upon the receipt of the high pressurizer pressure trip signal and serve to protect the PSVs against spurious actuation by limiting the primary pressure increase post-trip.

Main feedwater flow to the SGs is assumed to be lost at the time of turbine trip. No credit is taken for AFW flow since a stabilized plant condition will be reached before AFW initiation is normally assumed to occur for full-power cases.

The analysis is performed for operation at EPU conditions.

AREVA SAFDLs Challenge Analysis

For the fuel transition, detailed analyses were performed with the approved non-LOCA methodology given in Reference 15.2-7, as supplemented in Section 2.7 of Reference 15.2-8. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.2-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.2-10).

Key input parameters and their values used in the analysis of this event were consistent with, or conservative relative to, the approved Reference 15.2-7 methodology, as supplemented in Section 2.7 of Reference 15.2-8. See Table 15.0-27 for key input parameter values.

- Initial Conditions – The event was assumed to initiate from full-power conditions with the maximum core inlet temperature and TS minimum RCS flow rate. This set of conditions minimizes the initial margin to DNB. EC287528

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. The most-positive moderator reactivity feedback was analyzed using the TS most-positive limit for any power level. Positive moderator reactivity feedback leads to higher power levels during the event, as a result of the primary system heatup. Doppler reactivity was biased to minimize the effects of negative feedback from increasing fuel temperatures.

- Reactor Protection System Trips and Delays – This event was analyzed without a direct reactor trip from the turbine trip. This assumption conservatively delayed reactor trip until conditions in the RCS resulted in a High Pressurizer Pressure (HPP) trip. The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil release delay time.

- Feedwater Systems – The MFW pumps were assumed to trip at the start of the event, initiating a loss of normal feedwater.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and power-operated relief valves) parameters and equipment states were

selected to reduce the primary system pressure, which provided a conservative calculation of the MDNBR during the transient.

- Main Steam Safety Valves – The opening setpoints of the MSSVs were biased high, to the TS upper tolerance limits.

- Gap Conductance – The fuel-to-cladding gap conductance was set to a conservative BOC value, to be consistent with the time-in-cycle for the reactivity coefficients. The gap conductance accounts for fuel TCD. EC287528

- Steam Generator Tube Plugging – Maximum (20%) SGTP was assumed, so as to minimize the primary-to-secondary-side heat transfer, which exacerbates the reactivity insertion due to moderator feedback.

- Single Failure – There is no single failure that will adversely affect the consequences, because the systems designed to mitigate this event (namely, the RPS) are redundant.

15.2.3.3 Results

The transient responses for a total loss of condenser vacuum from full power operation are shown in Figures 15.2.3-1 through 15.2.3-5 for the RCS overpressure case and Figures 15.2.3-6 through 15.2.3-10 for the DNB case.

The total loss of condenser vacuum event was analyzed assuming the plant to be initially operating at full power at BOC with no credit taken for the pressurizer spray or PORVs to maximize the primary RCS pressure response. Figures 15.2.3-1 through 15.2.3-5 show the transients for this case. The neutron flux remains relatively constant prior to reactor trip, while pressurizer pressure, pressurizer water volume and RCS average temperature increase due to the sudden reduction in primary to secondary heat transfer. The reactor is tripped on the high pressurizer pressure trip signal. In this case the PSVs are actuated and maintain the primary RCS pressure below 110% of the design value. Table 15.2.3-1 summarizes the sequence of events for this case.

Figures 15.2.3-6 through 15.2.3-10 show the transient responses for the event with minimum feedback reactivity coefficients and assuming full credit for the pressurizer spray to calculate the transient DNBR response. Following event initiation, the pressurizer pressure and average RCS temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure and water volume and RCS average temperature are reached shortly after the reactor is tripped by the high pressurizer pressure trip function. The DNBR initially increases slightly, then decreases until the reactor trip is tripped, and finally, following reactor trip, increases rapidly. The minimum DNBR remains well above the safety analysis limit value. Table 15.2.3-2 summarizes the sequence of events and limiting conditions for this case.

Table 15.2.3-3 summarizes the transient response for the total loss of steam load with minimum feedback reactivity coefficients assuming full credit for the pressurizer spray to maximize the MSS pressure response. Following event initiation, the pressurizer pressure and average RCS temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure and water volume and RCS average temperature are reached shortly after the reactor is tripped by the high pressurizer pressure trip function. The MSS pressure increases, resulting in the actuation of the MSSVs, and then

decreases rapidly following reactor trip. The MSSVs actuate to limit the MSS pressure below 110% of the SG shell design pressure.

AREVA SAFDLs Challenge Analysis

The sequence of events is given in Table 15.2.3-4, and the results are given in Table 15.2.3-5. State-points for the DNB calculations were chosen at and near the time of peak heat flux. The limiting MDNBR was calculated to be above the 95/95 CHF correlation limit. The peak LHR was calculated to be less than the fuel centerline melt limit.

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The transient response is shown in Figure 15.2.3-11 through Figure 15.2.3-18. Figure 15.2.3-11 shows the reactor power as a function of time, and Figure 15.2.3-12 shows the core power based on rod surface heat flux. Figure 15.2.3-13 through Figure 15.2.3-18 show the pressurizer pressure, pressurizer liquid level, pressurizer PORVs flow rate, RCS loop temperatures, steam generator pressures, and reactivity feedback, respectively.

15.2.3.4 Conclusions

The results of the analyses show that the plant design is such that a loss of condenser vacuum without a direct or immediate reactor trip presents no hazard to the integrity of the primary RCS or MSS. Pressure relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits, i.e., 2750 psia for the primary RCS and 1100 psia for the MSS. The integrity of the core is maintained by operation of the RPS, i.e., the minimum DNBR is maintained above the safety analysis limit value. Thus, the analyses demonstrate that no core safety limit will be violated as a result of implementing the EPU, or transitioning to the use of AREVA fuel.

EC287528

15.2.4 INADVERTENT CLOSURE OF MAIN STEAM ISOLATION VALVES (BWR)

This section is not applicable to St. Lucie Unit 2. This is not changed by the transition to AREVA fuel.

EC287528

15.2.5 STEAM PRESSURE REGULATOR FAILURE

This event is not in the St. Lucie Unit 2 design basis. This is not changed by the transition to AREVA fuel.

EC287528

15.2.6 LOSS OF NON-EMERGENCY AC POWER TO THE STATION AUXILIARIES

This event is discussed with the loss of normal feedwater event in Section 15.2.7. This is not changed by the transition to AREVA fuel.

EC287528

15.2.7 LOSS OF NORMAL FEEDWATER FLOW

15.2.7.1 Accident Description

The loss of normal feedwater flow (LONF) event is defined as a complete loss of main feedwater flow while the reactor is operating at the maximum power level. A loss of main feedwater flow may occur due to the following causes:

- Breaks in the main feedwater system piping upstream of the main feedwater check valves.
- Failure or trip of the main feedwater pumps, including loss of power (for motor-driven feedwater pumps) or loss of motive steam (for turbine-driven feedwater pump).
- Spurious closure of main feedwater isolation valves or the main feedwater regulating valves.

The immediate consequence of a loss of main feedwater flow is a reduction in the steam generator water level, which if left unmitigated, will ultimately result in a reactor trip and auxiliary feedwater (AFW) actuation on a low steam generator water level signal. Following reactor trip, the rate of heat generation in the RCS (decay heat plus reactor coolant pump heat input) may exceed the heat removal capability of the secondary system. In this case, there will be an increase in the steam generator pressure and an increase in RCS pressure, RCS temperature, and pressurizer water level. This trend continues until the RCS heat generation rate falls below the secondary-side heat removal capability.

At that time, the primary pressure and temperature begin to decrease, thereby terminating the transient in terms of potential challenges to the applicable safety criteria. It is assumed that if such a transient were to occur at the plant, emergency operating procedures would be followed to bring the plant to a stable condition.

A loss-of-offsite-power (LOOP) event is identical to the LONF event except that a loss of power to the RCPs occurs simultaneously with the loss of feedwater flow. Therefore, the post-trip heat removal relies upon natural circulation in the RCS loops.

15.2.7.2 Method of Analysis

The short term consequences of these events are bounded by other analyzed events as follows:

- With respect to core consequences, the LONF and LOOP events are not as limiting as the complete loss of flow event, which is analyzed to demonstrate that the DNB design basis is satisfied.

  The LONF event results in a slight increase in the RCS temperature prior to reactor trip and there is no appreciable increase in the core power and RCS flow is maintained. The DNBR effect of the reduction in RCS flow for the complete loss of flow event is more significant than the effect of the increase in the RCS temperatures observed for the LONF event, prior to reactor trip.

  In the case of the LOOP event, the RCPs would coast down immediately in addition to the loss of feedwater flow. This transient would essentially be identical to the complete loss of flow event with the only exception that the reduction in feedwater flow will eventually reduce the cooling of the primary system which would result in an increased RCS pressure thereby increasing the DNBR in comparison to the complete loss of flow analysis. The increase in SG primary side exit temperature would not have sufficient time to transport to the core inlet to adversely affect the DNBR calculation. Therefore, the LOOP event has similar RCS conditions to the complete loss of flow event with the

exception of a higher RCS pressure caused by loss of feedwater flow, as such, the minimum DNBR conditions are bounded by the Complete Loss of Flow event.

In addition, since there is no appreciable power increase in either the LONF or LOOP event and since the fuel centerline melting is primarily driven by the core power, the fuel centerline melt limits will not be challenged. Therefore, the DNB and fuel centerline melting criteria continue to be satisfied for the LONF and LOOP events.

- With respect to overpressurization, the loss of condenser vacuum/turbine trip event (LOCV) will be more limiting than either the LONF or LOOP events. The LOCV presents a much more significant reduction in the heat removal capability of the steam generators than theLONF or LOOP events because the LOCV event combines the loss of normal feedwater with a turbine trip. This causes the LOCV to have a faster pressurization of the RCS compared to the LONF and LOOP events. The net result for the LOCV event is a total loss of secondary heat sink, which results in the greatest challenge to primary and secondary overpressurization. Therefore, the LOCV remains the most limiting event with respect to primary and secondary overpressurization.

- With respect to long-term cooling, the ability of the auxiliary feedwater system to remove decay heat following reactor trip is demonstrated by the analyses presented in Chapter 10.

As part of the EPU project, two additional LONF scenarios were analyzed. First, the LONF event is analyzed to ensure subcooling margin is retained and the second LONF case was analyzed to ensure the peak primary pressure remained below 110% of the design limit. The first case is analyzed with the following conservations:

- The pressurizer heaters and spray as well as the charging and letdown systems are assumed to be unavailable.

- The initial pressurizer pressure is set to nominal minus uncertainties to delay the reactor trip and minimize the subcooling available during the transient.

- RCS temperature and RCP power were set to the maximum values including applicable uncertainties to minimize the subcooling available during the transient.

- The MSSV setpoints include the maximum positive tolerance to minimize the subcooling available during the transient.

- The pressurizer liquid level was set to nominal plus uncertainty to maximize the RCS water inventory and minimize the subcooling available during the transient.

This LONF case is analyzed to ensure subcooling margin is retained and the event is concluded at the time of a decreasing hot leg temperature trend.

A second case is analyzed for RCS overpressurization. The concern is that following reactor trip, there is a potential for an increase in RCS pressure which may challenge the acceptance criterion of remaining below 110% of the design limit. As discussed herein, with respect to short term primary and secondary pressurization, the LONF and LOOP events bounded by the LOCV event as the LOCV event combines a loss of feedwater with a turbine trip.

The LONF RCS overpressurization case discussed herein is modeled with the following conservatisms:

- The pressurizer heaters are available. This increases the rate at which the pressure excusion occurs.
- The PORV is assumed unavailable. Only the PSVs are available for primary pressure relief.
- The high pressurizer pressure trip setpoint is increased to include uncertainties to maximize the primary pressure increase prior to the RSVs providing relief.

The RCS overpressurization case is analysed until the second pressure excursion is reached. The acceptance criterion for this event is to remain below 110% of the design limit (2750 psia).

Both cases are analyzed with the detailed digital computer code RETRAN (References 15.2-1 and 15.2-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

15.2.7.3 Results

Subcooling:

The LONF event is analyzed until the hot leg temperature indicates a decreasing trend or until operation action (1800 seconds). The transient response for the event are shown in Figures 15.2.7-1 through 15.2.7-7. Figure 15.2.7-2 presents RCS pressure versus time. Following the loss of feedwater, RCS pressure increases sharply until a reactor trip on high pressurizer pressure occurs. Pressure initially subsides post-trip but increases due to the reduced heat removal capability of the SGs. The pressure eventually becomes steady at the PORV opening setpoint. Similarly, as shown in Figure 15.2.7-4, RCS loop temperatures increases pre-trip, subside with the reduction in core power, and increase again late in the event due to the reduced heat removal capability. Figures 15.2.7-5 and 15.2.7-7 indicate that sufficient hot leg subcooling margin and SG inventory remain throughout the duration of the event. Table 15.2.7-1 summarizes the sequence of events for this case.

RCS Overpressurization:

The overpressurization case is based on the subcooling case with only a few changes, and therefore, the transient response is similar to that presented in Figures 15.2.7-1 through 15.2.7-7, with the exception of RCS pressure. Figure 15.2.7-8 presents RCS pressure versus time. As shown in the figure, with the addition of the pressurizer heaters and the unavailability of the PORV, the peak RCS pressure exceeds that presented in Figure 15.2.7-2 for the subcooling case. In both cases, however, the peak RCS pressure continues to be bounded by the LOCV event. Table 15.2.7-2 presents the sequence of events for this case.

15.2.7.4 Conclusion

The results of both analyses demonstrate that the plant design is such that the AFW system adequately provides heat removal following a LONF or LOOP. The analyses presented herein demonstrate that there is no hazard to the integrity of the primary RCS. Pressure relieving

devices that have been incorporated into the plant design are adequate to limit the maximum RCS pressure to within the safety analysis limit of 2750 psia. The short term acceptance criteria of peak RCS pressure, peak MSS pressure and DNBR continue to be bounded by other events. Subcooling margin is maintained throughout the event demonstrating the adequacy of the secondary side system to provide decay heat removal capability.

The fuel design change does not affect the decay heat removal capability, nor are fuel design parameters key parameters regarding overpressure. Therefore, these conclusions remain applicable for the transition to AREVA fuel. EC287528

15.2.8 FEEDWATER SYSTEM PIPE BREAK

15.2.8.1 Accident Description

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to maintain shell-side fluid inventory in the steam generators. Depending upon the size and location of the rupture and the plant operating conditions, the event can cause either a cooldown or a heatup of the reactor coolant system. Since the Reactor Coolant System (RCS) cooldown resulting from a secondary system pipe break is covered by the steam line break event, only the RCS heatup aspects are emphasized for the case of feedwater line break.

A feedwater line break reduces the capability of the secondary system to remove heat generated by the core from the RCS. The feedwater flow to the steam generators is reduced or terminated, resulting in a decrease in the shell-side fluid inventory. Moreover, fluid from the faulted steam generator can be expelled through the broken pipe, thereby eliminating the capability of the steam generator to remove heat from the RCS. A broken feedwater line may also prevent the addition of main feedwater to the intact steam generator.

The feedwater line break is one of the events which defines the required minimum capacity of the auxiliary feedwater system for removing core residual heat following reactor trip. If sufficient heat removal capability is not provided, core residual heat following reactor trip could raise the RCS coolant temperature to the extent that the resulting fuel damage would compromise the maintenance of a coolable geometry of the core, and result in potential radioactive releases. For St. Lucie Unit 2, the analysis used to justify the auxiliary feedwater requirements for a postulated feedwater line break is presented in Chapter 10.4.9A. An additional FLB case is analyzed herein demonstrating subcooling is maintained in a limiting, conservative scenario.

A feedwater line break during full-power operation may also cause a short-term pressure increase in both the RCS and main steam system challenging the integrity of the RCS and Main Steam System (MSS) pressure boundaries.

A feedwater line break is classified as an ANS Condition III or IV event, an infrequent or limiting fault, depending on break size.

15.2.8.2 Method of Analysis

The feedwater line break analysis assumes a break in a feedwater line at the steam generator inlet nozzle. Such a break results in an uncontrolled discharge of fluid from the steam generator. A break upstream of the feedwater line check valve would affect the RCS only as a loss of normal feedwater.

This accident is analyzed: (1) to confirm that the Pressurizer Safety Valves (PSVs) and Main Steam Safety Valves (MSSVs) are adequately sized to prevent overpressurization of the primary RCS and MSS, respectively; and (2) to ensure that the DNB design basis is satisfied; and (3) to demonstrate subcooling is maintained in a limiting, conservative scenario. Chapter 10.4.9A presents the design basis analysis for demonstrating the adequacy of the auxiliary feedwater system in removing long-term decay heat.

The feedwater line break transient is analyzed by employing the detailed digital computer code RETRAN (References 15.2-1 and 15.2-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The short-term effects of the event are analyzed to demonstrate that the following acceptance criteria are met:

1. Peak RCS Pressure is maintained below 110% of the RCS design pressure (2750 psia) for small (low probability) break sizes (≤ 0.20 ft^2) with or without a failure of the fast bus transfer (FFBT). Peak RCS Pressure is maintained below 110% of the RCS design pressure (2750 psia) for large break sizes (> 0.20 ft^2) without a FFBT.

2. Peak RCS Pressure is maintained below 3000 psia (120% of the RCS design pressure) for large break sizes (> 0.20 ft^2) with a FFBT (very low probability).

3. Peak MSS pressure is maintained below 110% of the steam generator shell design pressure (1100 psia).

An additional case is analyzed to demonstrate that subcooling is maintained throughout the transient with applicable uncertainties applies.

The following feedline break related events are analyzed:

1. RCS Over-Pressurization

2. MSS Over-Pressurization

A case is also analyzed to ensure that subcooling margin is maintained during a postulated FLB. The event is analyzed to ensure there is sufficient subcooling margin at the point the hot leg temperature begins to recover and decrease.

The major assumptions for the short term cases are summarized as follows:

In order to give conservative results in calculating the maximum RCS and MSS pressures during the transient, the following assumptions are made:

1. The initial reactor power is assumed to be at its maximum value plus uncertainty, the initial RCS flow rate is assumed at a value consistent with the thermal design flow rate and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications minus the pressure measurement uncertainty.

2. For maximum RCS pressure, the RCS temperature is assumed to be at Low-T_{avg} conditions minus uncertainty. For maximum MSS pressure, the RCS temperature is assumed to be at High-T_{avg} conditions plus uncertainty.

3. For maximum RCS pressure, the initial Steam Generator tube plugging level is assumed to be at the maximum plugging level. For maximum MSS pressure, the initial Steam Generator tube plugging level is assumed to be at the minimum plugging level.

4. The initial Steam Generator water level is assumed to be at the minimum water level, consistent with the low-level alarm setpoint minus the SG level measurement uncertainty.

5. The High Pressurizer Pressure and Low Steam Pressure reactor trip setpoints for adverse conditions are assumed. The Low-Low Steam Generator Level reactor trip is not credited.

6. The feedline break is assumed to occur at the physical inlet nozzle location on the steam generator.

7. An fL/D of 0 (zero) is assumed for the break and the blowdown quality is calculated by the RETRAN code.

8. A break size spectrum is analyzed to determine the limiting size with respect to RCS and MSS overpressurization.

9. Minimum reactivity feedback is assumed to maximize the energy input to the primary coolant.

10. For the RCS over-pressurization case, no credit is taken for the effect of the pressurizer spray in reducing or limiting primary coolant pressure and the PORV is not considered, since it would actuate after reactor trip on high pressurizer pressure. For the MSS overpressurization case, credit is taken for the effect of the pressurizer spray in reducing or limiting primary coolant pressure and the PORV is considered as these delay the time to reactor trip on high pressurizer pressure. Pressurizer safety valves are available, but are modeled assuming a +3% setpoint tolerance for all cases.

11. For the peak RCS pressure case, the failure of the fast bus transfer at the time of reactor trip breaker opening is modeled, which results in two of the four reactor coolant pumps coasting down. The remaining two reactor coolant pumps are assumed to coast down 3 seconds following the time of reactor trip breaker opening due to the loss of offsite power.

The initial conditions are summarized in Table 15.0-27.

The Feedline Break methodology also considers the possibility of a Loss of Offsite Power (LOOP) event. For the peak RCS pressure analysis, the LOOP is assumed to occur 3 seconds following the reactor trip breaker opening which results in the two remaining reactor coolant pumps coasting down. However, assuming a loss of offsite power does not adversely impact the RCS overpressurization results since the peak RCS pressure occurs soon after reactor trip

on High Pressurizer Pressure. For the MSS pressure case, losing RCPs retards heat transfer to the intact SG, leading to a lower peak secondary side pressure and therefore is not modeled.

With respect to the DNB design basis, the feedwater line break event with FFBT is bounded by the pre-trip steam line break event with FFBT (Section 15.1.5).

The subcooling adequacy FLB case was performed with the following assumptions/conservatisms:

1. Only the case with offsite power available was analyzed. The offsite power available case is the limiting case as the addition of the RCP pump heat results in a decrease in subcooling margin.

2. The pressurizer heaters and spray, as well as the charging and letdown systems are assumed to be unavailable.

3. The initial pressurizer pressure is set to nominal minus uncertainties to delay the reactor trip and decrease the subcooling margin.

4. RCS temperature and RCP power were set to the maximum values including applicable uncertainties to minimize the subcooling margin.

5. The MSSV setpoints include the maximum positive tolerance to minimize the subcooling margin.

6. The pressurizer liquid level was set to nominal plus uncertainty to maximize the RCS water inventory and increase the primary system heat load.

7. The intact steam generator initial liquid level was set to the nominal value minus uncertainty to minimize the initial available inventory. The faulted steam generator initial liquid level was set to the nominal value plus uncertainty to delay the reactor trip on low SG level.

8. The AFAS low SG level trip setpoint was set to the nominal value minus the harsh environment uncertainty to delay AFW initiation.

9. The low SG level trip setpoint was set to the nominal value minus uncertainty to delay reactor trip.

10. The pressurizer PORV was assumed available to minimize RCS pressure which is conservative for subcooling margin degradation.

11. The AFW flow rate is modeled based on SG pressure.

12. It is assumed the operator will manually trip the RCPs 15 minutes into the event and actuate an ADV on the intact generator 25 minutes into the event.

13. A SG Blowdown of 120 gpm per generator is modeled.

15.2.8.3 Results

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Results for Short Term Effects:

The Feedwater Line Break event was analyzed assuming the plant to be initially operating at full power at BOC (minimum feedback reactivity coefficients) to determine the primary RCS pressure response. Further, the low-low SG level reactor trip function was not credited. A break spectrum from 0.10 ft^2 to 0.375 ft^2 was analyzed to assure that the maximum RCS pressure case(s) would be captured.

The applicable RCS pressure acceptance criterion for “low probability” feedline breaks, which are defined as any break with offsite power available, break sizes ≤ 0.20 ft^2 with FFBT, or break sizes > 0.20 ft^2 without FFBT, is that the pressure must remain less than 110% of the design pressure. Table 15.2.8-1 provides the sequence of events and limiting conditions for both cases.

The applicable RCS pressure acceptance criterion for “very low probability” feedline breaks, which are defined as any break with the loss of offsite power or breaks greater than 0.20 ft^2 with FFBT, is that the pressure must remain less than 120% of the design pressure. Both scenarios were analyzed (breaks > 0.20 ft^2 with FFBT and breaks with a loss of offsite power). Figures 15.2.8-1c through 15.2.8-6c show the transient results for the limiting break case of 0.21ft^2 with failure of the fast bus transfer. In this case, the PSVs are actuated and maintain the primary RCS pressure below 120% of the design value. Table 15.2.8-1b provides the sequence of events and limiting conditions for the 0.21 ft^2 case with failure of the fast bus transfer.

To determine the Main Steam System pressure response, the Feedwater Line Break event is analyzed at BOC (minimum feedback reactivity coefficients) assuming 0% SGTP. This analysis does not credit the low SG level reactor trip function. A break spectrum from 0.05 ft^2 to 0.375 ft^2 was analyzed to assure that the maximum MSS pressure case is captured. The limiting break size is 0.05 ft^2. The main steam system pressure increases, resulting in the opening of the first five Main Steam Safety Valves, then decreases rapidly following reactor trip. The MSSVs actuate to limit the Main Steam System pressure below 110% of the SG shell design pressure. Table 15.2.8-2a provides the sequence of events and limiting conditions for the 0.05 ft^2 case, and Figures 15.2.8-7 through 15.2.8-12 show the transient results. (Note: Due to the small break size, the MSS pressure and break flow response for the 0.05 ft^2 case are much different from those presented for the limiting RCS Overpressurization case.)

Subcooling Results:

Figures 15.2.8-13 through 15.2.8-22 present the transient responses of key parameters. The sequence of events for these cases is presented in Table 15.2.8-2b. The hot leg temperatures begin to decrease at 1640.0 seconds. At that time, Figure 15.2.8-17 shows that subcooling margin still exists. The continued decrease in subcooling margin after that time is due to a primary pressure decrease from the cooling of the reactor coolant system. However, the hot leg temperature has begun to decease with subcooling margin intact, demonstrating the secondary side systems are adequate to remove decay heat during a FLB accident.

Figure 15.2.8-14 shows that the pressurizer goes water solid at approximately 1065.0 seconds. At this point, liquid would discharge through the PORVs until the pressure is reduced to close the PORV. Figure 15.2.8-22 shows the integrated release of fluid through the PORV, this includes both liquid and steam while the PORV is open.

15.2.8.4 Feedwater Line Break Radiological Analysis

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15.2.8.4.1 Background

This event involves a rupture of a main feedwater system pipe during plant operation. The rupture rapidly reduces the steam generator secondary inventory causing a partial loss of secondary heat sink, thereby allowing the heat-up of the Reactor Coolant System (RCS). The RCS is protected from overpressurization by the high pressurizer pressure trip and the pressurizer safety valves. A loss of offsite power occurs at the time of the trip. Plant cooldown is achieved via the remaining unaffected steam generator.

UNIT 2

Two sources of radioactivity contribute to the evaluated doses: initial activity in the RCS at the Technical Specification limits of 1.0 μCi/gm dose equivalent I-131 and 518.9. μCi/gm DE Xe-133 and initial activity in both steam generators at the Technical Specification (TS) limit of 0.1 μCi/gm (dose equivalent I-131). The analysis considers the initial activity in the steam generators and the activity added from the primary-to-secondary leakage as specified in Technical Specification 6.8.4.l. The initial activity from the RCS and secondary sides are transported to off-site and control room receptors via the broken feedwater line and via steam release associated with cooldown. Consistent with the current licensing basis, the analysis demonstrates that Technical Specification limits on primary and secondary system activities limit dose from this event to a small fraction of the regulatory exposure guidelines (in this case, 2.5 rem TEDE or 10% of the 10 CFR 50.67 EAB and LPZ limit of 25 rem TEDE).

15.2.8.4.2 Compliance with RG 1.183 Regulatory Positions

Since Regulatory Guide 1.183 does not provide any direct guidance regarding analysis of a Feedwater Line Break, Standard Review Plan (SRP) Section 15.8.2 is used as the primary source of guidance for this analysis. In addition, the RG 1.183 guidance provided for other events is applied to this event as applicable and appropriate. Therefore, the FWLB event dose consequence analysis is performed following the guidance provided in RG 1.183, as discussed below. The St. Lucie Unit 2 AST dose analysis methodology is presented in NAI-1101-044, “AST Licensing Technical Report for St. Lucie Unit 2”.

1. Regulatory Position 3 of Appendix E - The activity released from the fuel is assumed to be released instantaneously and homogeneously through the primary coolant.

2. Regulatory Position 4 of Appendix E - Iodine releases from the faulted SG and the unaffected SG to the environment are assumed to be 97% elemental and 3% organic.

3. Regulatory Position 5.1 of Appendix E - The primary-to-secondary leak rate is apportioned between the SGs as specified by TS 6.8.4.l (0.5 gpm total, 0.25 gpm to any one SG). Thus, the tube leakage is apportioned equally between the two SGs.

4. Regulatory Position 5.2 of Appendix E - The density used in converting volumetric leak rates to mass leak rates is based upon RCS conditions, consistent with the plant design basis.

5. Regulatory Position 5.3 of Appendix E - The primary-to-secondary leakage is assumed to continue until after shutdown cooling has been placed in service and the temperature of the RCS is less than 212°F.

6. Regulatory Position 5.4 of Appendix E - All noble gas radionuclides released from the primary system are assumed to be released to the environment without reduction or mitigation.

7. Regulatory Position 5.5.1 of Appendix E - In the faulted SG, all of the primary-to-secondary leakage is assumed to flash to vapor and be released to the environment with no mitigation. For the unaffected steam generator used for plant cooldown, a portion of the leakage is assumed to flash to vapor based on the thermodynamic conditions in the reactor and secondary immediately following plant trip when tube uncovery is postulated. The primary-to- secondary leakage is assumed to mix with the secondary water without flashing during periods of total tube submergence.

8. Regulatory Position 5.5.2 of Appendix E - The postulated leakage that immediately flashes to vapor is assumed to rise through the bulk water of the SG, enter the steam space, and be immediately released to the environment with no mitigation; i.e., no reduction for scrubbing within the SG bulk water is credited.

9. Regulatory Position 5.5.3 of Appendix E - All of the SG tube leakage flow that does not flash is assumed to mix with the bulk water.

10. Regulatory Position 5.5.4 of Appendix E - The radioactivity within the bulk water is assumed to become vapor at a rate that is a function of the steaming rate and the partition coefficient. A partition coefficient of 100 is assumed for the iodine. The retention of particulate radionuclides in the SGs is limited by the moisture carryover from the SG. The same partition coefficient of 100, as used for iodine, is assumed for other particulate radionuclides. This assumption is consistent with the SG carryover rate of less than 1%.

11. Regulatory Position 5.6 of Appendix E - Steam generator tube bundle uncovery in the unaffected SG is postulated for up to 45 minutes following a reactor trip for St. Lucie Unit 2. During this period, the fraction of primary-to-secondary leakage which flashes to vapor is assumed to rise through the bulk water of the SG into the steam space and is assumed to be immediately released to the environment with no mitigation. The flashing fraction is based on the thermodynamic conditions in the reactor and secondary coolant. The leakage which does not flash is assumed to mix with the bulk water in the steam generator. A conservative uncovery time of 60 seconds was assumed in the analysis.

15.2.8.4.3 Other Assumptions

1. The feedwater line break is assumed to be located outside of containment resulting in a blowdown of the affected generator to atmosphere from the most limiting release location (i.e., highest atmospheric dispersion factor along the feedwater line outside of containment).

2. The initial RCS activity is assumed to be at the TS 3.4.8 limit of 1.0 µCi/gm Dose EquivalentI-131 and 518.9. µCi/gm DE Xe-133. The initial SG activity is assumed to be at the TS 3.7.1.4 limit of 0.1 µCi/gm Dose Equivalent I-131.

3. The steam mass release values for the intact SG are provided in Table 15.2.8-5.

4. The RCS fluid density used to convert the primary-to-secondary leakage from a volumetric flowrate to a mass flow rate is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. The high initial cooldown rate conservatively maximizes the fluid density. The SG tube leakage mass flow rate is provided in Table 15.2.8-6.

5. For the purposes of determining the iodine concentrations, the SG mass is assumed to remain constant throughout the event. However, it is also assumed that operator action is taken to restore secondary water level above the top of the tubes within a conservative time of one hour following a reactor trip.

15.2.8.4.4 Methodology

Input assumptions used in the dose consequence analysis of the FWLB are provided in Table 15.2.8-4. The analysis assumes that the entire fluid inventory from the faulted SG is immediately released to the environment. The secondary coolant iodine concentration is assumed to be the maximum value of 0.1 µCi/gm DE I-131 permitted by TS. Additional activity due to primary-to- secondary leakage into the faulted SG is also released directly to the environment. This leakage continues until the affected steam generator is completely isolated at 12.4 hours.

Primary-to-secondary tube leakage is also postulated to occur in the unaffected SG. This activity is diluted by the contents of the steam generator and released via steaming from the ADVs, along with the initial iodine activity of unaffected SGs. All releases from the unaffected steam generator continue until the RCS is cooled to 212°F.

For this event, the Control Room ventilation system cycles through three modes of operation:

- Initially the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 395 cfm of unfiltered inleakage.

- After the start of the event, the Control Room is isolated due to a high radiation signal from the Control Room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 395 cfm of unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

- At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside to the control room as per procedures. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.

15.2.8.4.5 Radiological Consequences

The atmospheric dispersion factors (χ/Qs) used for this event for the Control Room dose are based on the postulated release locations and the operational mode of the control room ventilation system. The release-receptor point locations are chosen to minimize the distance from the release point to the Control Room air intake.

Releases from the intact SG are assumed to occur from the ADV that produces the most limiting χ/Qs. Releases from the faulted SG are assumed to occur from the most limiting feedwater line. When the Control Room Ventilation System is in normal mode, the most limiting χ/Q corresponds to the worst air intake to the control room. When the ventilation system is isolated, the limiting χ/Q corresponds to the midpoint between the two control room air intakes. The operators are assumed to reopen the most favorable air intake at 1.5 hours. Development of control room atmospheric dispersion factors is discussed in Appendix 2.5D. These χ/Qs applied in the FWLB analysis are summarized in Table 15.2.8-7.

For the EAB dose analysis, the χ/Q factor for the zero to two-hour time interval is assumed for all time periods. Using the zero to two-hour χ/Q factor provides a more conservative determination of the EAB dose, because the χ/Q factor for this time period is higher than for any other time period. The LPZ dose is determined using the χ/Q factors for the appropriate time intervals. These χ/Q factors are provided in Appendix 2.5C.

The radiological consequences of the FWLB Accident are analyzed using the RADTRAD-NAI code and the inputs/assumptions previously discussed. As shown in Table 15.2.8-3, the results of the FWLB for EAB dose, LPZ dose, and Control Room dose are all within the appropriate regulatory acceptance criteria.

15.2.8.5 Conclusion

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The results of the analyses show that the plant design is such that a feedwater line break presents no hazard to the integrity of the primary RCS or MSS by meeting all applicable Condition II acceptance criteria. Pressure relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits, i.e, 2750 psia or 3000 psia, as appropriate, for the primary RCS and 1100 psia for the MSS. The integrity of the core is maintained by operation of the RPS. With respect to the DNB design basis, the feedwater line break event is bounded by the pre-trip steam line break event (Section 15.1.5).

The radiological consequences of the feedwater line break were found to be less than the guidelines established for design basis accidents.

AREVA

The DNB aspects of this event prior to reactor trip are bounded by the AREVA fuel transition analysis for Pre-Trip Steam System Piping Failure (UFSAR 15.1.5). Fuel design parameters are not key parameters to overpressure. Therefore, these conclusions remain applicable for the transition to AREVA fuel. EC287528

15.2.8.6 Effect of the Replacement Steam Generator

This Feedwater System Pipe Break event could be terminated by either the PZR high pressure RPS trip or the SG low pressure RPS trip depending on the size and location of the break. While the initial SG pressure in the RSG will be higher than the OSG pressure utilized in the FWLB analysis, which may impact the timing of the SG low pressure RPS trip, the impact of this upon the RCS pressure is negligible as compared to the beneficial impact on the RCS pressure transient of the increased energy transfer to the secondary system and the increased liquid inventory of the RSGs. Overall, there is a beneficial impact on the RCS pressure and the core performance, i.e., a higher minimum DNB ratio.

The conclusion is that the FWLB event with the RSGs is bounded by the AOR with respect to RCS overpressure and the DNBR. The RSG details do not alter the aforementioned conclusion regarding the FWLB event with FFBT being bounded by the pre-trip steam line break with FFBT from DNBR considerations. However, the AOR does not bund the RSGs with respect to secondary side overpressure or radiological consequences.

Hence, a comparative analysis of the FWLB event was performed for secondary side overpressure, and the conclusion is that the RSG produced a higher peak secondary side pressure by 3.86 psi (Reference 15.2-6). The OSG AOR peak secondary side pressure is listed in Table 15.2.8-2 as 1090 psia. The maximum secondary side pressure with the RSGs is determined to be 1090 + 3.86 = 1094 psia, which is less than the acceptance criteria of 110% of the design pressure (1100 psia).

In the context of radiological consequences, the RSGs have a larger initial inventory than the OSGs at hot full power (HFP). The OSG analysis assumed that all of the initial activity in both steam generators and the activity added due to the Technical Specification allowed primary-to-secondary tube leak rate are released. Although the increased secondary side liquid mass in the RSG could adversely affect the dose consequences discussed in UFSAR Section 15.2.8.4, the OSG dose analysis utilized a conservatively large secondary side inventory that bounds the HFP and HZP RSG secondary side inventories. The change in integrated steam release to the atmosphere to cool the plant to the SDC tie-in conditions for the RSG was shown to be insignificant. Thus, the OSG analysis dose consequences remain bounding for the RSG.

15.2.9 TRANSIENTS RESULTING FROM THE MALFUNCTION OF ONE STEAM GENERATOR

15.2.9.1 Accident Description

The transients resulting from the malfunction of one steam generator are analyzed to confirm that the DNBR and fuel centerline melt design limits are not exceeded.

The four events which affect a single generator are identified below:

a. Loss of Load to One Steam Generator (LL/ISG)

b. Excess Load to One Steam Generator (EL/ISG)

c. Loss of Feedwater to One Steam Generator (LF/ISG)

d. Excess Feedwater to One Steam Generator (EF/ISG)

Of the four events described above, it has been determined that the Loss of Load to One Steam Generator (LL/ISG) transient is the limiting asymmetric event. Hence, only the results of this transient are reported.

The asymmetric steam generator transient event is defined as a complete loss of steam load to one steam generator from a full power condition. This transient is modeled as an inadvertent closure of the main steamline isolation valve to one steam generator. A concurrent termination of feedwater flow to the affected steam generator is assumed in the analysis to conservatively bound any potential response of the feedwater system. Feedwater isolation to the affected steam generator will result in an increase in the vessel inlet temperature asymmetry during the transient, which is conservative with respect to demonstrating that the DNB design basis is satisfied.

In the event of a large loss of load to a single steam generator, the main steam safety valves (MSSV) may lift and the reactor may be tripped by a High Steam Generator Differential Pressure (HSGDP) reactor trip. This trip function is specifically designed to provide protection against an asymmetric steam generator transient. Upon the loss of load to a single steam generator, the affected steam generator pressure increases to the opening setpoint of the main steam safety valves (MSSVs). Once relief flow is established through the MSSVs (including tolerances), the pressure begins to decrease in the affected steam generator and settles to a value corresponding to the MSSV setpoint pressure. The unaffected steam generator continues to supply steam to the turbine and attempts to replace the steam load previously supplied by the affected steam generator because the turbine demand is assumed to be maintained at 100%. The increase in steam flow from the unaffected steam generator results in an overcooling of the cold legs associated with the unaffected loop. Additionally, the steam pressure in the unaffected steam generator decreases due to the increased steam flow in that loop. The increase in the core inlet temperature from the affected loops in combination with the decrease in core inlet temperature from the unaffected loops results in a large core temperature asymmetry. The asymmetric core temperature distributions result in an increase in the radial and axial peaking in the core, resulting in a challenge to the DNB design basis.

15.2.9.2 Method of Analysis

The Asymmetric Steam Generator Transient event is analyzed by employing the detailed digital computer code RETRAN (References 15.2-1 and 15.2-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including the loop and core flow during the transient, the time of reactor trip, the nuclear power transient, the primary system and secondary pressure and temperature transients, and the DNBR transients.

The analysis of the asymmetric steam generator transient has been performed to demonstrate that the DNB design basis and the peak linear heat rate criteria are satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR.

The following assumptions were made in the analysis of the Asymmetric Steam Generator Transient. Table 15.0-27 also provides a listing of key input parameters and assumptions for the event:

1. The initial reactor power and RCS temperature are assumed to be at their nominal values, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit as described in the Revised Thermal Design Procedures (Reference 15.2-3).

2. Two cases were analyzed; one assuming 0% of the steam generator U-tubes to be plugged and one assuming 10% of the steam generator U-tubes to be plugged.

3. A bounding range of fuel to coolant heat transfer characteristics was evaluated to assure that the limiting statepoints are generated by the RETRAN code.

4. The initiating event is an inadvertent closure of a single Main Steam Isolation Valve with an assumed simultaneous termination of feedwater flow to the same steam generator.

5. The ASGT event results in a loss of steam flow and associated main feedwater flow to the affected steam generator. This causes a heatup in the associated primary RCS loop. The turbine demand is assumed to be maintained at 100% demand by the unaffected loop. This causes a cooldown to occur in the primary loop associated with the unaffected steam generator. The reactivity feedback is weighted to the unaffected loop since end-of-life reactivity feedback is assumed, which results in an increase in the core power due to the colder RCS temperature conditions.

6. The model assumes reactivity feedback coefficients which maximize the increase in nuclear power prior to reactor trip. These reactivity coefficients were weighted to the RCS loop associated with the unaffected steam generator to maximize the power increase. The affects associated with the asymmetric vessel inlet distribution caused by the transient were used to calculate conservative radial and axial peaking factors.

7. The cases are analyzed with the automatic pressurizer pressure control system assumed to be operable. Thus, full credit is taken for the effect of the pressurizer spray in limiting any primary coolant pressure increase above the initial pressure.

AREVA Analyses

The analyses were performed with the approved non-LOCA methodology given in Reference 15.2-7, as supplemented in Section 2.7 of Reference 15.2-8. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.2-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.2-10). EC287528

Key input parameters and their values used in the analyses of this event were consistent with, or conservative relative to, the approved Reference 15.2-7 methodology, as supplemented in Section 2.7 of Reference 15.2-8. See Table 15.0-27 for key input parameter values.

- Initial Conditions – Full power, maximum core inlet temperature, and TS minimum RCS flow rate—in order to ensure that initial conditions most challenging to the SAFDLs were used.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. EOC kinetics were analyzed. The MTC was assumed to be equal to the most-negative analytical limit. Doppler reactivity was biased to bound EOC.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, control rod insertion was delayed to account for CEA holding coil release delay time.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and PORVs) parameters and equipment states were selected to reduce the primary system pressure, which provided a conservative calculation of the MDNBR during the transient. EC287528

- Gap Conductance – The fuel-to-cladding gap conductance was set to a conservative value consistent with the time-in-cycle for the reactivity coefficients. It accounts for the effects of fuel TCD.

- Steam Generator Tube Plugging – Both 0% and 20% SGTP levels were analyzed for this event. Results are presented for the limiting case.

15.2.9.3 Results

The results of the analysis demonstrate that the asymmetric steam generator transient event meets the applicable DNB and the peak linear heat rate acceptance criteria. Table 15.2.9-1 summarizes the sequence of events for the 0% steam generator tube plugging case and Table 15.2.9-2 correspondingly summarizes the sequence of events of the 10% steam generator tube plugging case.

The transient response for the limiting asymmetric steam generator transient from full power operation are shown in Figures 15.2.9-1 through 15.2.9-8, assuming 10% SGTP, maximum reactivity feedback conditions with automatic pressurizer pressure control (pressurizer spray).

AREVA Analyses

The sequence of events for the limiting case (with 0% SGTP) is given in Table 15.2.9-3, and the results are given in Table 15.2.9-4. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation, and the peak LHR was calculated to be less than the FCM limit. The transient response is shown in Figure 15.2.9-9 through Figure 15.2.9-14. Figure 15.2.9-9 shows the reactor power as a function of time. Figure 15.2.9-10 shows the core power based on rod surface heat flux. Figure 15.2.9-11 shows the pressurizer pressure. Figure 15.2.9-12 shows the pressurizer liquid level. Figure 15.2.9-13 shows the RCS loop temperatures. Figure 15.2.9-14 shows the steam generator pressures. EC287528

15.2.9.4 Conclusions

The asymmetric steam generator transient event was conservatively analyzed with respect to the reactor core response. Key analysis assumptions were made to conservatively maximize the asymmetry in vessel inlet temperatures, so as to maximize the core power and peaking factors.

Two cases were performed to assess both the minimum DNBR and the peak linear heat rate for 0% steam generator tube plugging and for 10% steam generator tube plugging. The case with 10% of the steam generator tubes plugged was found to be the most limiting case. The DNB design basis is satisfied and the peak linear heat rate limit is not exceeded for both cases analyzed.

15.2.10 REFERENCES

15.2-1 WCAP-14882-P-A, Rev. 0, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April 1999.

15.2-2 EPRI NP-1850-CCM, Rev. 6, “RETRAN-02 – A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems,” December 1995.

15.2-3 Friedland, A. J. and Ray, S., “Revised Thermal Design Procedure,” WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

15.2-4 WCAP-9272-P-A “Westinghouse Reload Safety Evaluation Methodology,” July 1985.

15.2-5 B. T. Moroney to J. A. Stall, “St. Lucie Plant, Unit No.2 – Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC NO. MC1566),” dated January 31, 2005.

15.2-6 AREVA NP Licensing Report - 77-5069878, Replacement Steam Generator Report for Florida Power and Light, St. Lucie Unit 2.

15.2-7 EMF-2310(P)(A) Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

15.2-8 ANP-3347P Revision 0, St. Lucie Unit 2 Fuel Transition Chapter 15 Non LOCA Summary Report, AREVA Inc., December 2014.

15.2-9 XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, August 1983. EC287528

15.2-10 EMF-92-153(P)(A) Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 15.2.3-1 Sequence of Events Loss of Condenser Vacuum Without Pressurizer Pressure Control (for Primary RCS Overpressure)	
Event	**Time (seconds)***
Turbine trip	10.11
Main Feedwater Terminates (both loops)	10.11
Reactor Trip on High Pressurizer Pressure	17.46
Rod Motion Begins	18.20
Time of Peak RCS Pressure	18.70
Results	
Peak RCS Pressure	2669.36 psia
RCS Pressure Maximum Limit	2750 psia

* The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.

Table 15.2.3-2 Sequence of Events Loss of Condenser Vacuum With Pressurizer Pressure Control (for Minimum DNB)	
Event	**Time (seconds)***
Turbine Trip	10.10
Main Feedwater Terminates (both loops)	10.10
Reactor Trip on High Pressurizer Pressure	16.77
Rod Motion Begins	17.51
Time of Minimum DNBR	0.00**
Results	
Minimum DNBR Value	2.23
DNBR Minimum Limit (side thimble)	1.42

* The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.

** Note the DNBR improves over the duration of the transient, thus the minimum DNBR occurs at the beginning of the transient.

Table 15.2.3-3 Sequence of Events Loss of Condenser Vacuum With Pressurizer Pressure Control (for Main Steam System Overpressure)	
Event	**Time (seconds)***
Turbine Trip	10.11
Main Feedwater Terminates (both loops)	10.11
Reactor Trip on High Pressurizer Pressure	18.18
Rod Motion Begins	18.92
Time of Peak MSS Pressure	23.50
Results	
Peak MSS Pressure	1094.75 psia
MSS Pressure Maximum Limit	1100 psia

* The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.

Table 15.2.3-4 Loss of Condenser Vacuum (AREVA SAFDLs): Sequence of Events	
Event	Time (sec)
Turbine is tripped	0.00
Main feedwater pumps are tripped	0.00
Steam generator Bank 1 MSSVs open (both SGs)	4.25
HPP reactor trip setpoint is reached	6.11
Pressurizer PORVs open	6.11
Reactor is scrammed on HPP (including signal processing delay)	7.26
CEA insertion begins	8.01
Maximum (prior to scram) core inlet temperature is reached	8.01
Peak neutronic power occurs	8.01
Maximum clad surface heat flux occurs	8.18
MDNBR occurs	8.60

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Table 15.2.3-5 Loss of Condenser Vacuum (AREVA SAFDLs): Results	
Criterion	Result
MDNBR	1.553
Peak LHR	16.04 kW/ft

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Table 15.2.7-1 Sequence of Events For the Loss of Normal Feedwater Event Subcooling Case		
Time (sec)	**Event**	**Setpoint/Value**
0 – 20.0	Steady State Period	
20.0	Loss of Feedwater to both SGs	
48.1	High Pressurizer Pressure Setpoint Reached	2370 psia
48.1	Maximum RCS Pressure	2428 psia
48.1	Pressurizer PORV actuates	2370 psia
48.5	Reactor Trip Signal on High Pressurizer Pressure	2370 psia
49.3	Reactor Trip (CEA Release)	
50.5	Turbine Trip*	
52.2	PORV Close	2365 psia
52.3	MSSV Bank 1 Open (Both SGs)	1030 psia
53.7	MSSV Bank 2 Open (Both SGs)	1060.8 psia
79.3	AFW Actuation Signal by SG Low Level	14.25%
409.3	AFW Flow Reaches the Steam Generators	~275 gpm/SG
440.1	PORV Re-Open	2370 psia
1394.9	Minimum SG Inventory	16,743 lbm
1460.7	Maximum Pressurizer Liquid Level	1297 ft^3
~1500	Hot Leg Temperature Starts to Decrease	
1515.4	PORV Re-Close	2365 psia

* Turbine Trip is not credited in the transient analysis. The 2.0 second delay does not impact the results.

Table 15.2.7-2 Sequence of Events For Second RCS Overpressurization Loss of Normal Feedwater Event	
Event	**Time (seconds)**
Main Feedwater Terminates (both loops)	20.00
HPPT Setpoint Reached	51.86
Reactor Trip on High Pressurizer Pressure	52.26
Rod Motion Begins	53.00
First MSSV Opens	55.90
AFW Signal on SG1 Low Level	74.94
PSV Opens	367.99
Time of Peak RCS Pressure	389.30
AFW Initiated (330 second delay)	404.94
Results	
Peak RCS Pressure	2629.1 psia
RCS Pressure Maximum Limit	2750 psia

Table 15.2.8-1 Sequence of Events and Transient Results Feedwater Line Break With Offsite Power Available		
Without Pressurizer Pressure Control (for Primary RCS Overpressure)		
	Large Break (0.20 ft^2) (With FFBT)(1)	**Small Break (0.28 ft^2) (With FFBT)**
Event	**Time (seconds)**	**Time (seconds)**
Initiation of Event	0.01	0.01
Manual Feedwater Isolation (both loops)	0.01	0.01
Reactor Trip on High Pressurizer Pressure	31.79	32.28
Reactor Trip Breakers Open	32.19	32.68
Failure of Fast Bus Transfer Resulting in the Trip of two RCPs	32.19	32.68
Rod Motion Begins (0.99 seconds after breaker opens	33.18	33.67*
Time of Peak RCS Pressure	35.18	36.12
Results		
Peak RCS Pressure	2714.85 psia	2710.56 psia
RCS Pressure Limit (120% or 110%)	3000 psia	2750 psia

* A 0.99 second delay was conservatively used instead of the 0.74 second delay design basis value.

Note 1: Since the large break with FFBT case results in the peak RCS pressure meeting the criterion of 110% of the design pressure, a separate analysis without FFBT is not presented herein as it is bounded by the case with FFBT.

Table 15.2.8-2a Sequence of Events and Transient Results Feedwater Line Break Limiting Break Size = 0.05 ft^2)	
With Pressurizer Spray (for MSS Overpressure)	
Event	**Time (seconds)**
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Reactor Trip on High Pressure Pressure	38.74
Rod Motion Begins (0.74 seconds following Breaker opening)	39.88
Time of Peak MSS Pressure	44.00
Results	
Peak MSCS Pressure	1094.92 psia
MSS Pressure Limit	1100 psia

Table 15.2.8-2b Sequence of Events and Transient Results for the Feedwater Line Break Event Subcooling Case		
Time (sec)	**Event**	**Setpoint/Value**
20.00	Event Initiation; FLB occurs in the MFW line between the Loop 1 SG and the last check valve	1.23 ft^2
38.78	Loop 1 SG Low SG level Trip Setpoint Reached*	4% NR
40.05	Reactor Trip Breaker Open	1.27 second delay
40.79	CEA Release	0.74 second delay
42.05	Turbine Trip	2.0 second delay
43.39	PORV Opens	2370 psia
45.26	PORV Closes	2365 psia
113.05	SIAS Generated on Low Pressurizer Pressure	1638 psia
131.61	Loop 2 SG Reaches MSI Setpoint	487 psia
135.00	Minimum Pressurizer Volume	0 ft^3
138.36	MSIVs Completely Closed	--
138.41	Loop 2 SG Level Reaches AFW Actuation Setpoint	4.0% NR
167.50	Loop 1 SG Dryout	< 500 lbm
468.41	AFW Reaches Loop 2 SG	330 seconds
505.86	PORV Opens	2370 psia
920.00	Operator Action; All RCPs Manually Tripped	15 minutes
1520.00	Operator Action; Open ADV on Intact SG to Reduce Intact SG Pressure to 850 psia	25 minutes
1640.00	Hot Leg Temperature Begins to Decrease	--
1725.03	PORV Closes	2365 psia

TABLE 15.2.8-3 FWLB Dose Consequences			
Case	**EAB Dose (1) (rem TEDE)**	**LPZ Dose (2) (rem TEDE)**	**Control Room Dose (2) (rem TEDE)**
FWLB	0.015	0.019	0.63
Acceptance Criteria	2.5 (3)	2.5 (3)	5

(1) Worst 2-hour dose
(2) Integrated 30-day dose
(3) "Well within" is taken as 10% of the 25 rem TEDE limit from 10 CFR 50.67

TABLE 15.2.8-4

Feedwater Line Break (FWLB) – Inputs and Assumptions

Input/Assumption	Value
Core Power Level	3030 MW_{th} (3020 + 0.3%)
Initial RCS Equilibrium Activity	1.0 μCi/gm DE I-131 and 517.8 μCi/gm DE Xe-133 (Table 15.6.5-15)
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/gm DE I-131 (Table 15.1.6-6)
Steam Generator Tube Leakage	0.25 gpm per SG (Table 15.2.8-6)
Time to Terminate SG Tube Leakage	12.4 hours
Unaffected Secondary Side Mass Releases to Environment	Table 15.2.8-5
Intact SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	 1 hour 5 %
Steam Generator Secondary Side Partition Coefficient	Flashed tube flow – none Non-flashed tube flow – 100
Time to Reach 212 °F and Terminate Steam Release	12.4 hours
Unaffected SG Secondary Side Mass	minimum – 121,970.5 lb_m (one SG) Minimum mass used for intact SG to maximize steam release nuclide concentration.
Chemical Form of Iodine Released from SGs	Particulate – 0% Elemental – 97% Organic – 3%
Atmospheric Dispersion Factors Offsite Onsite	 Appendix 2.5C Table 15.2.8-7
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	 30 seconds 1.5 hours 395 cfm
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6
Control Room Occupancy Factor	RG 1.183 Section 4.2.6

TABLE 15.2.8.-5

FWLB Steam Release Rate

Time (hours)	Intact Steam Generator Release Rate (lbm/min)
0.0	9087.1
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0

TABLE 15.2.8-6

FWLB Steam Generator Tube Leakage

Time (hours)	Intact Steam Generator Tube Leakage (lbm/min)
0	1.58
0.50	1.67
1.00	1.75
1.50	1.83
2.00	1.86
4.00	1.90
6.00	1.94
9.00	1.98
11.00	2.00
12.40	0.00

TABLE 15.2.8-7

Control Room χ/Q (for releases from the unaffected steam generators)

Time (hours)	χ/Q (sec/m^3)
0	6.71E-03
0.00833	3.13E-03
1.5	1.89E-03
2	1.53E-03
8	6.02E-04
24	4.55E-04
96	3.89E-04
720	3.89E-04

Control Room χ/Q (for releases from the affected steam generator)

Time (hours)	χ/Q (sec/m^3)
0	7.29E-03
0.00833	3.33E-03
1.5	1.95E-03
2	1.57E-03
8	6.56E-04
24	4.75E-04
96	3.99E-04
720	3.99E-04

Table 15.2.9-1
Sequence of Events and Transient Results
Asymmetric Steam Generator Transient
0% Steam Generator Tube Plugging

Event	Time (seconds)*
Main Steam Isolation (Loop Two)	10.10
Manual Feedwater Termination (Loop Two)	10.10
Reactor Trip on High Steam Generator ΔP	14.93
Rod Motion Begins	15.67
Time of Minimum DNBR	0.00**

* The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.

** The DNBR value increases during the transient due to the large increasing RCS pressure, when compared to the small increase in power and core temperature, prior to reactor trip.

Table 15.2.9-2
Sequence of Events and Transient Results
Asymmetric Steam Generator Transient
10% Steam Generator Tube Plugging

Event	Time (seconds)*
Main Steam Isolation (Loop Two)	10.14
Manual Feedwater Termination (Loop Two)	10.14
Reactor Trip on High Steam Generator ΔP	14.50
Rod Motion Begins	15.24
Time of Minimum DNBR	0.00**

* The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.

** The DNBR value increases during the transient due to the large increasing RCS pressure, when compared to the small increase in power and core temperature, prior to reactor trip.

Table 15.2.9-3 Asymmetric Steam Generator Transient (AREVA): Sequence of Events (0% SGTP)	
Event	Time (sec)
MSIV-1 begins to close	0.00
MSIV-1 is fully closed	0.10
MSSV flow from affected SG begins (970 psia)	0.20
Peak average rod surface heat flux is reached (100.6% RTP)	3.00
ASGPT setpoint is reached (247 psid)	7.66
ASGPT signal is received (following 1.15 second delay)	8.81
Maximum kinetics power is reached (101.6% RTP)	9.50
CEAs insertion begins	9.55
MDNBR occurs	9.70
CEAs are fully inserted (2.85 second insertion time)	12.40

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Table 15.2.9-4 Asymmetric Steam Generator Transient (AREVA): Results (0% SGTP)	
Criterion	Result
MDNBR	1.713
Peak LHR	15.74 kW/ft

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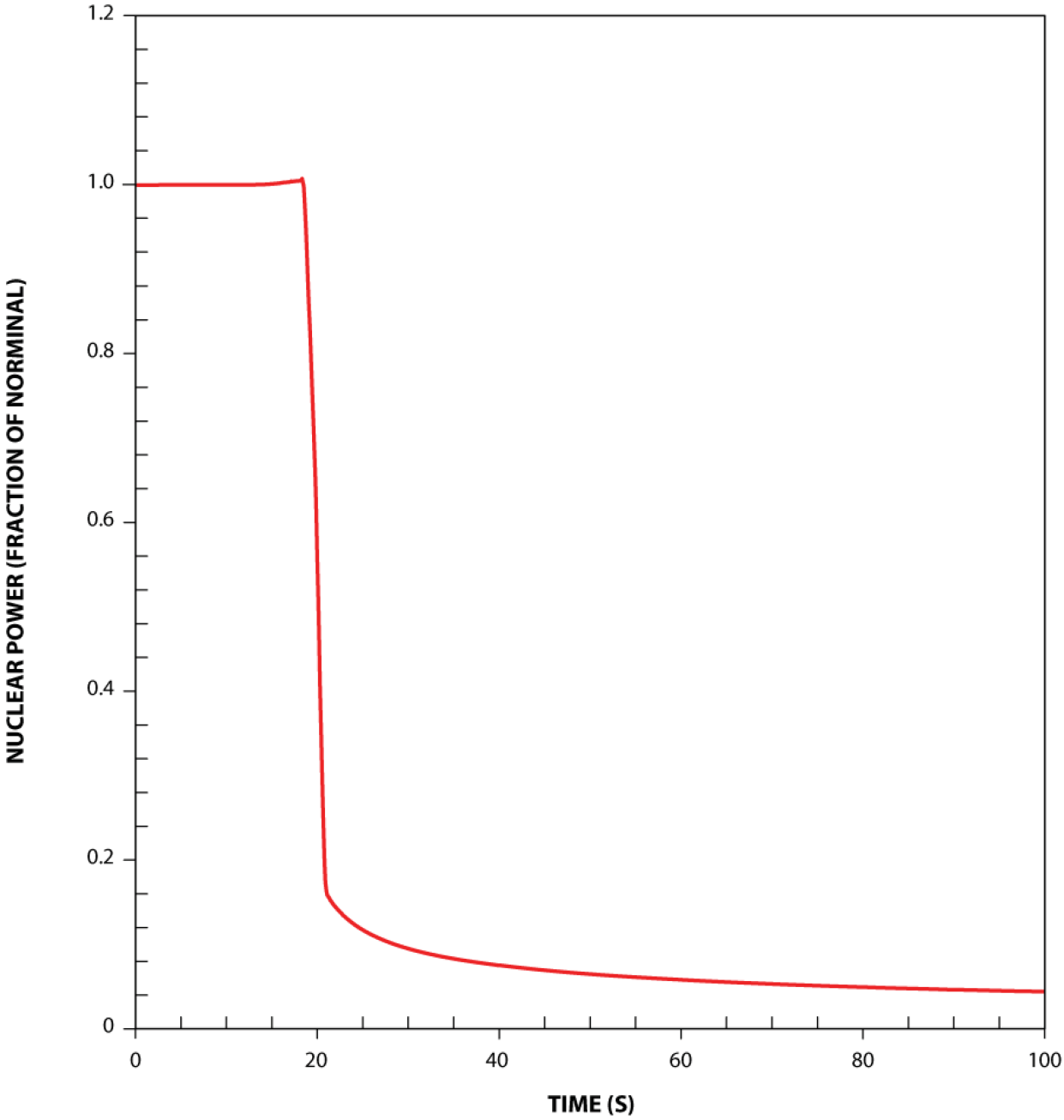

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FIGURE 15.2.3-1 Loss of Condenser Vacuum (RCS Overpressure Case) Nuclear Power vs. Time

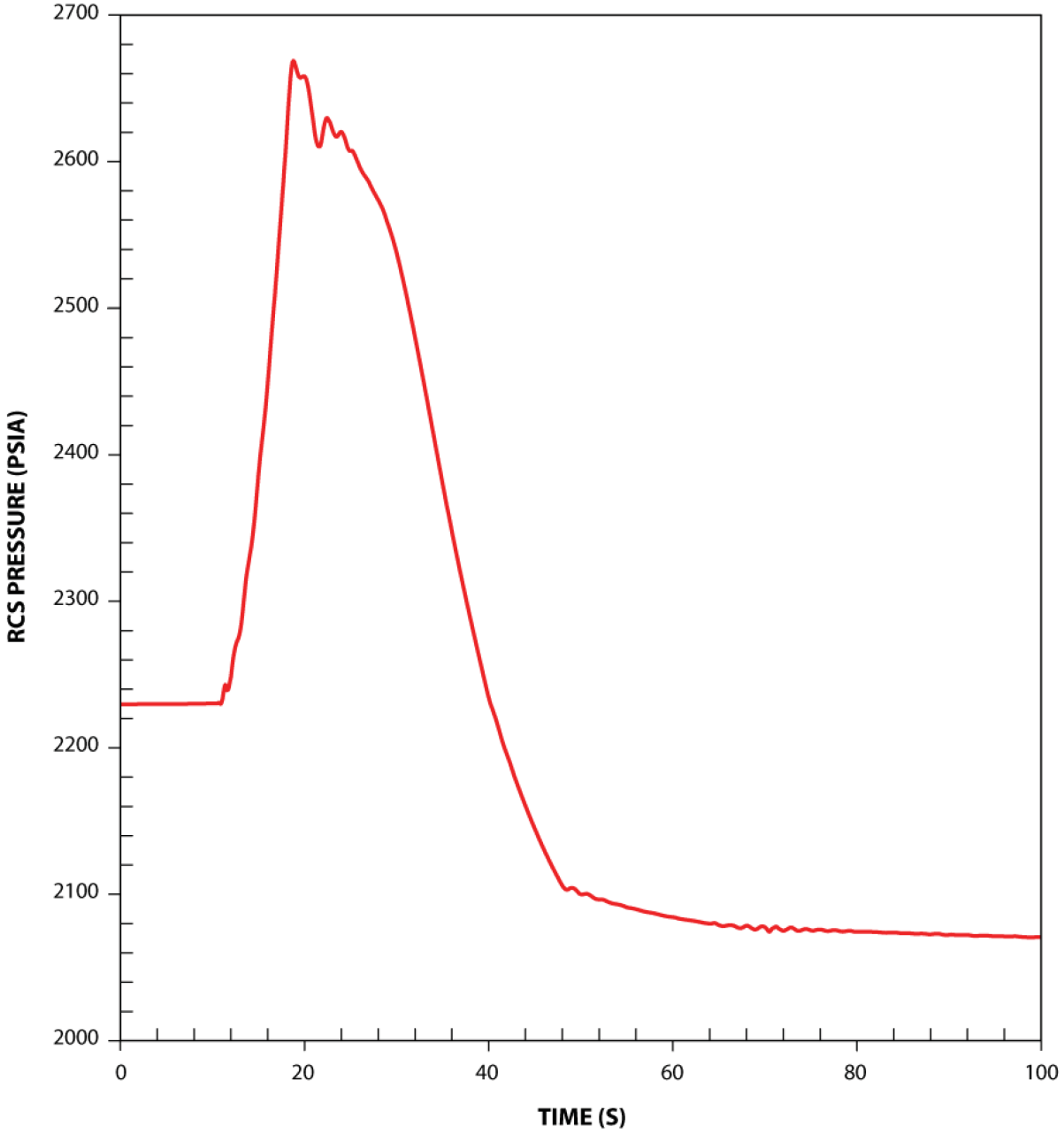

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FIGURE 15.2.3-2 Loss of Condenser Vacuum (RCS Overpressure Case) RCS Pressure (Vessel Lower Plenum) vs. Time

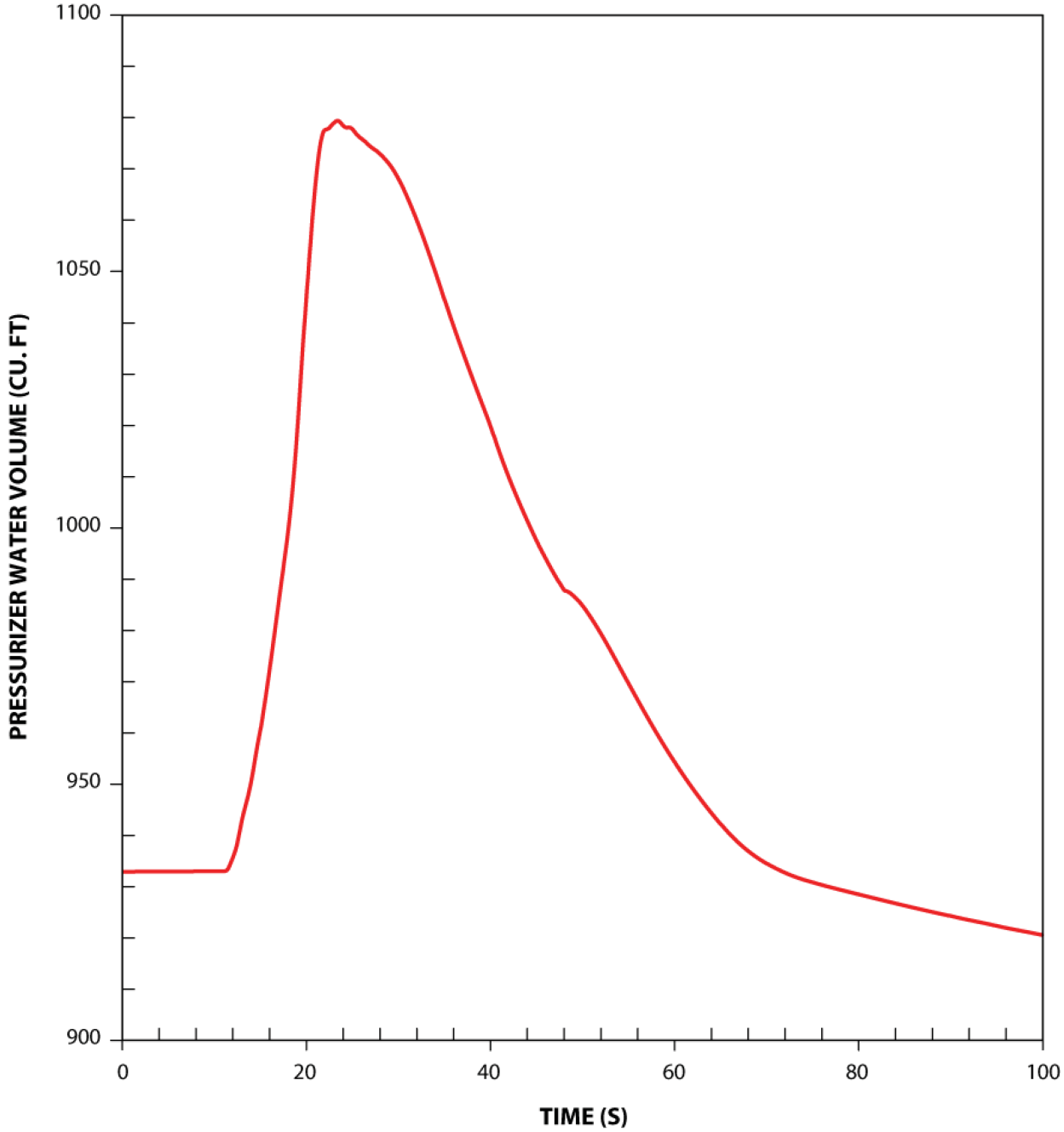

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FIGURE 15.2.3-3 Loss of Condenser Vacuum (RCS Overpressure Case) Pressurizer Water Volume vs. Time

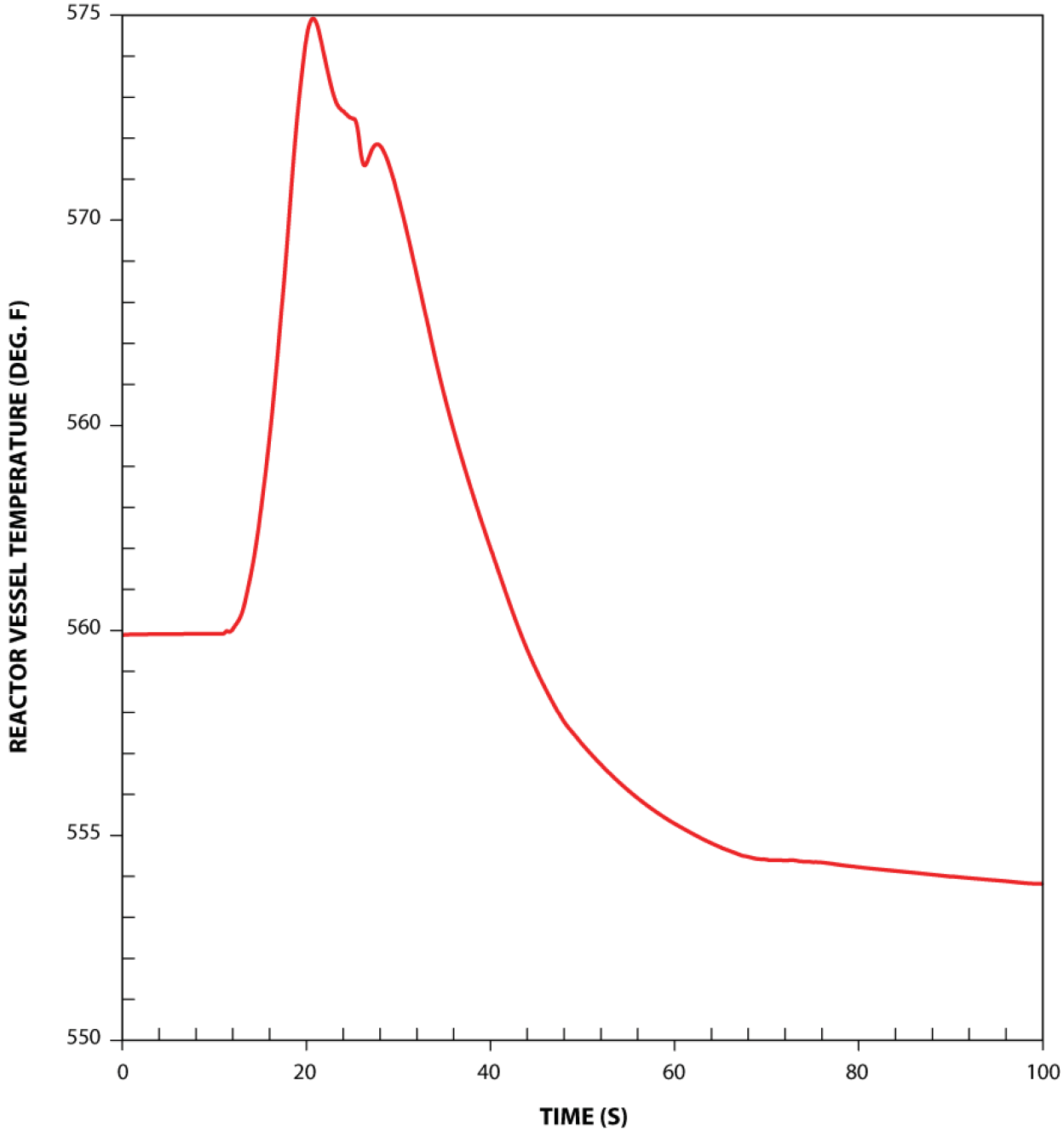

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FIGURE 15.2.3-4 Loss of Condenser Vacuum (RCS Overpressure Case) Vessel Average Temperature vs. Time

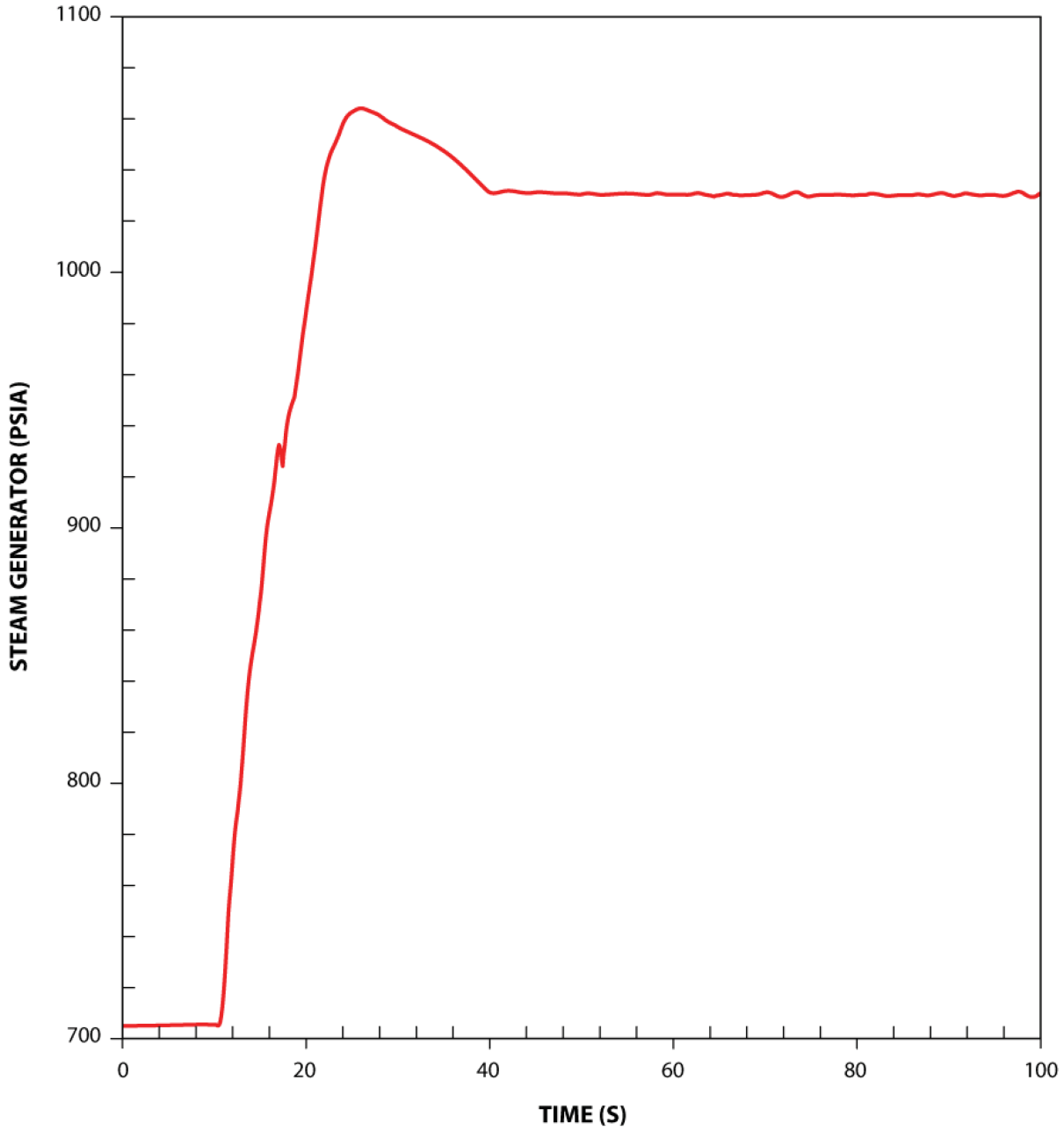

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FIGURE 15.2.3-5 Loss of Condenser Vacuum (RCS Overpressure Case) Steam Generator Pressure vs. Time

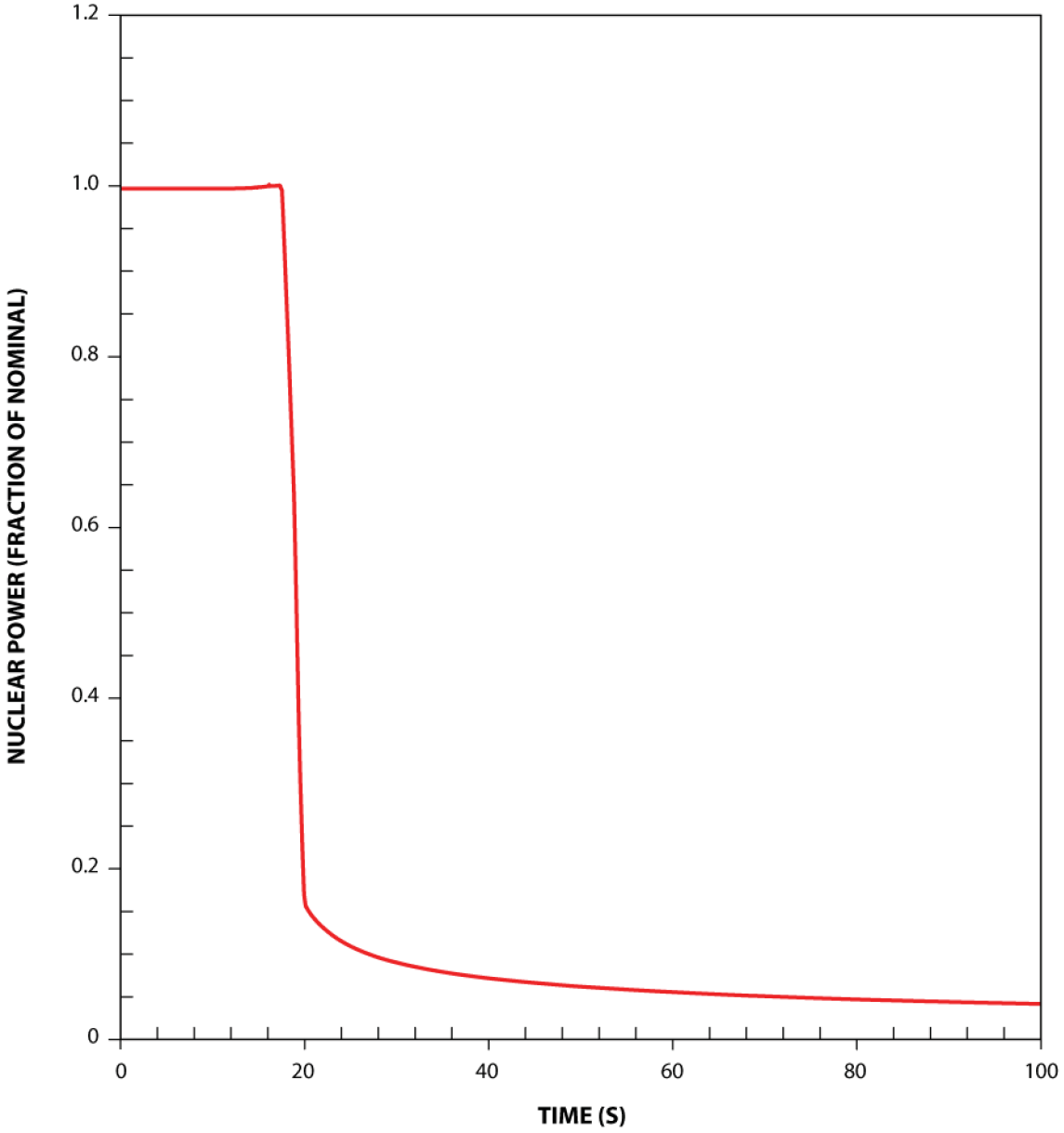

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FIGURE 15.2.3-6 Loss of Condenser Vacuum (DNBR Case) Nuclear Power vs. Time

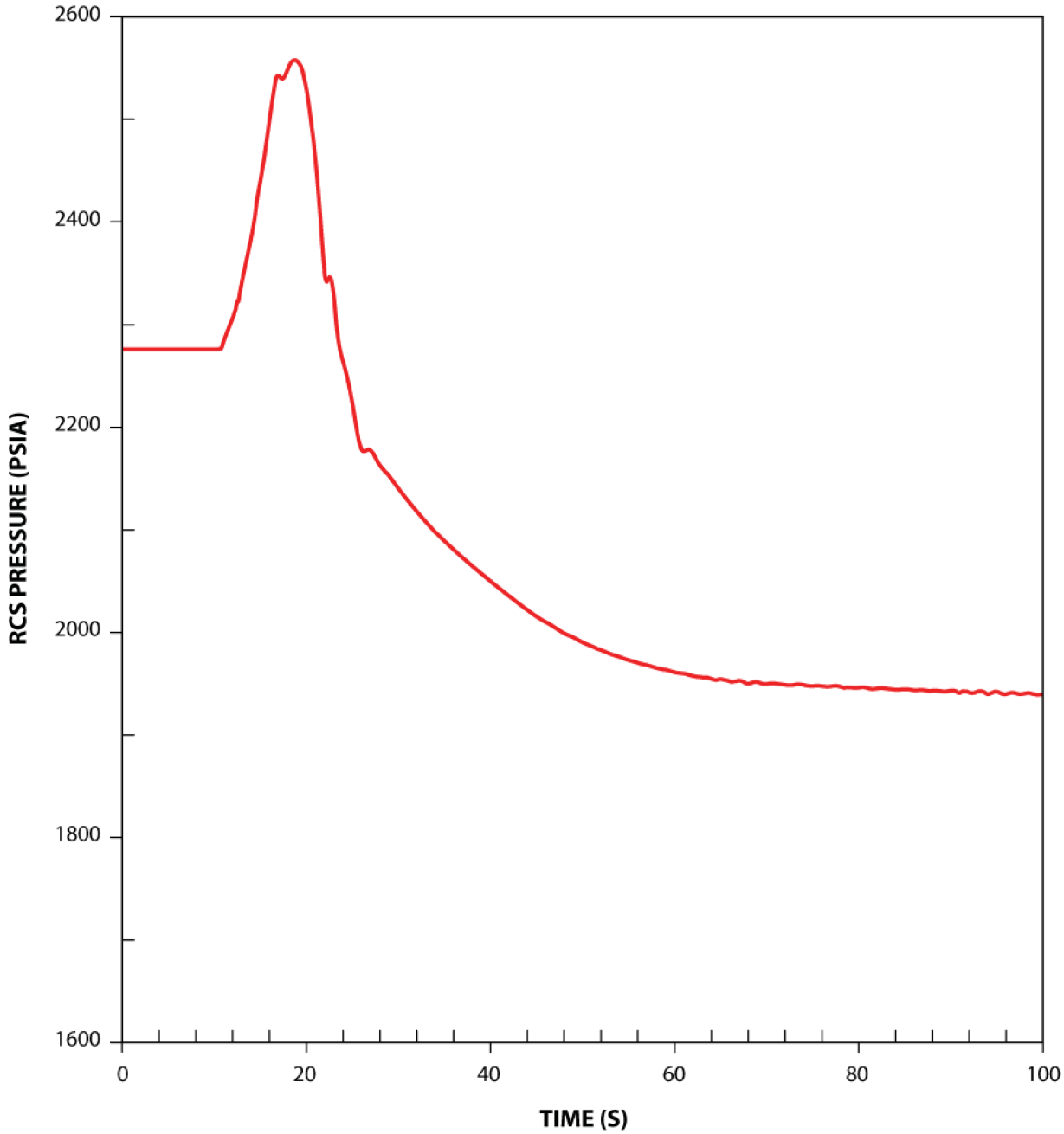

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FIGURE 15.2.3-7 Loss of Condenser Vacuum (DNBR Case) RCS Pressure (Vessel Lower Plenum) vs. Time

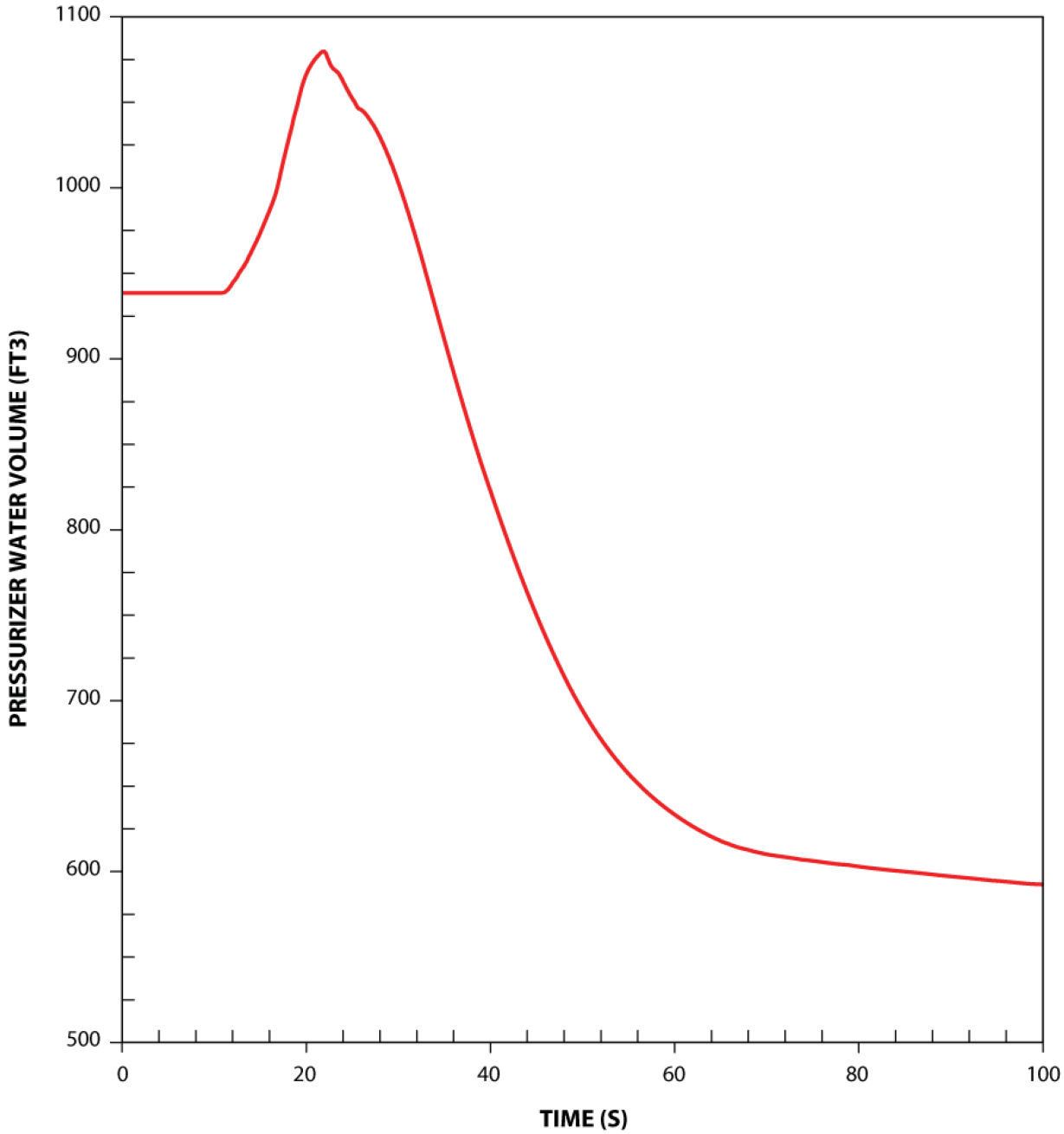

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FIGURE 15.2.3-8 Loss of Condenser Vacuum (DNBR Case) Pressurizer Water Volume vs. Time

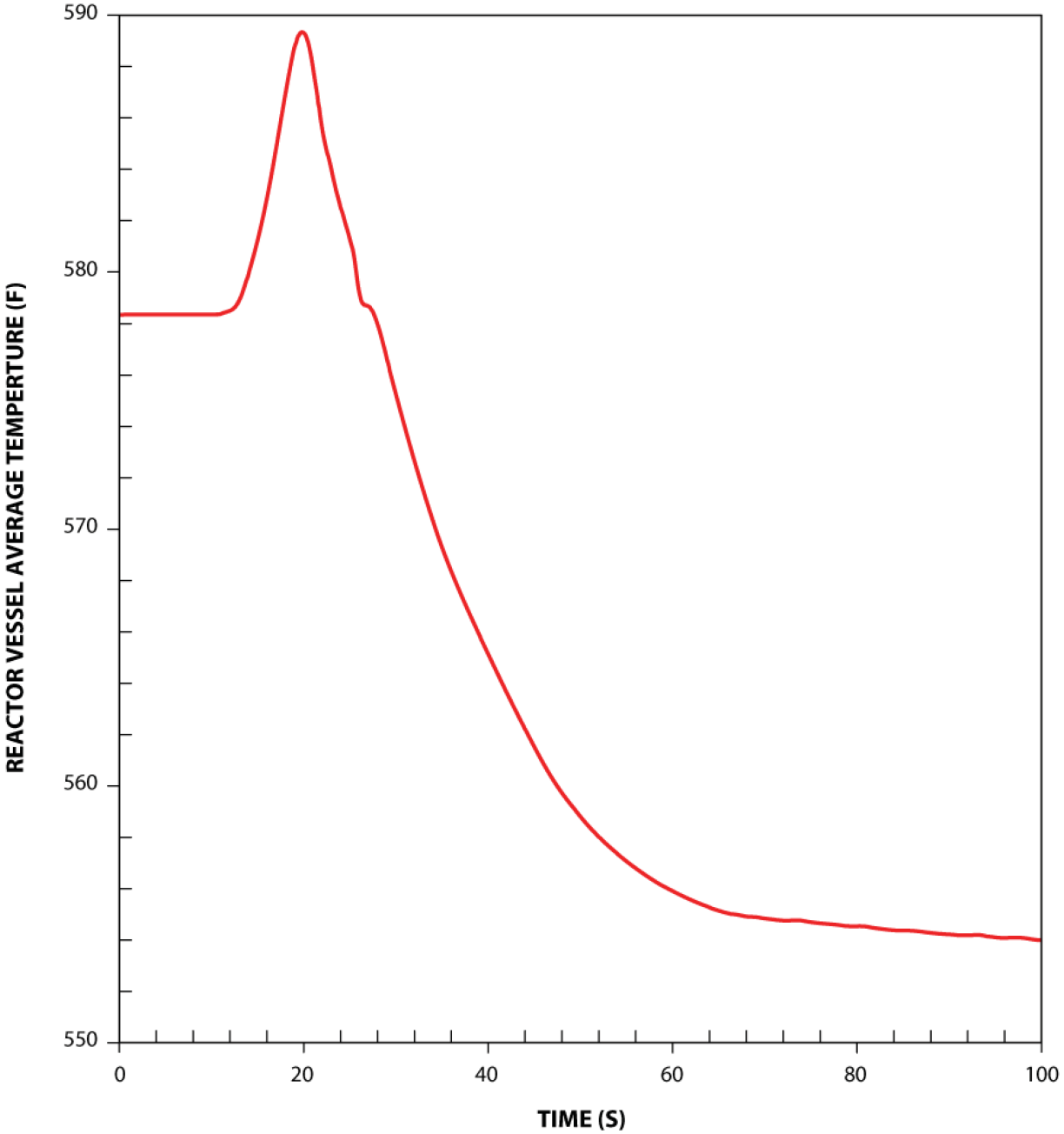

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FIGURE 15.2.3-9 Loss of Condenser Vacuum (DNBR Case) Vessel Average Temperature vs. Time

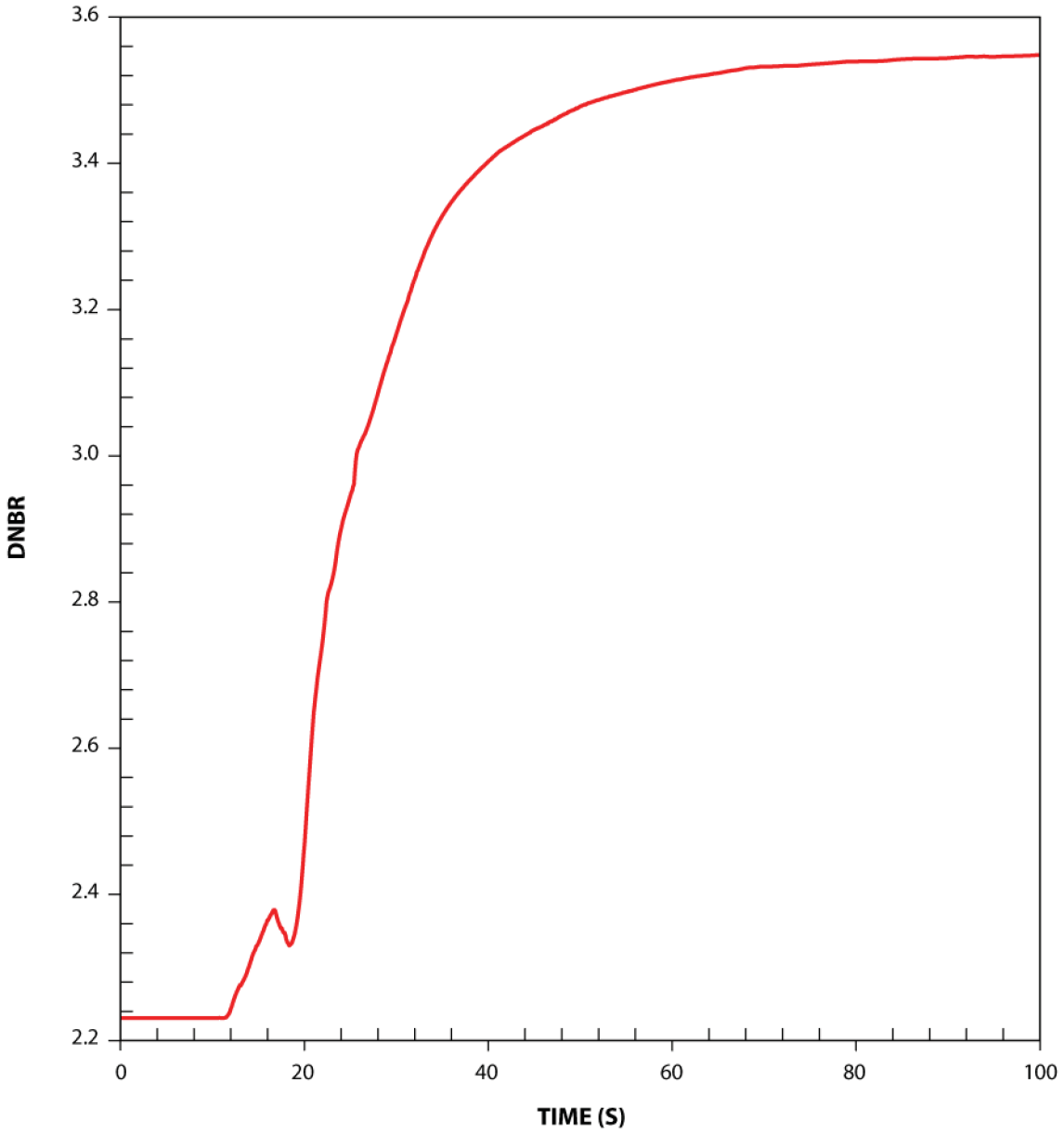

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FIGURE 15.2.3-10 Loss of Condenser Vacuum (DNBR Case) DNBR vs. Time

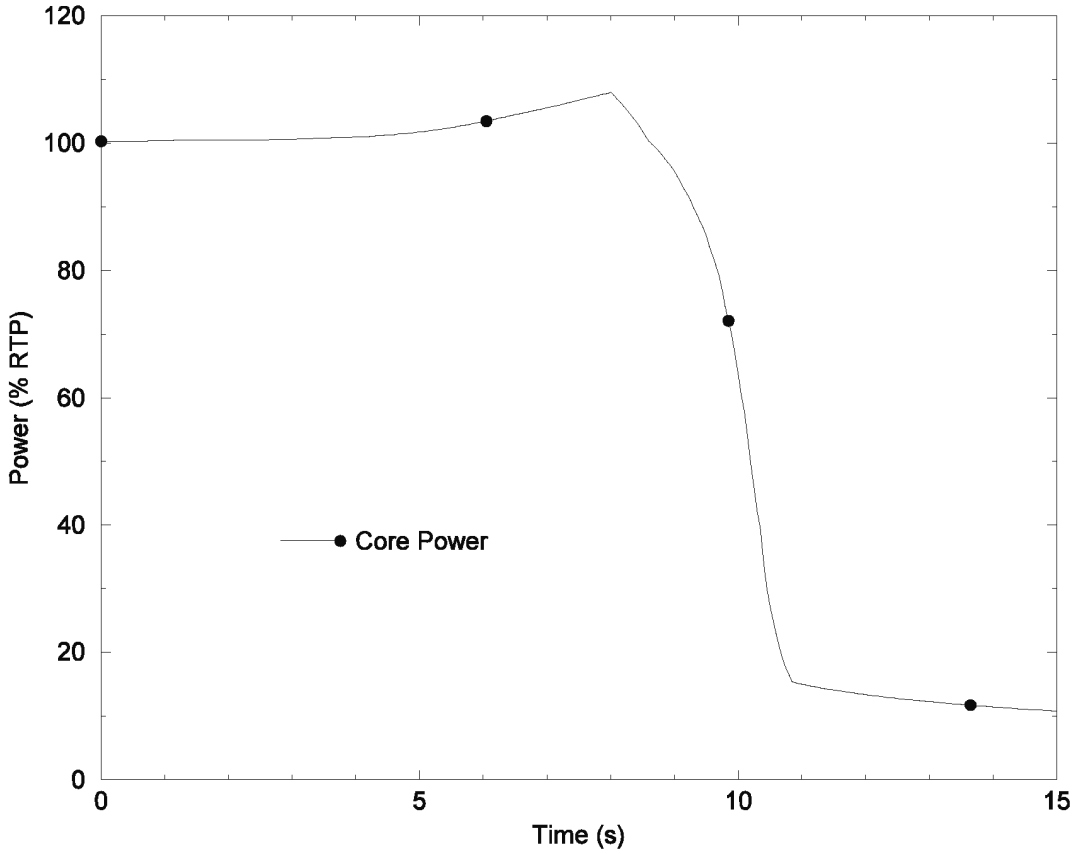

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Figure 15.2.3-11
Loss of Condenser Vacuum
(AREVA SAFDLs):
Reactor Power vs. Time

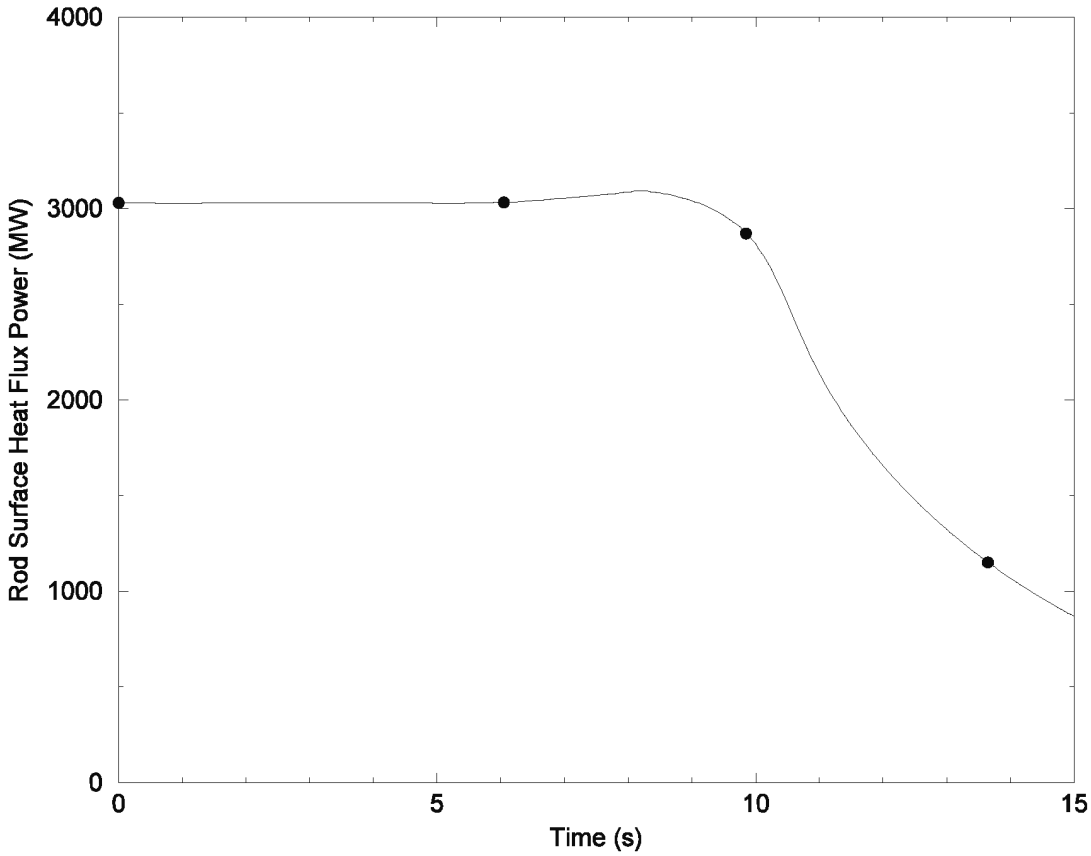

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Figure 15.2.3-12
Loss of Condenser Vacuum
(AREVA SAFDLs):
Total Core Heat Flux Power vs. Time

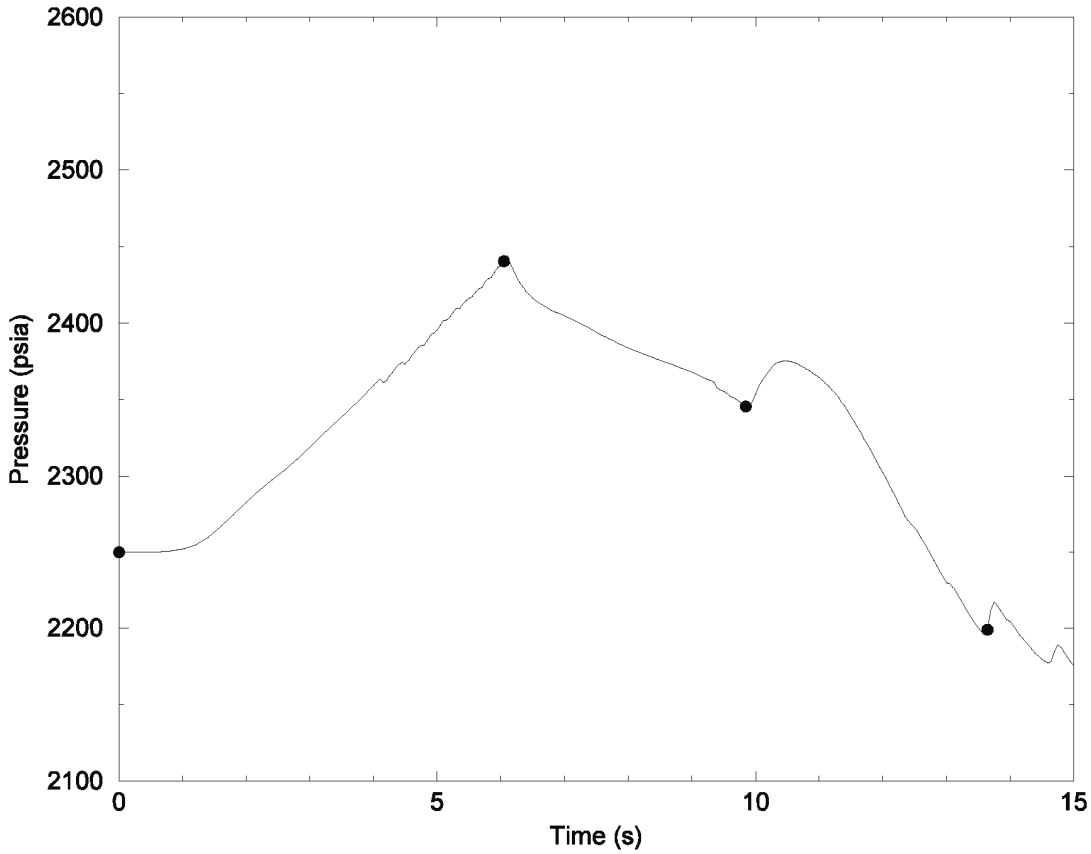

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Figure 15.2.3-13
Loss of Condenser Vacuum
(AREVA SAFDLs):
Pressurizer Pressure vs. Time

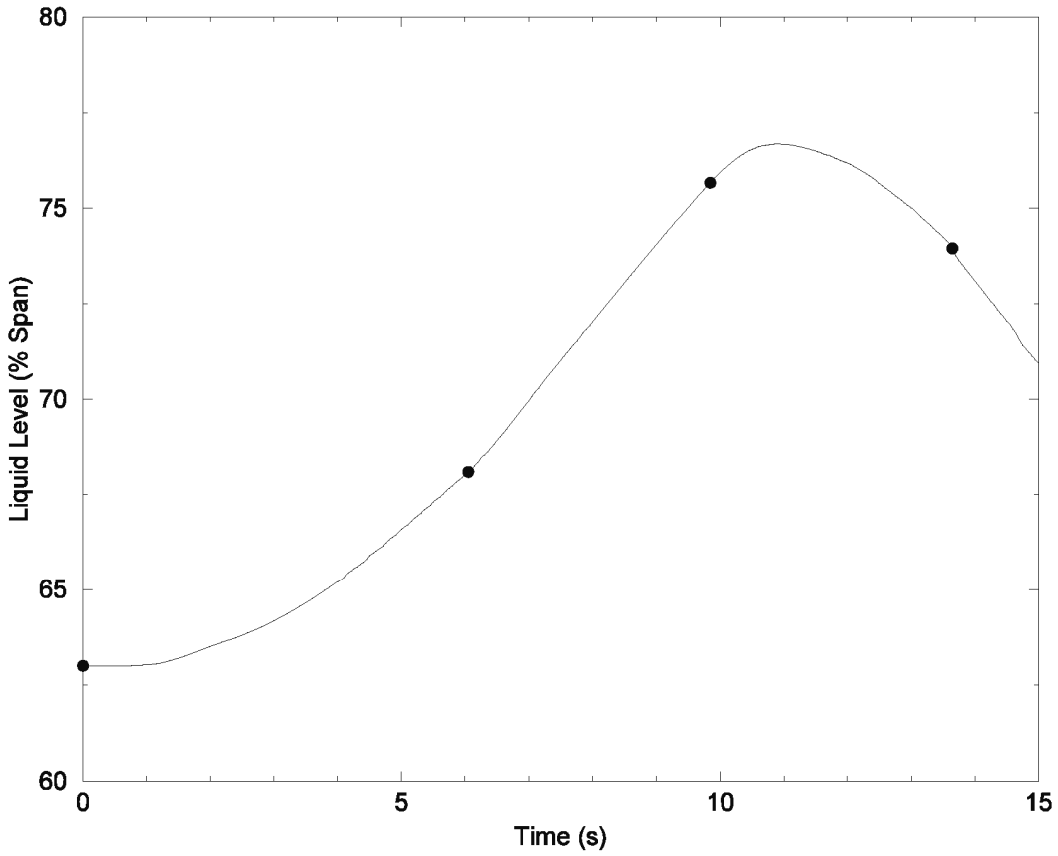

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Figure 15.2.3-14
Loss of Condenser Vacuum
(AREVA SAFDLs):
Pressurizer Liquid Level vs. Time

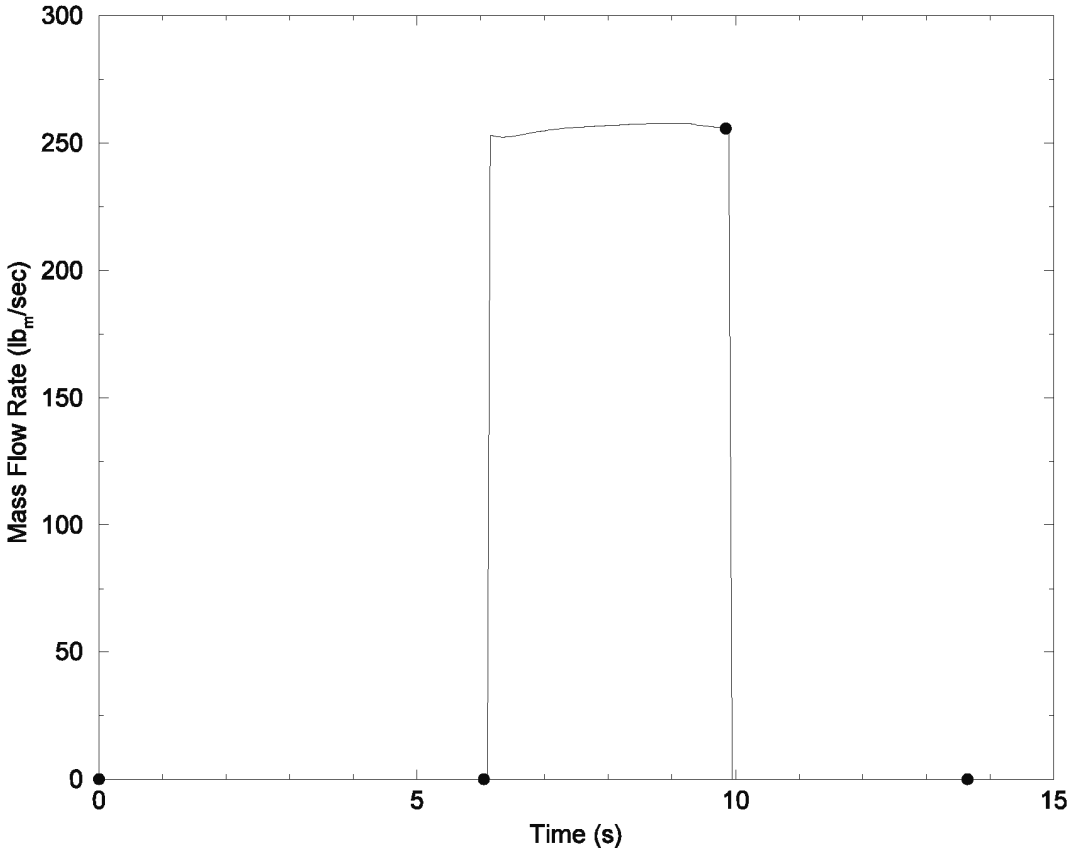

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Figure 15.2.3-15
Loss of Condenser Vacuum
(AREVA SAFDLs):
Pressurizer PORVs Flow Rate vs. Time

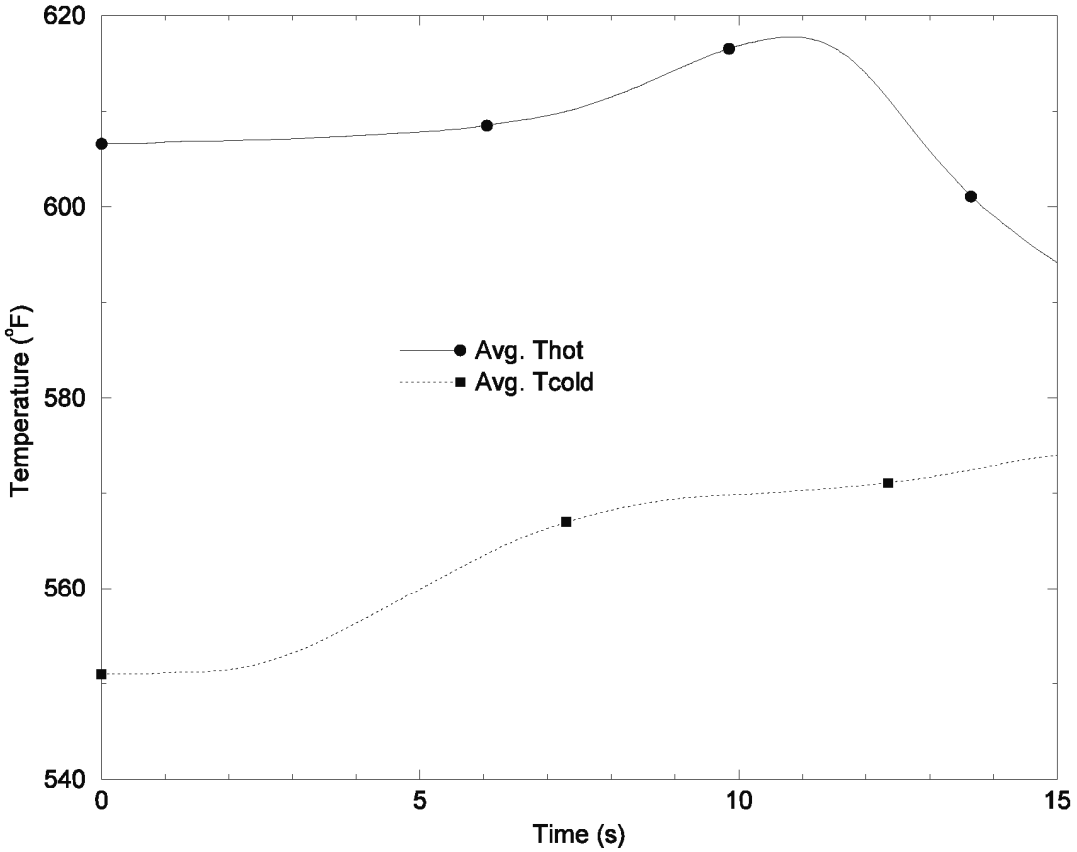

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Figure 15.2.3-16
Loss of Condenser Vacuum
(AREVA SAFDLs):
RCS Loop Temperatures vs. Time

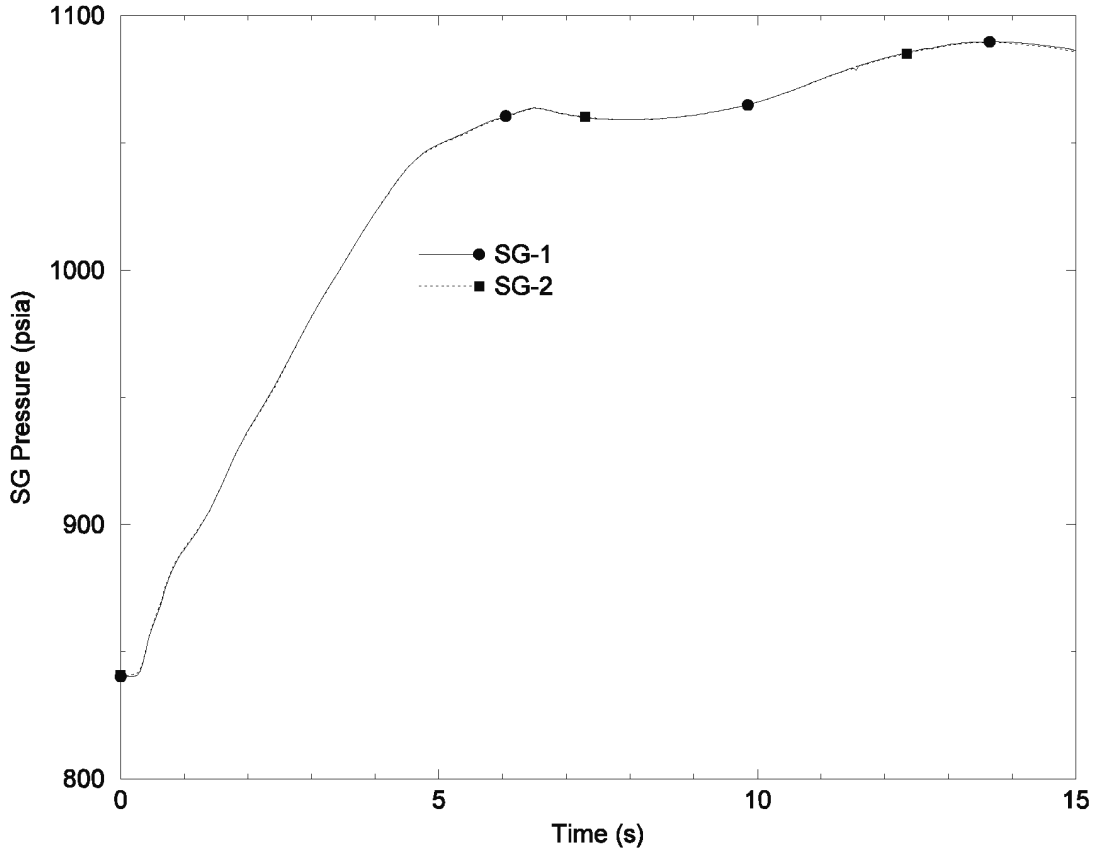

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Figure 15.2.3-17
Loss of Condenser Vacuum
(AREVA SAFDLs):
Steam Generator Pressures vs. Time

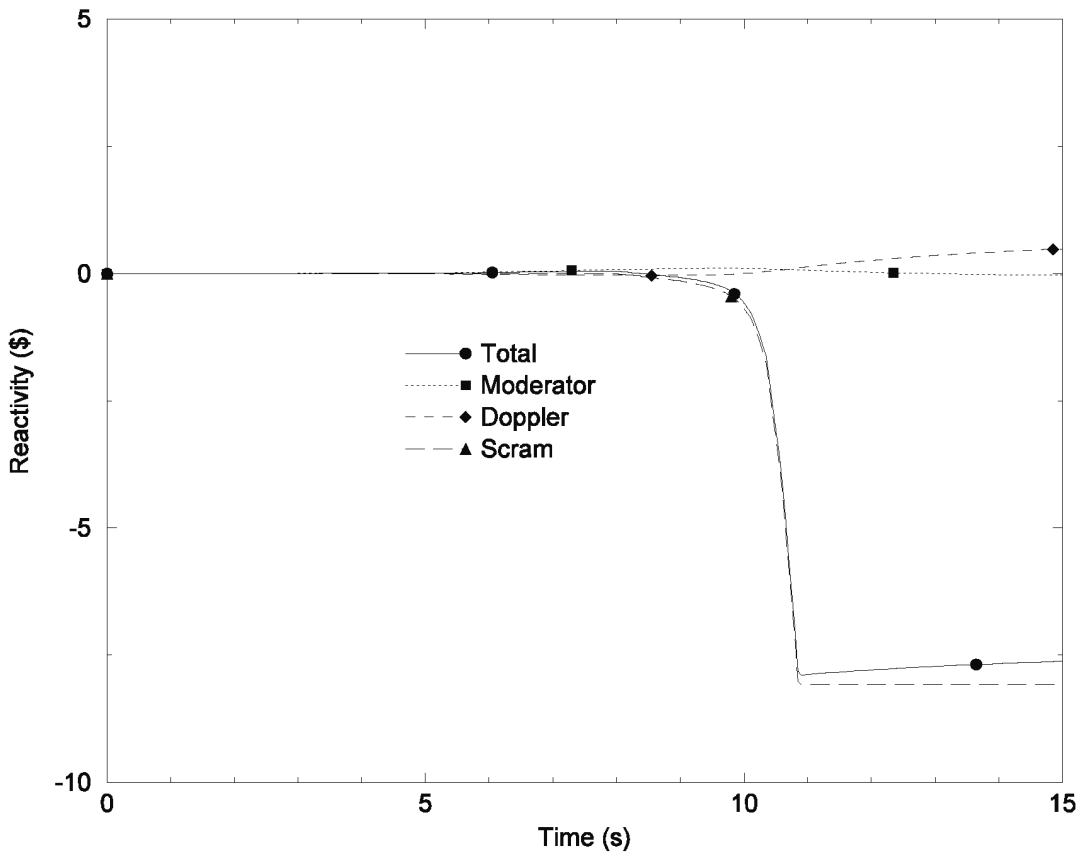

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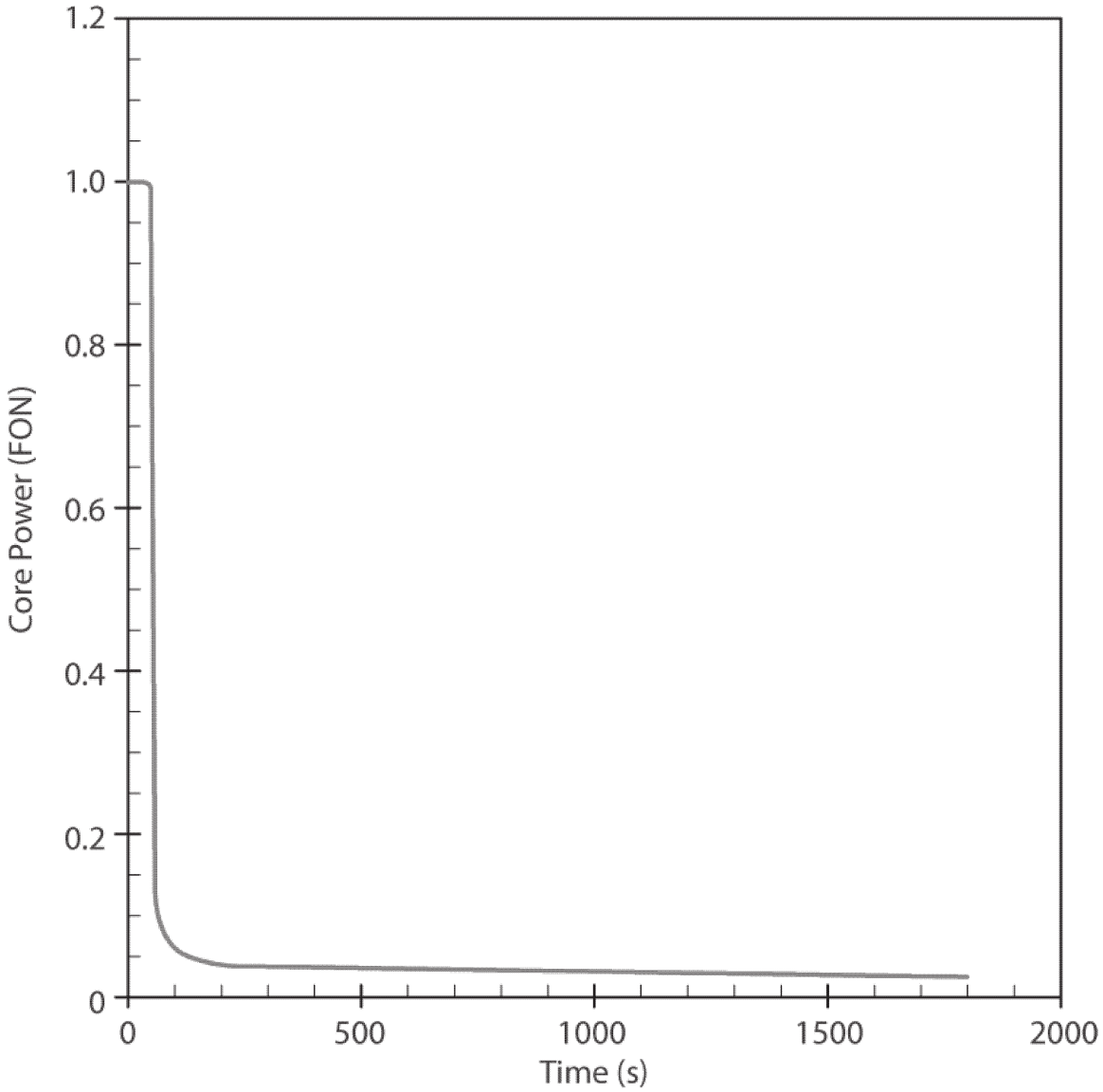
Figure 15.2.3-18
Loss of Condenser Vacuum
(AREVA SAFDLs):
Reactivity Feedback vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.7-1 Loss of Normal Feedwater (Subcooling Case) Core Power vs. Time

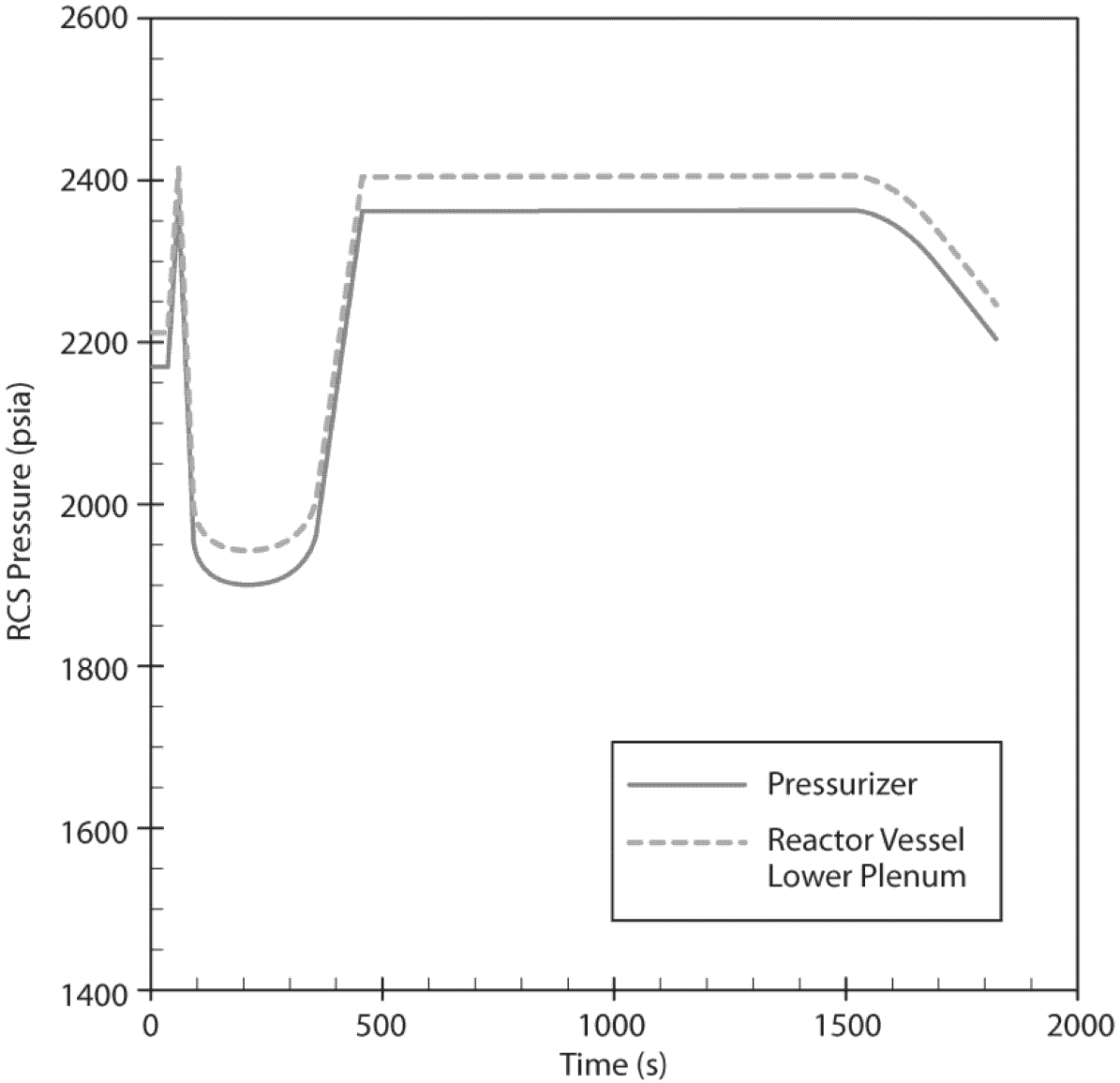


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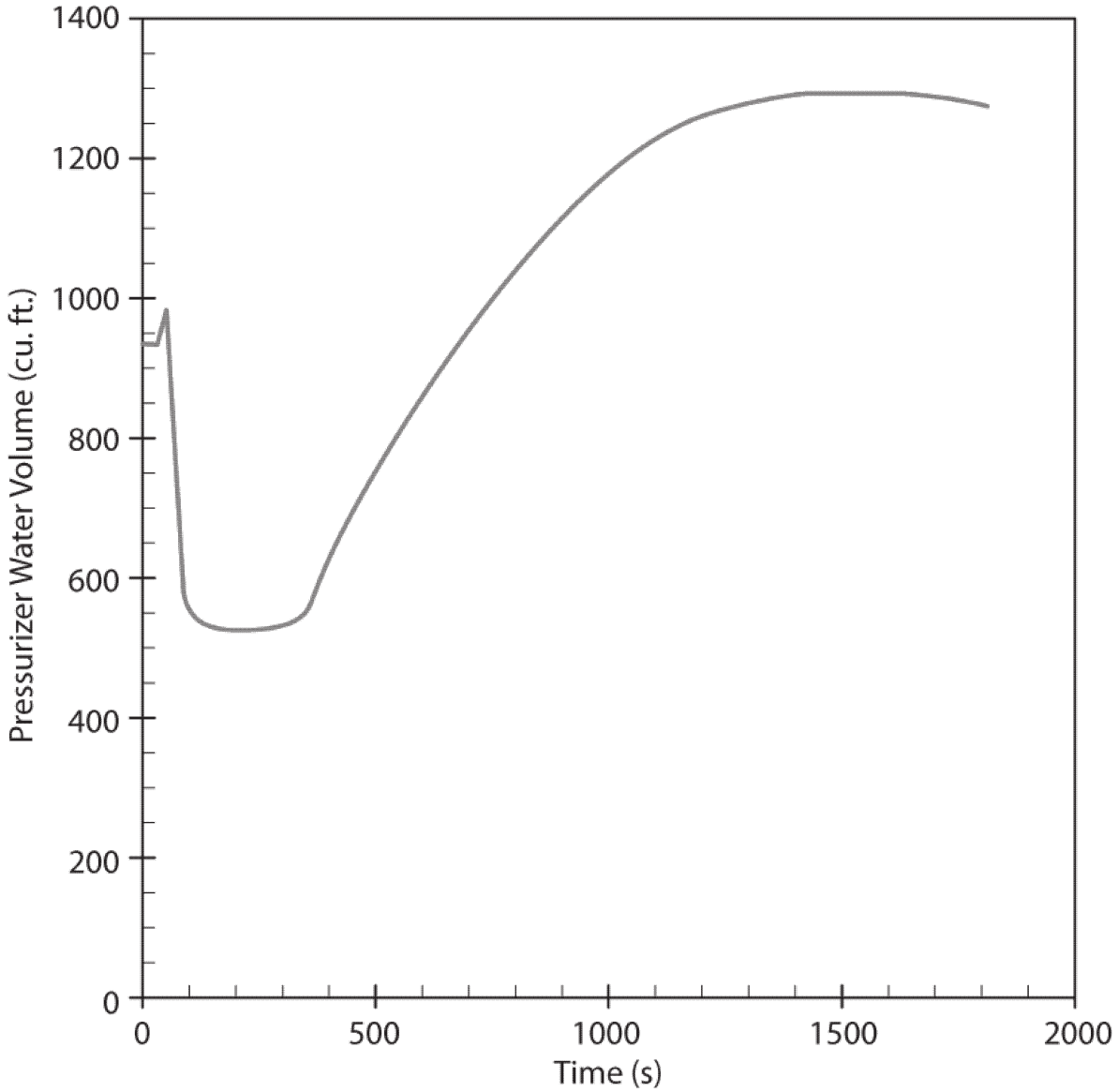
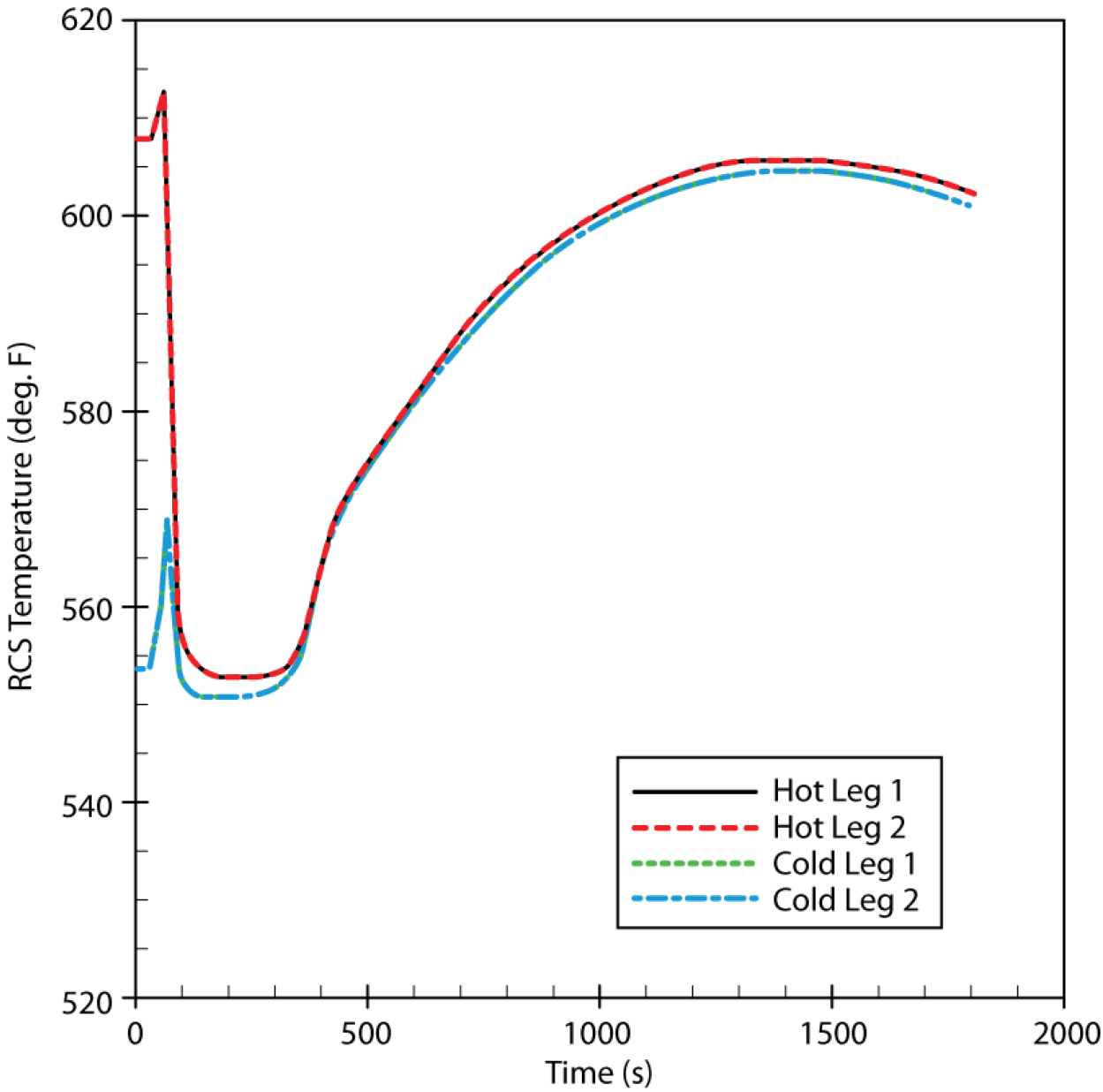
FIGURE 15.2.7-2 Loss of Normal Feedwater (Subcooling Case) RCS Pressure vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.7-3 Loss of Normal Feedwater (Subcooling Case) Pressurizer Liquid Volume vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.7-4 Loss of Normal Feedwater (Subcooling Case) RCS Loop Temperatures vs. Time

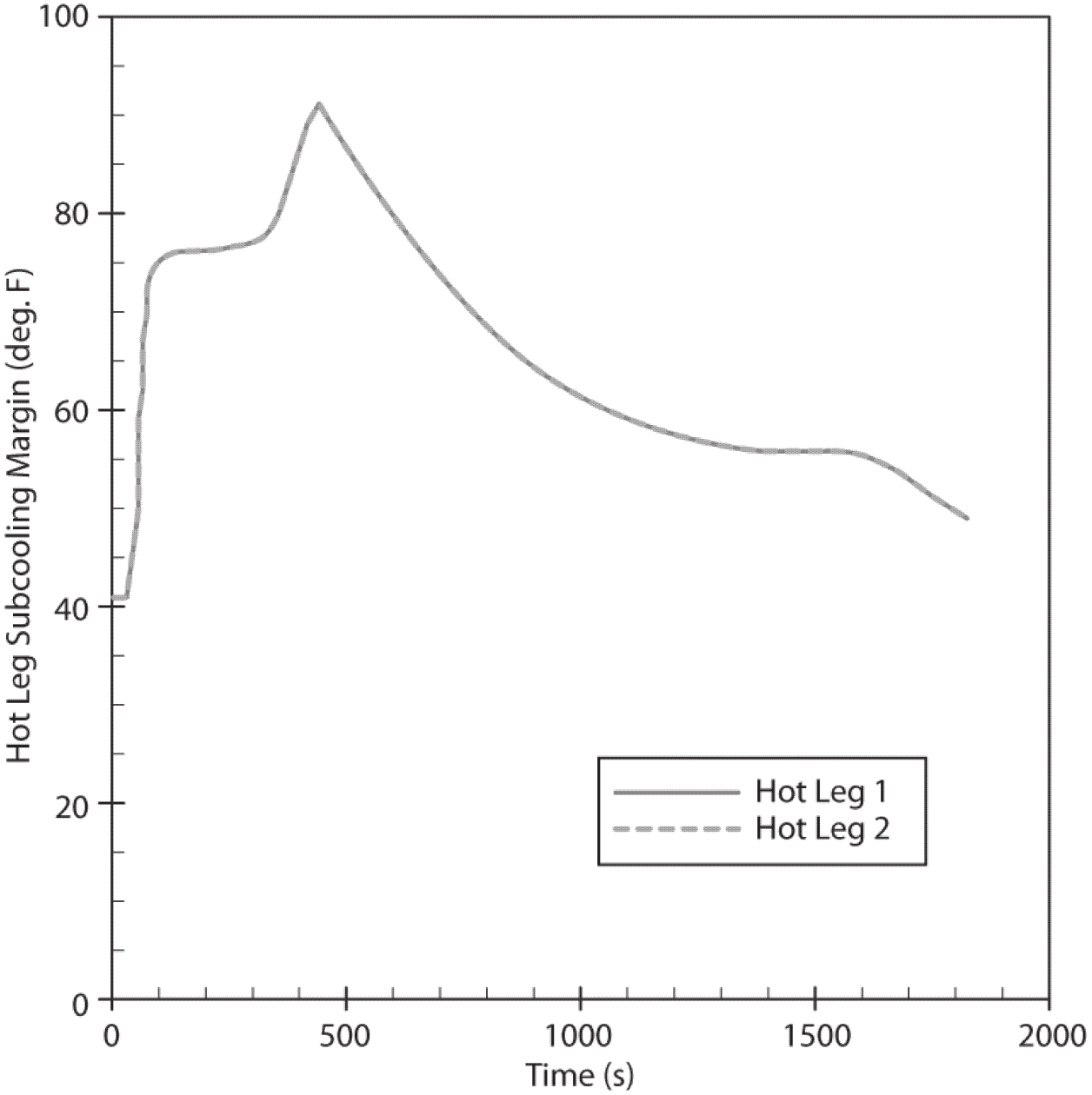


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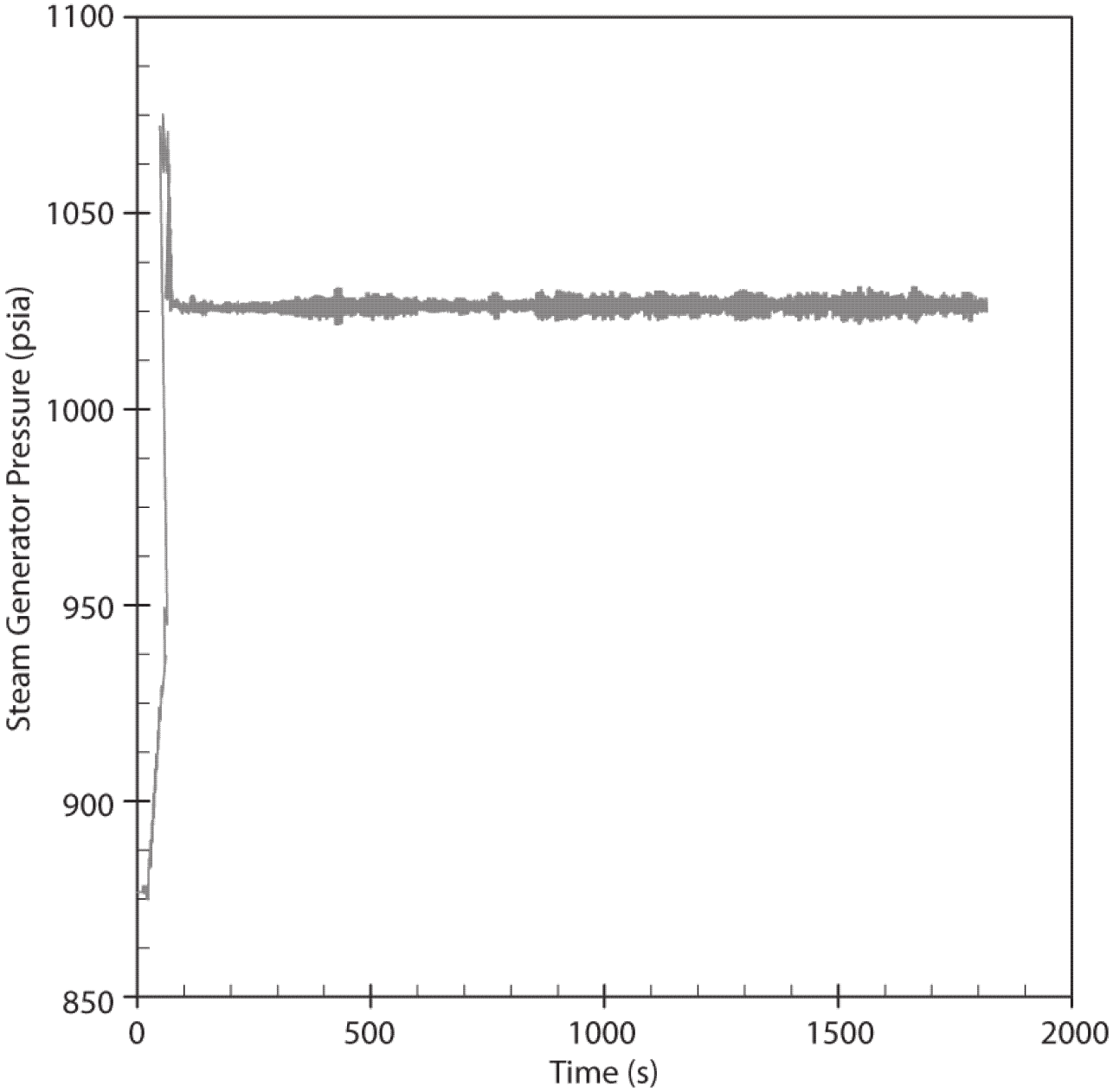
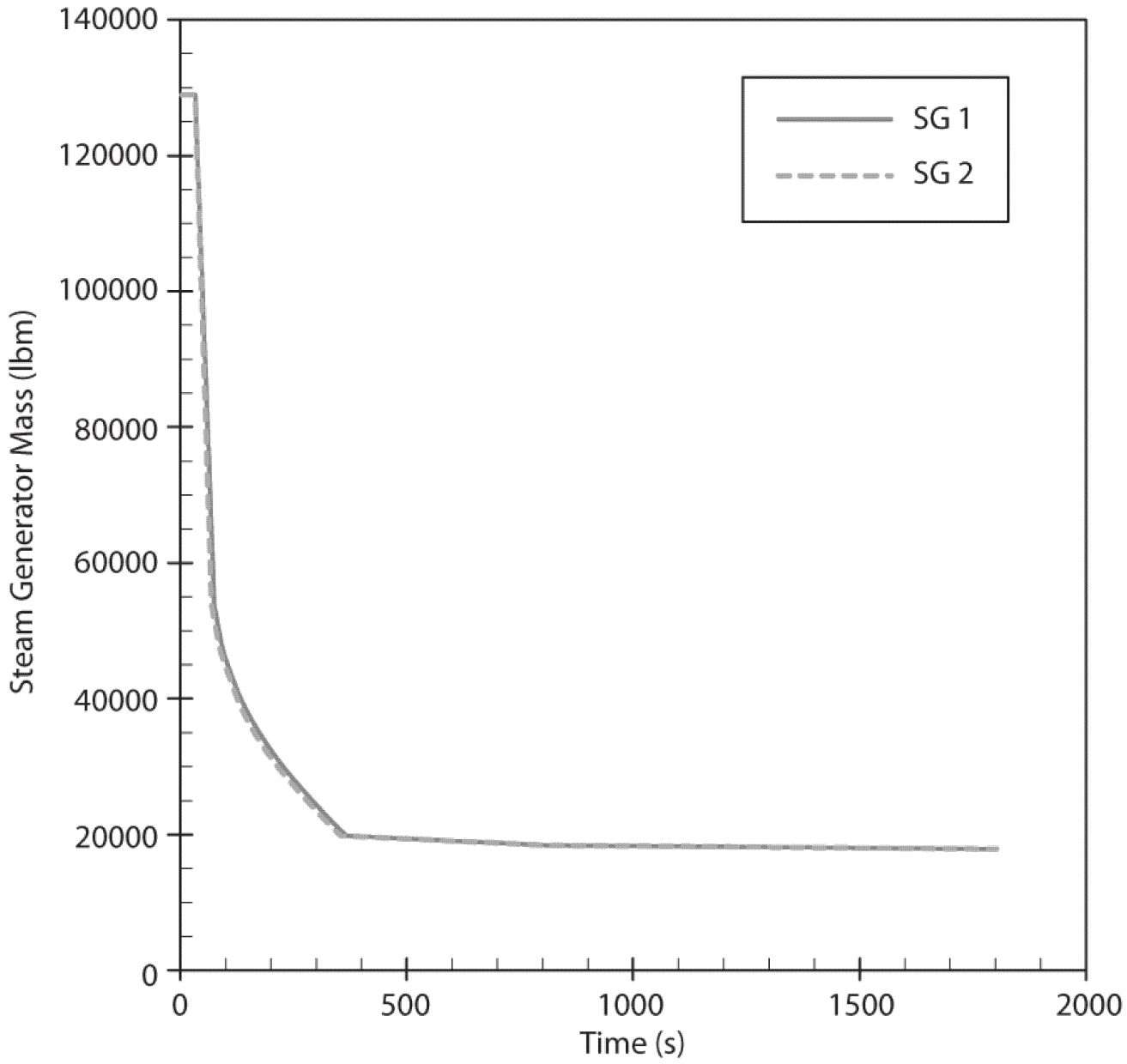
FIGURE 15.2.7-5 Loss of Normal Feedwater (Subcooling Case) Hot Leg Subcooling Margin vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.7-6 Loss of Normal Feedwater (Subcooling Case) Steam Generator Pressure vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.7-7 Loss of Normal Feedwater (Subcooling Case) Steam Generator Mass vs. Time

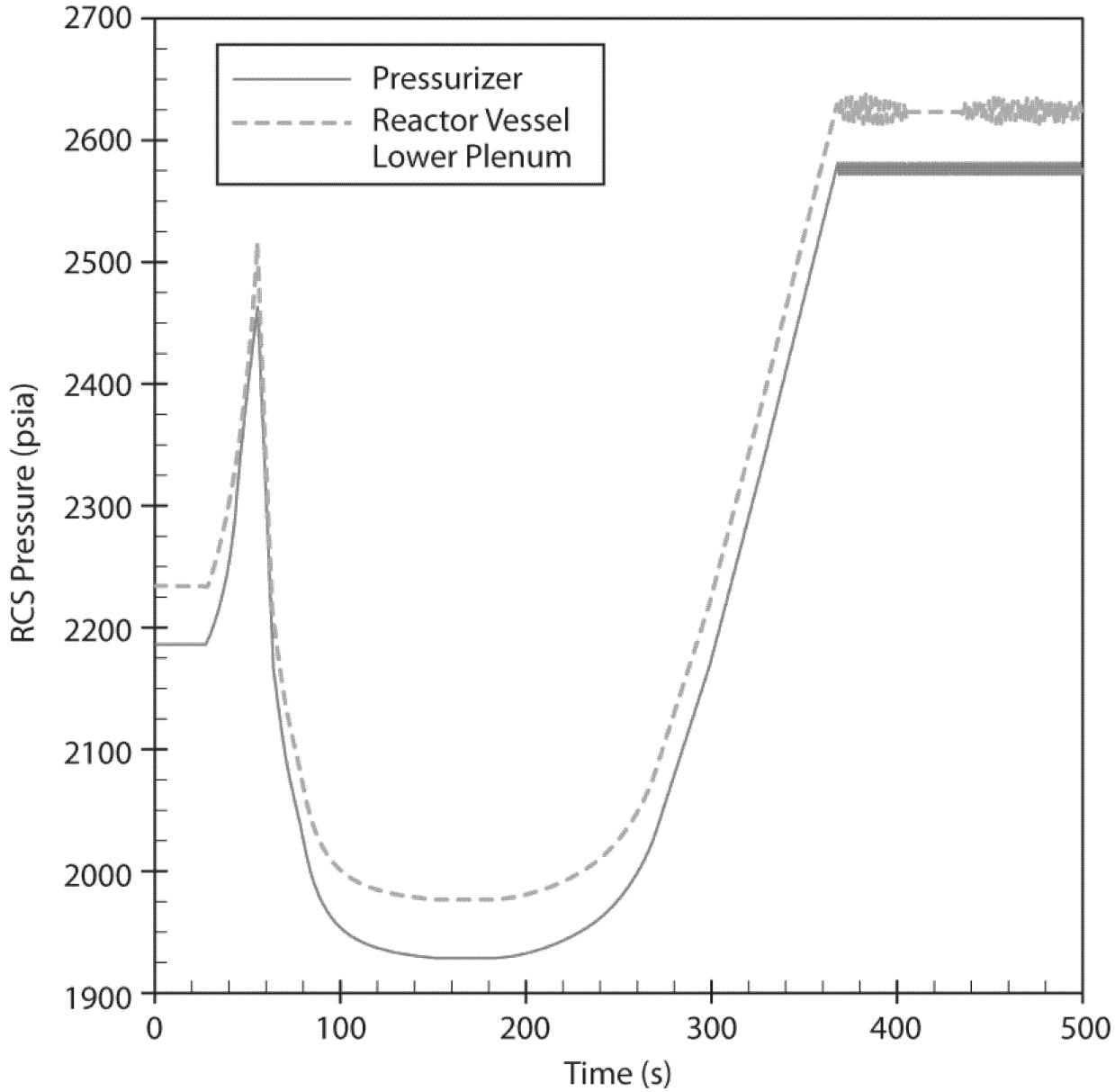


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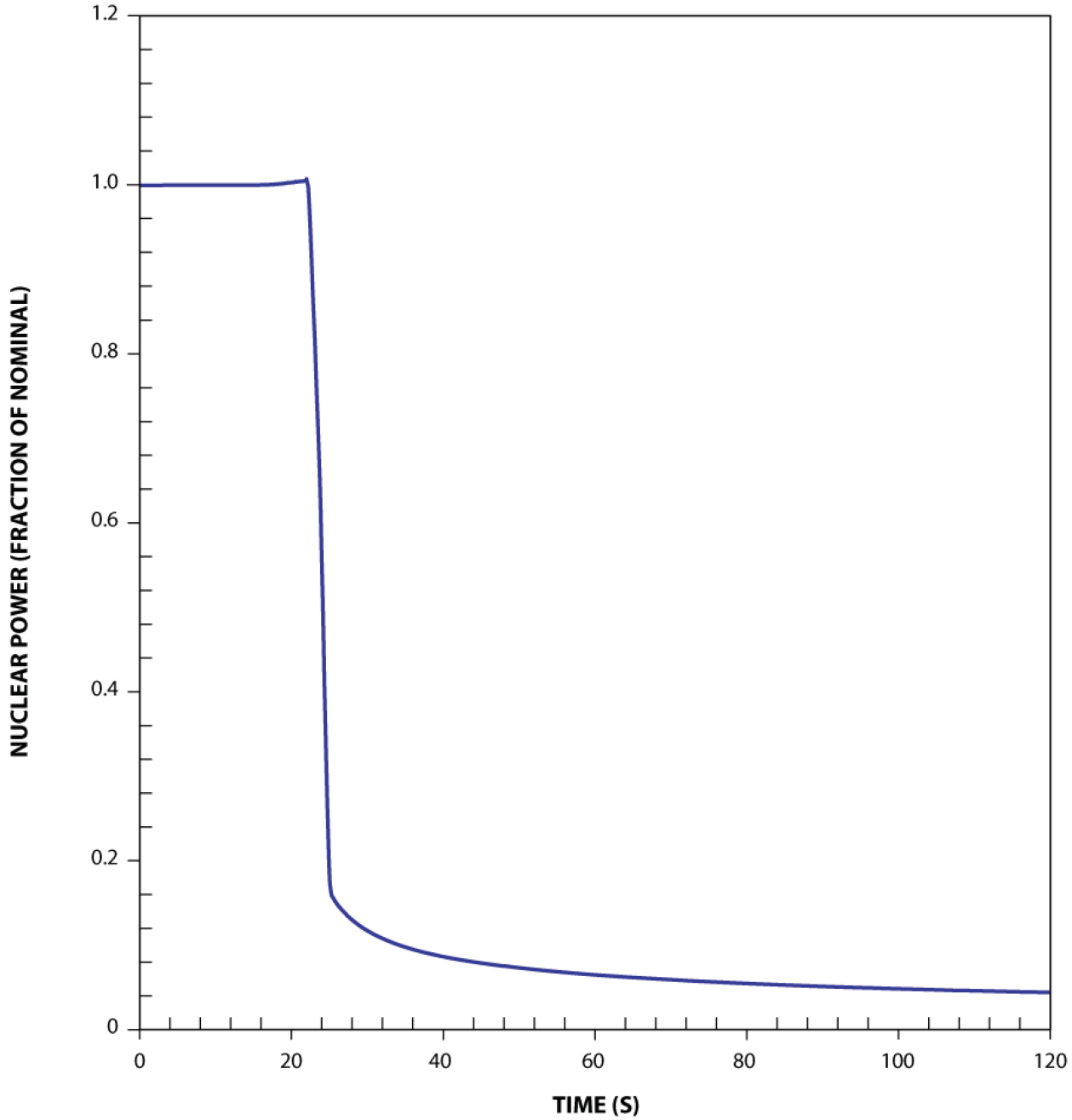
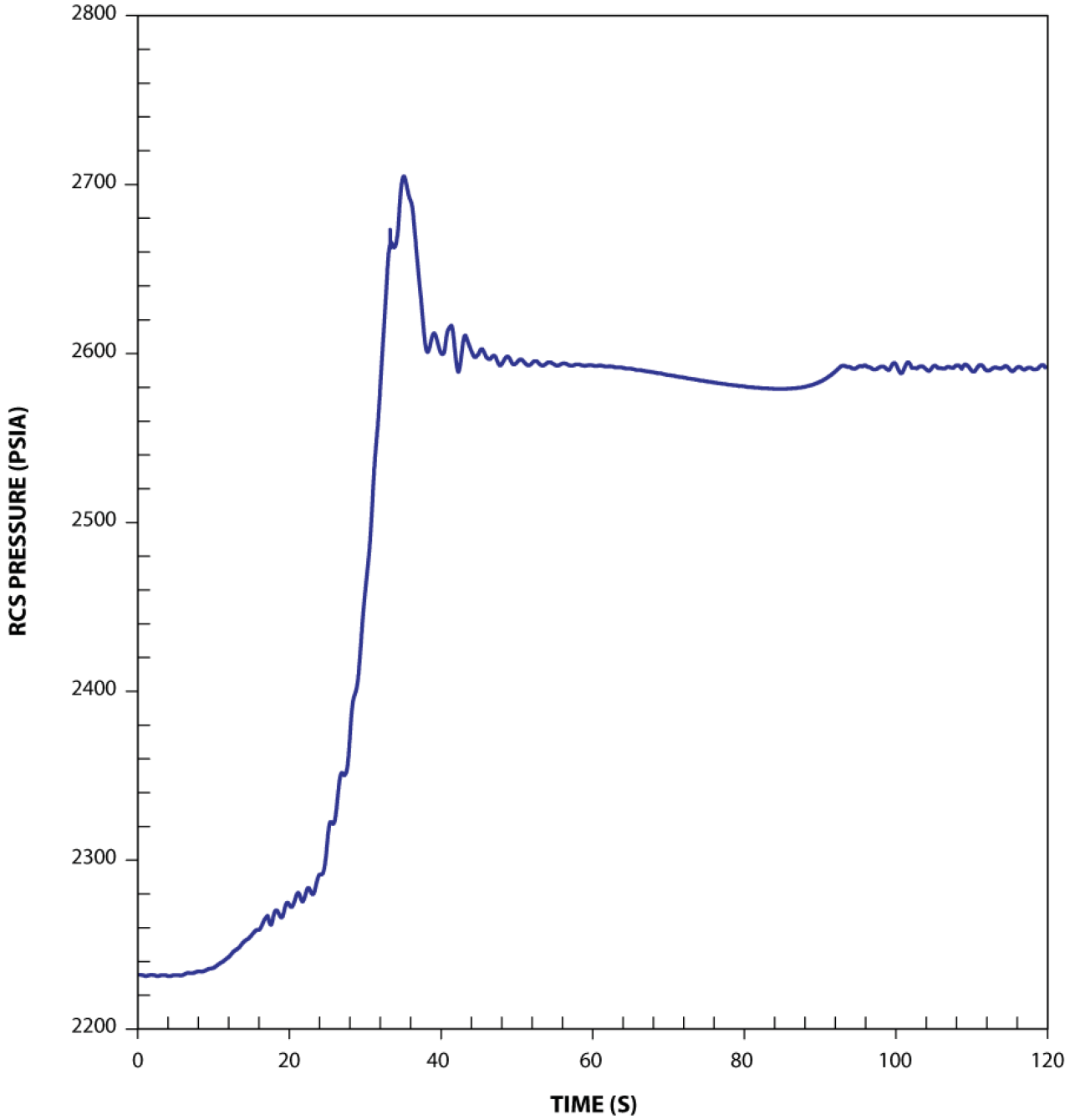
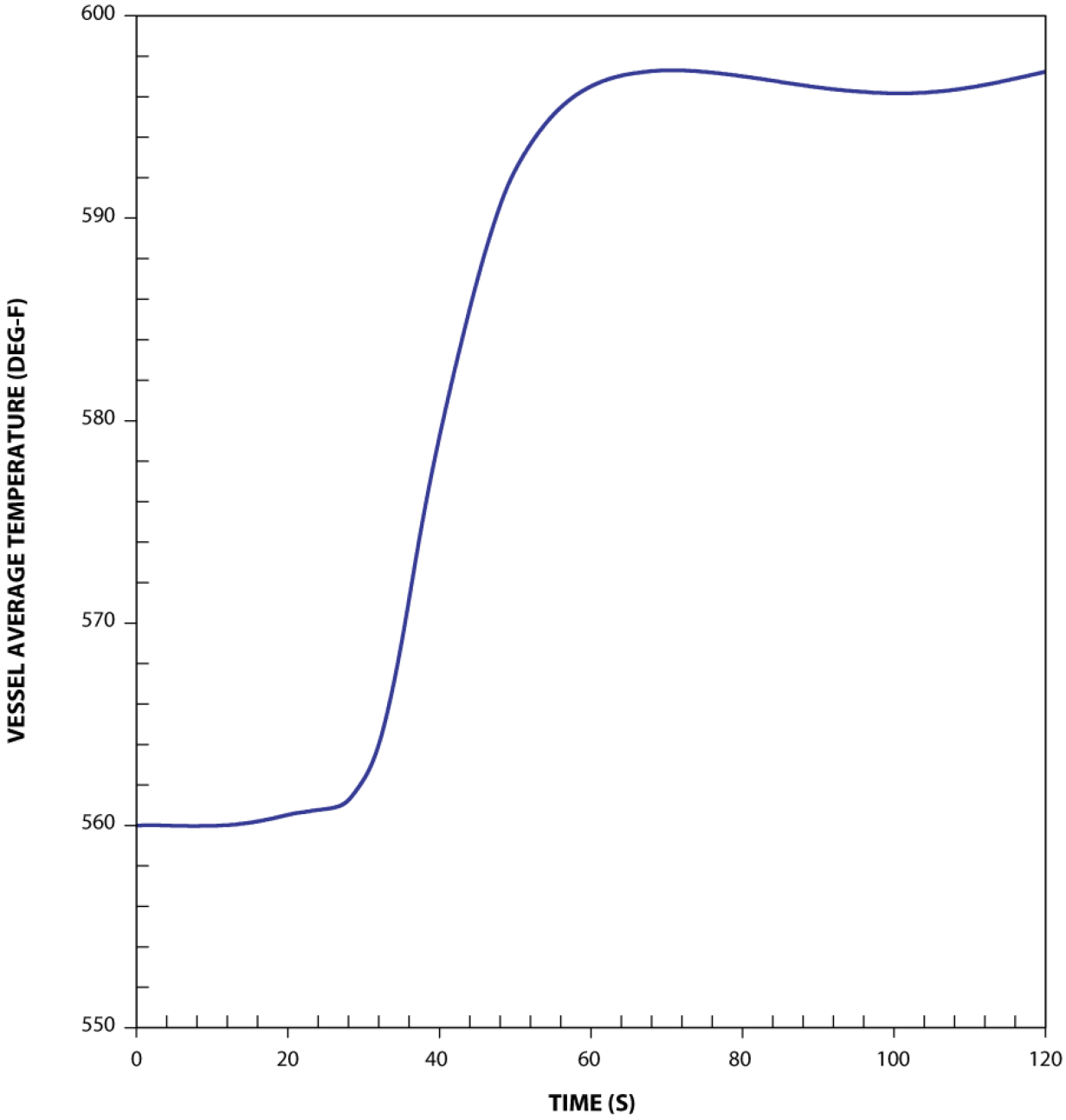
FIGURE 15.2.7-8 Loss of Normal Feedwater (Second Peak RCS Overpressure Case) RCS Pressure vs. Time



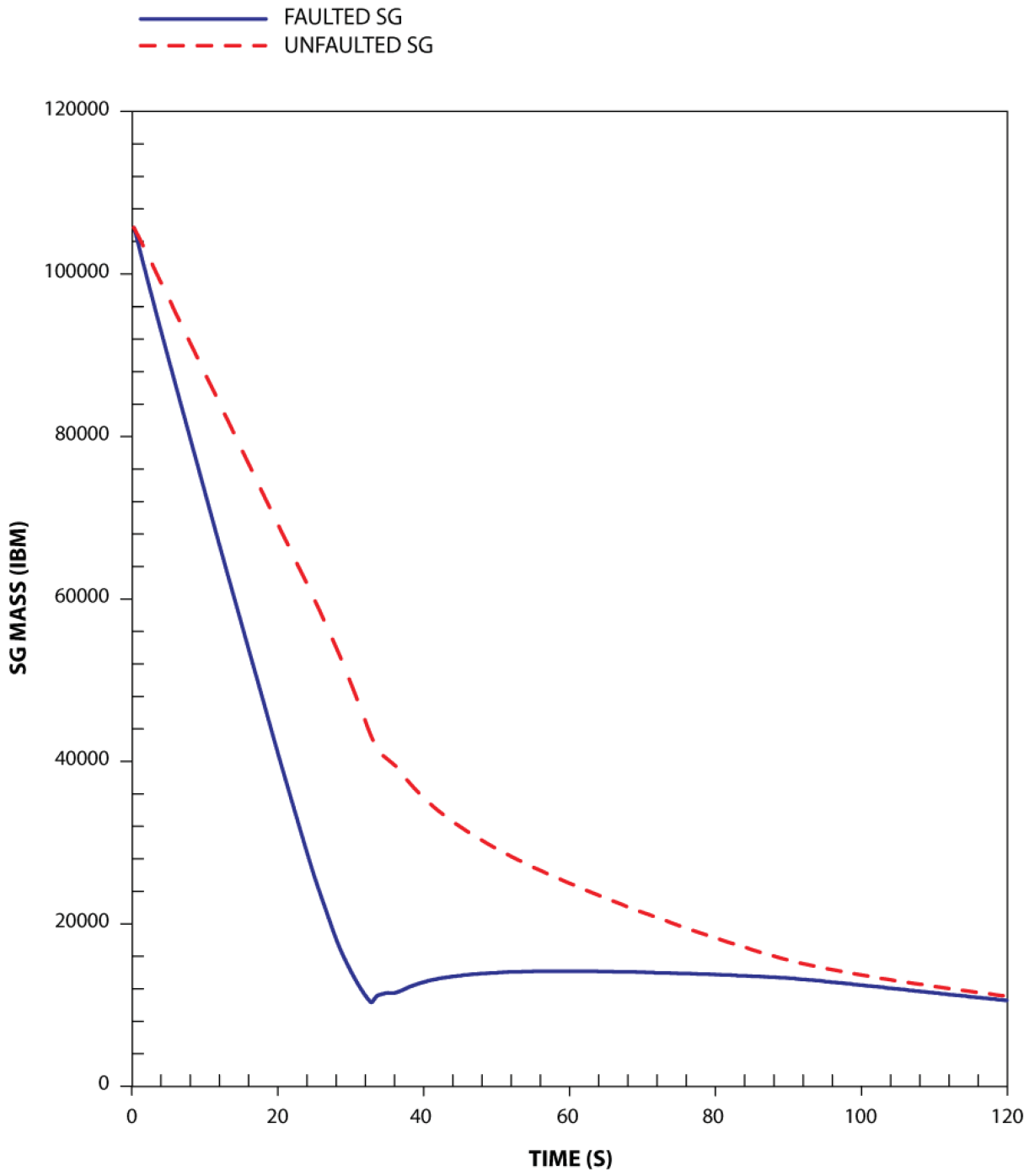
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-1 Feedwater Line Break RCS Overpressure Case Limiting Break Size = 0.21 ft^2 Nuclear Power vs. Time



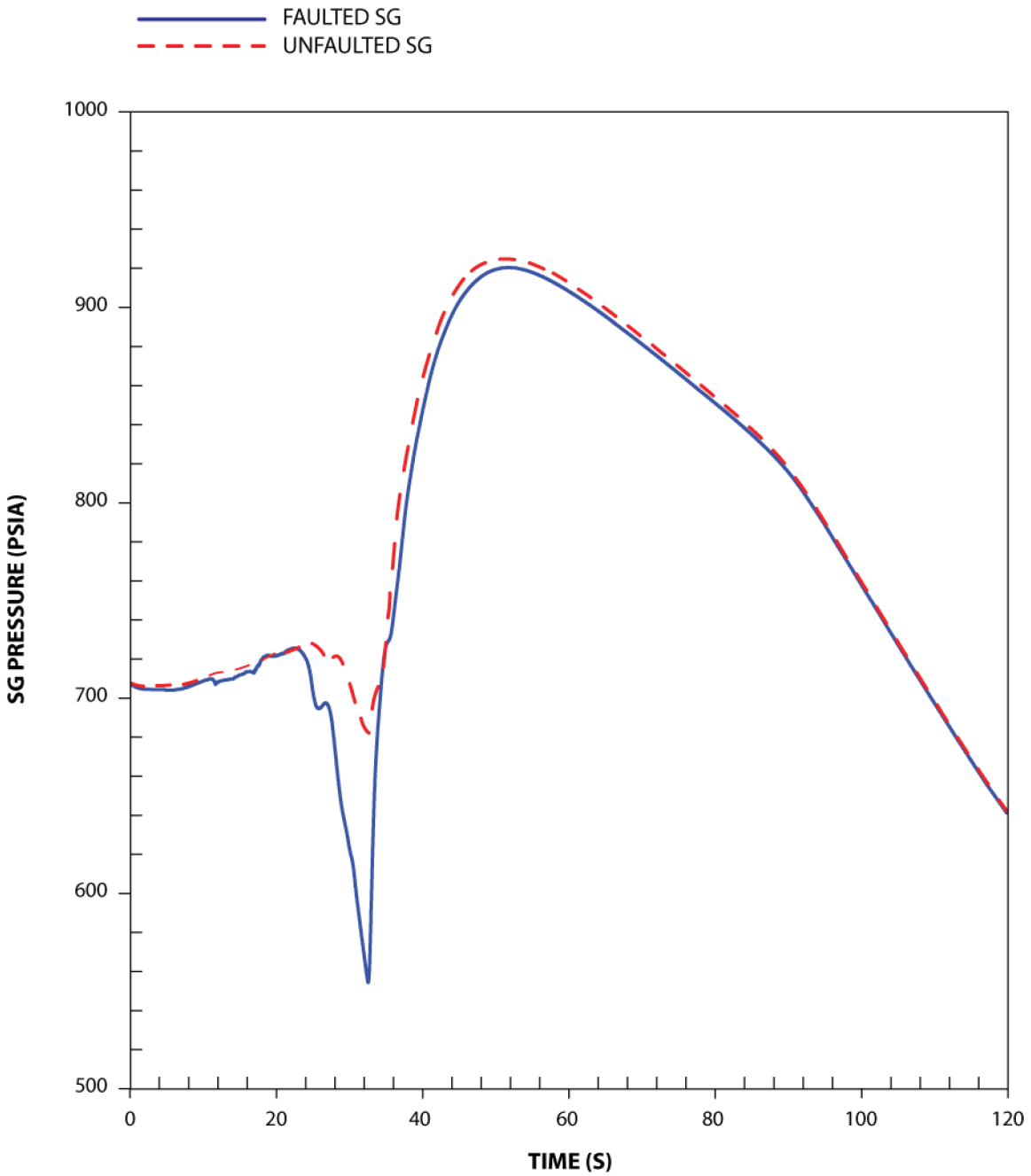
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-2 Feedwater Line Break RCS Overpressure Case Limiting Break Size = 0.210 ft^2 RCS Pressure vs. Time



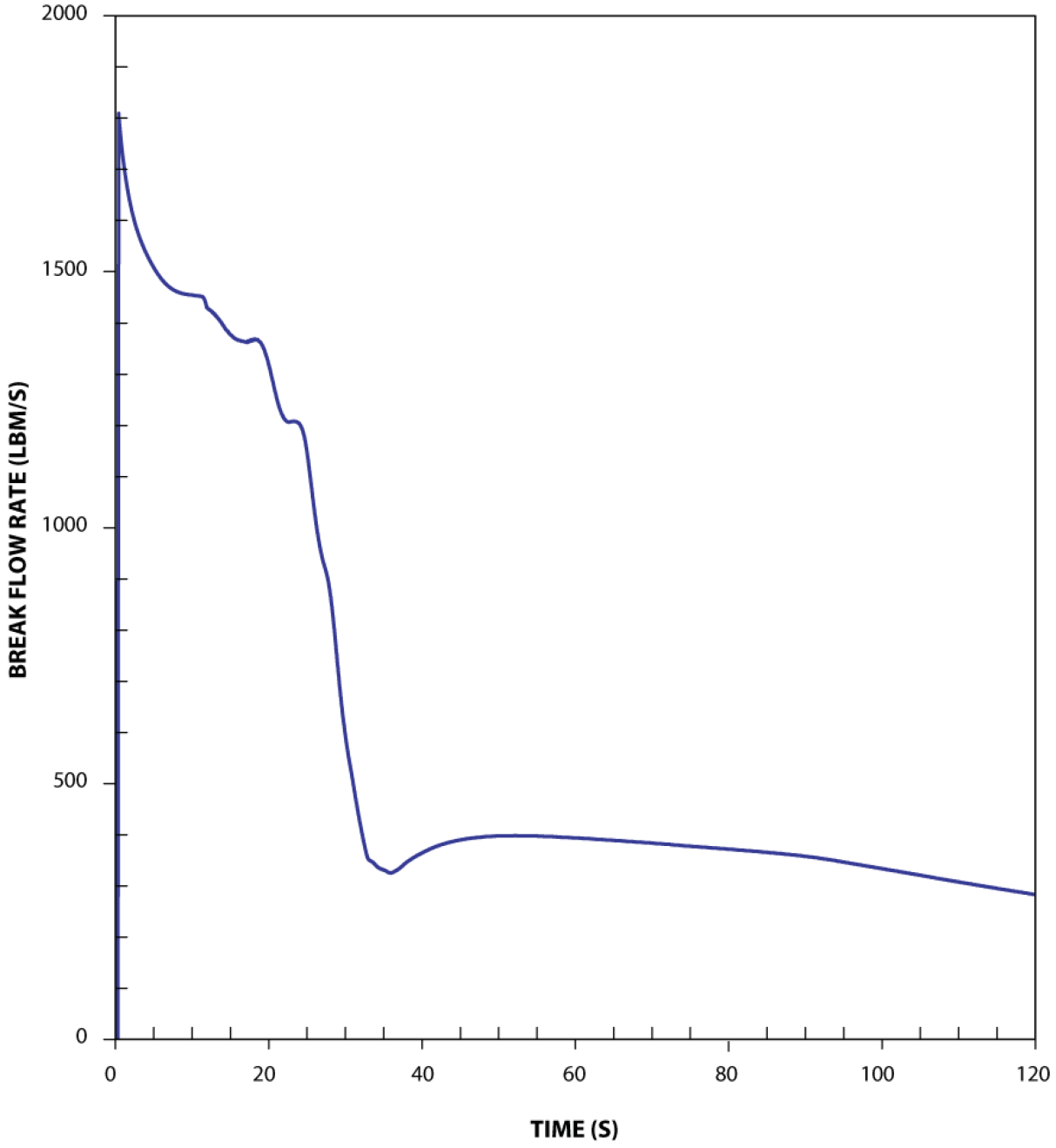
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-3 Feedwater Line Break RCS Overpressure Case Limiting Break Size = 0.21 ft^2 Vessel Average Temperature vs. Time



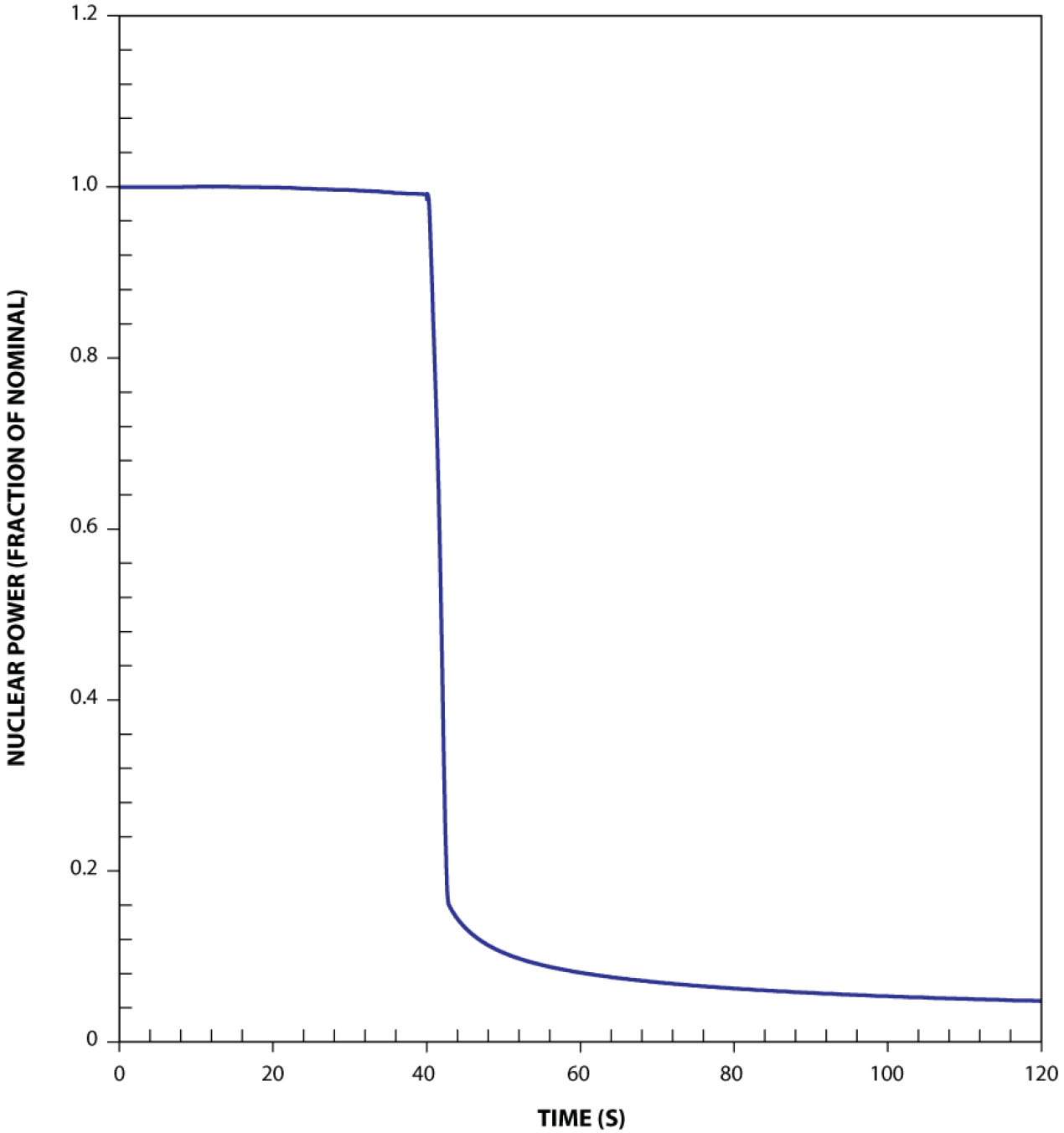
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-4 Feedwater Line Break RCS Overpressure Case Limiting Break Size = 0.21 ft^2 Steam Generator Mass vs. Time



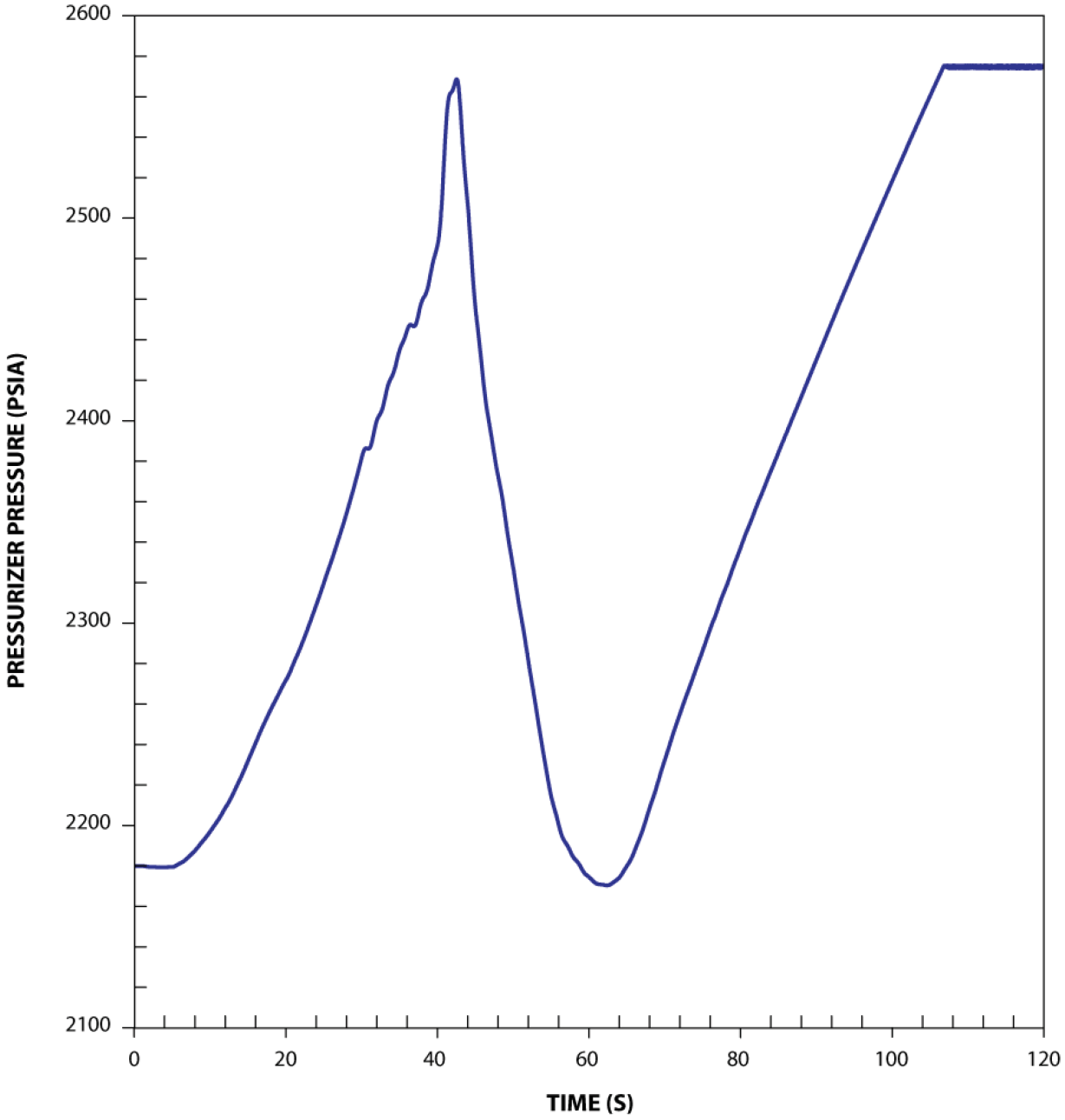
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-5 Feedwater Line Break RCS Overpressure Case Limiting Break Size = 0.21 ft^2 Steam Generator Pressure vs. Time



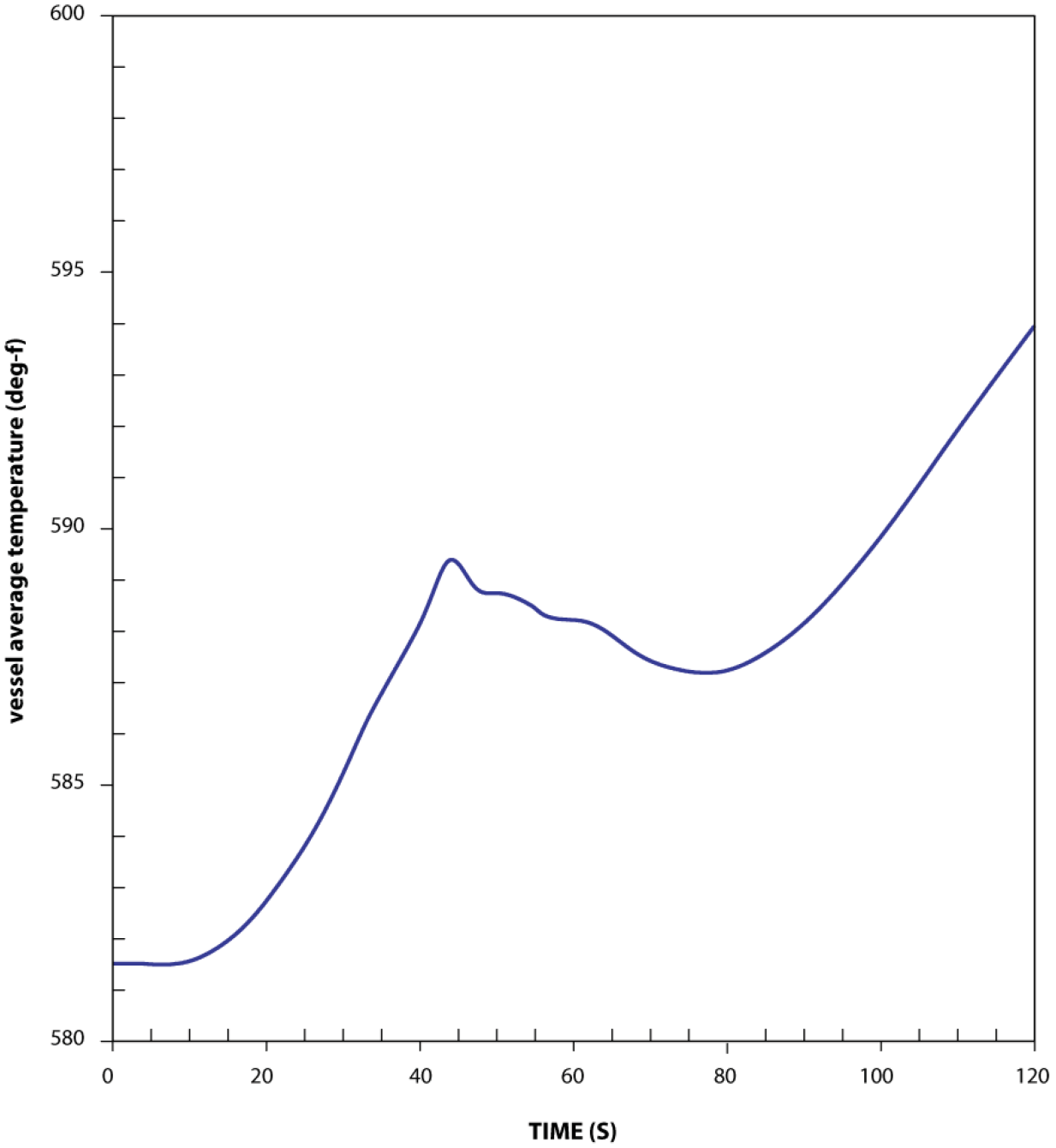
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-6 Feedwater Line Break RCS Overpressure Case Limiting Break Size = 0.21 ft^2 Break Flow Rate vs. Time



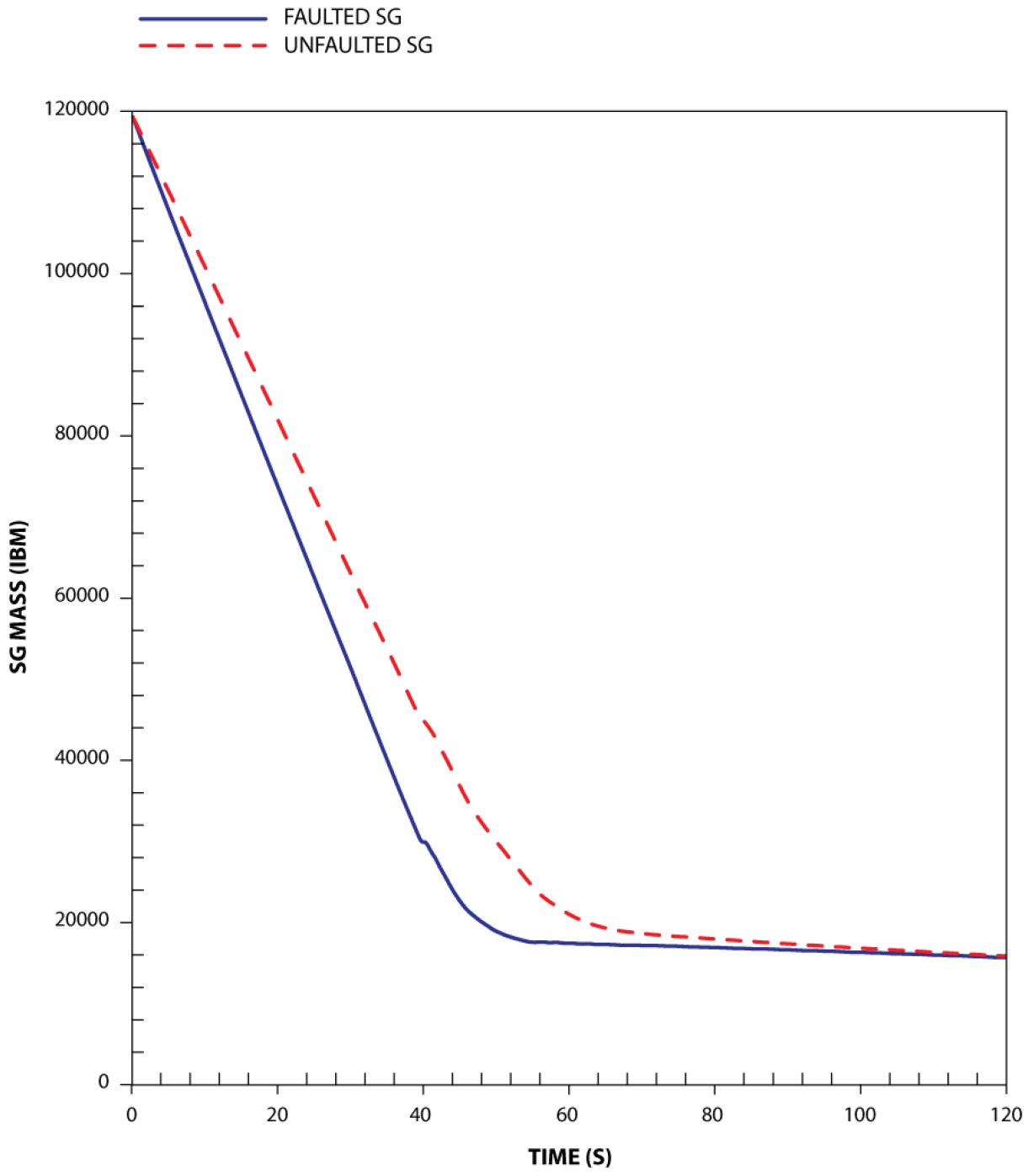
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-7 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Nuclear Power vs. Time



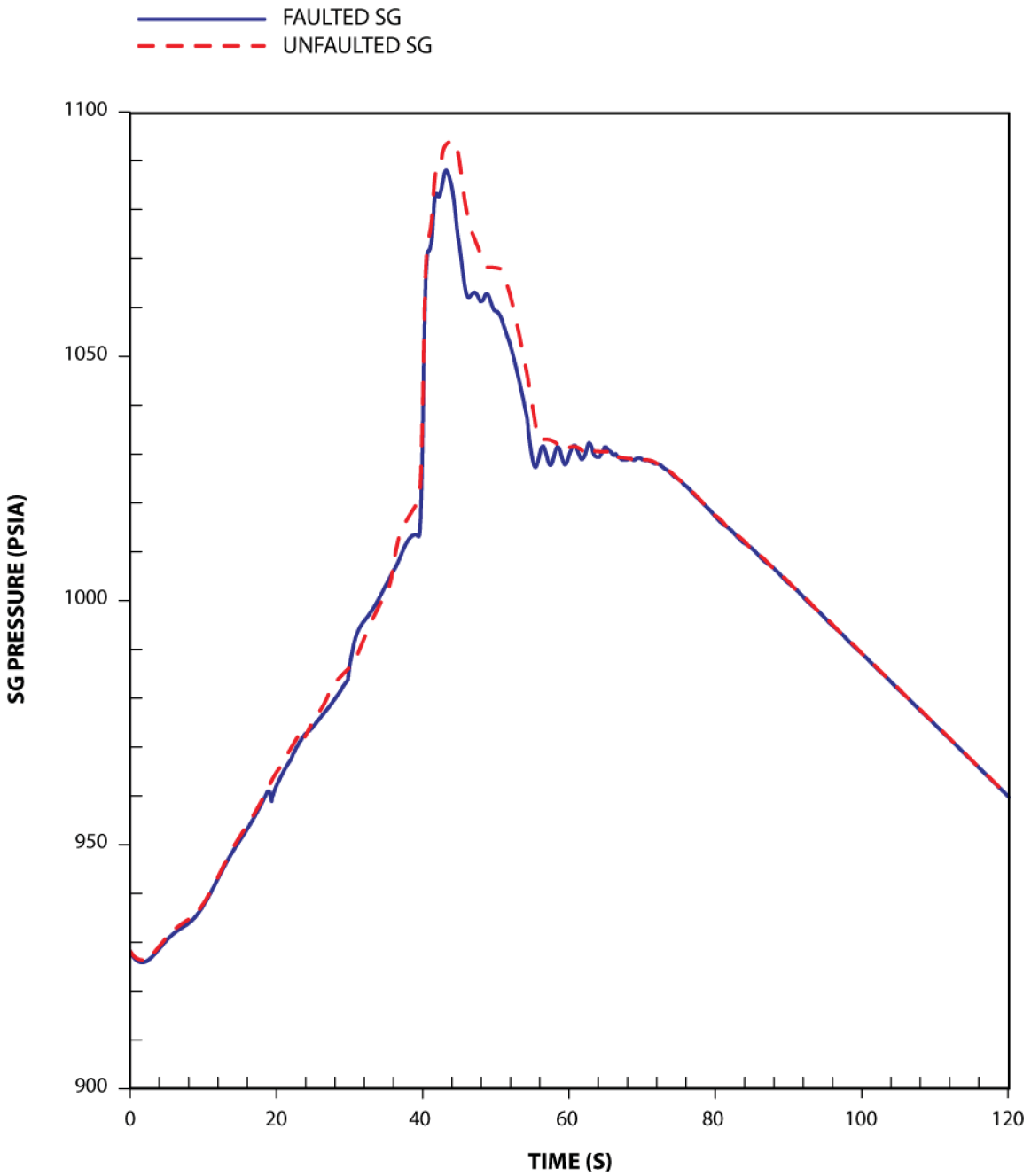
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-8 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Pressurizer Pressure vs. Time



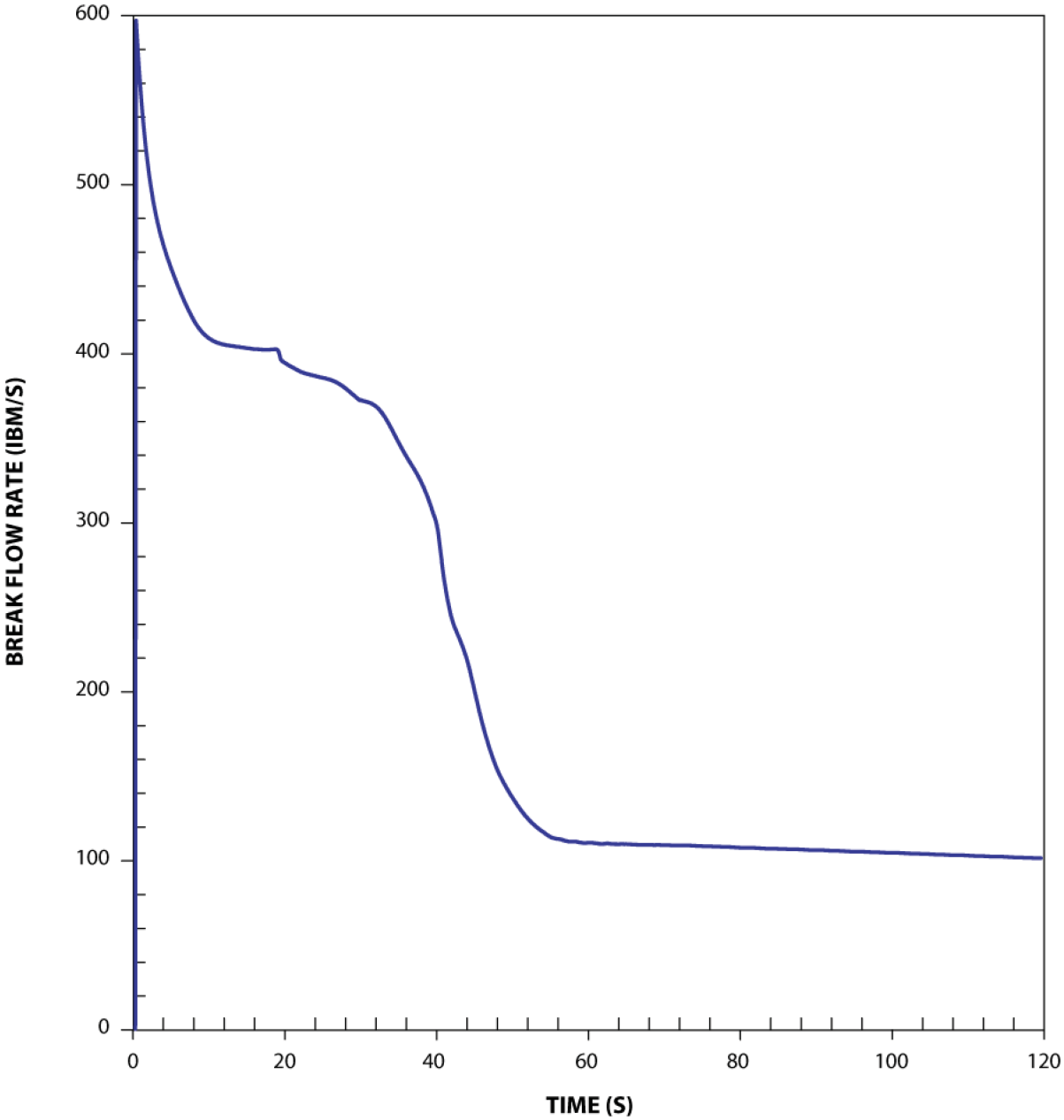
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-9 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Vessel Average Temperature vs. Time



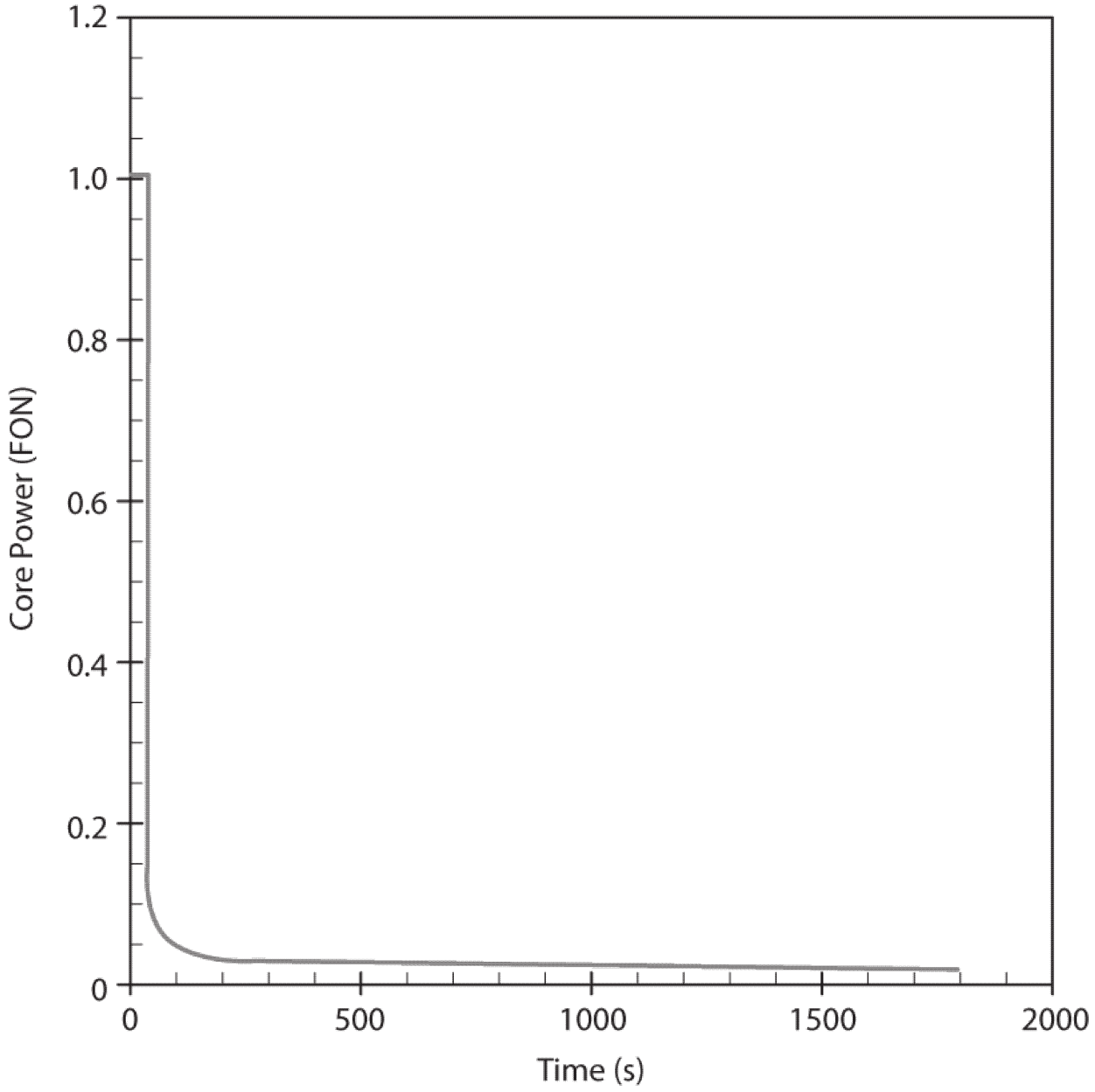
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-10 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Steam Generator Mass vs. Time



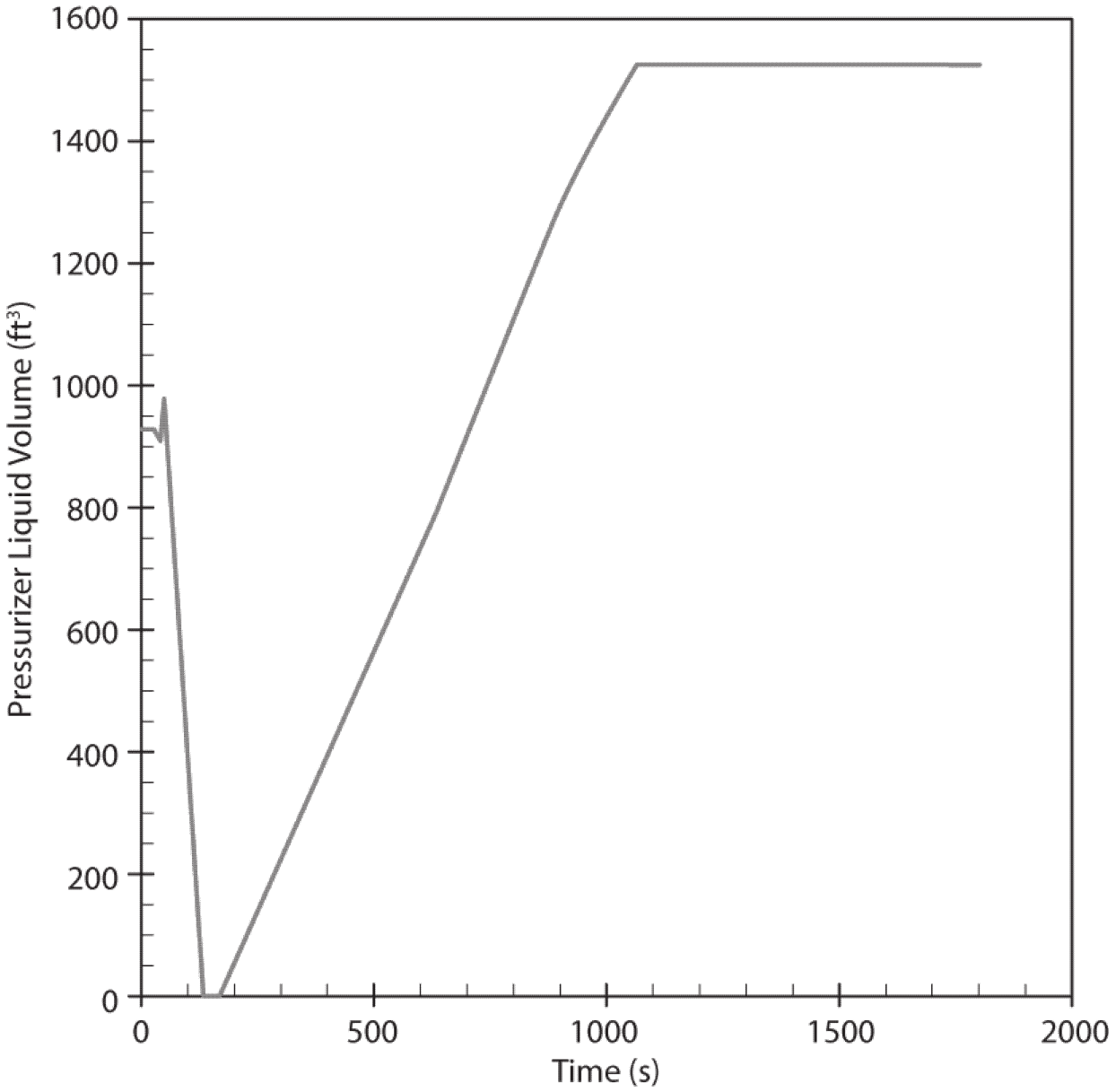
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-11 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Steam Generator Pressure vs. Time



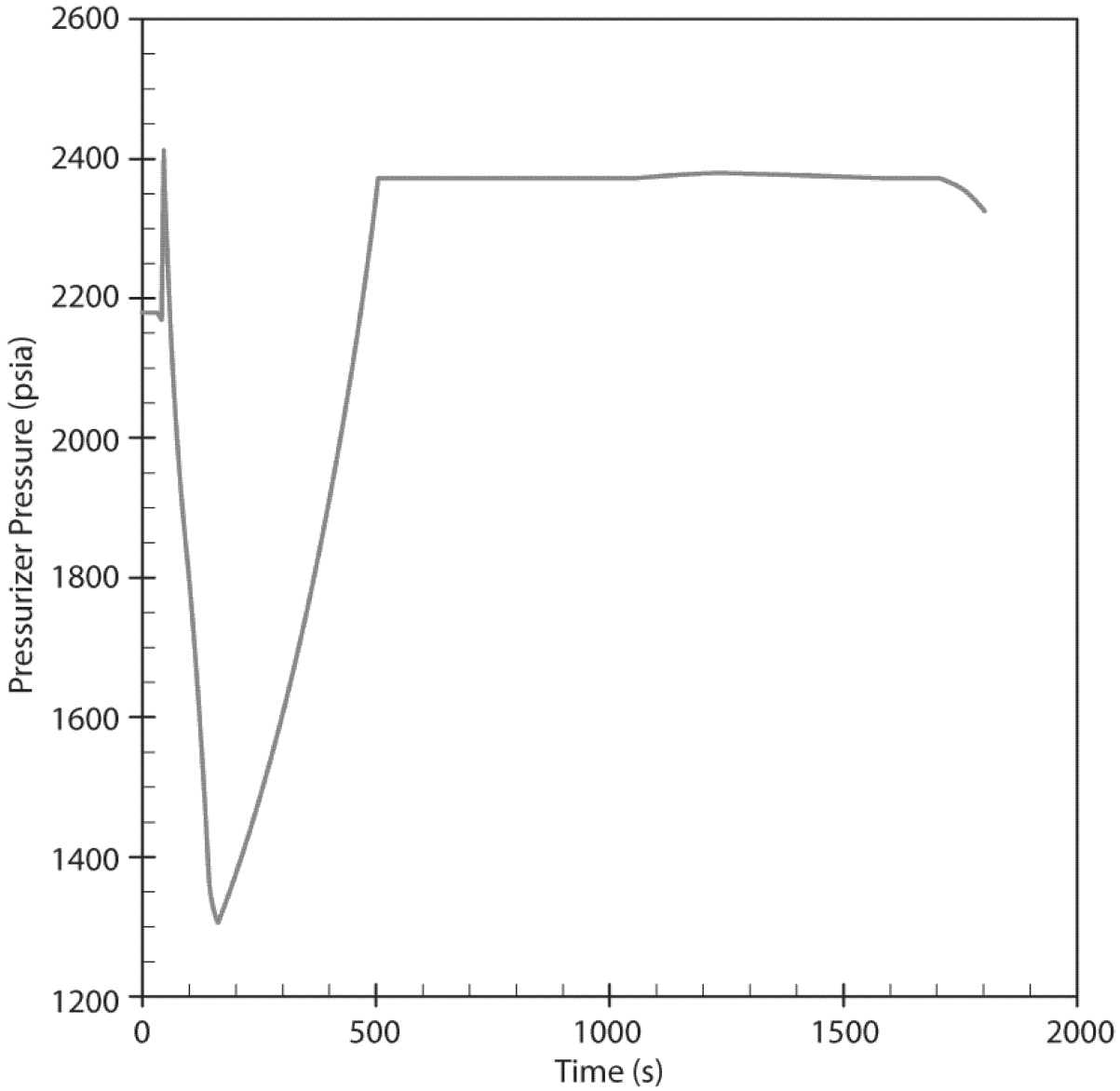
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-12 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Break Flow Rate vs. Time



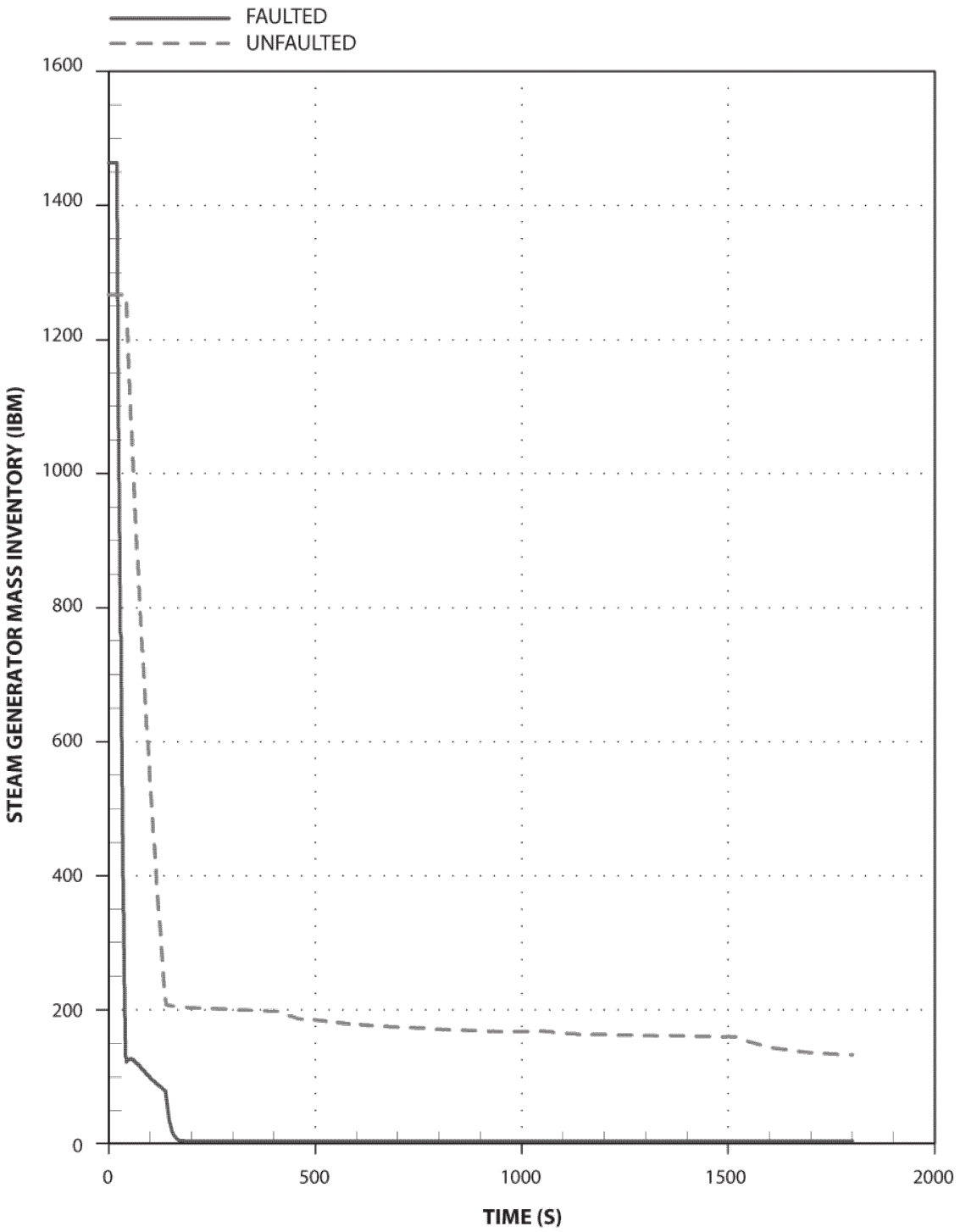
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-13 Feedwater Line Break (Subcooling Case) Nuclear Power vs. Time



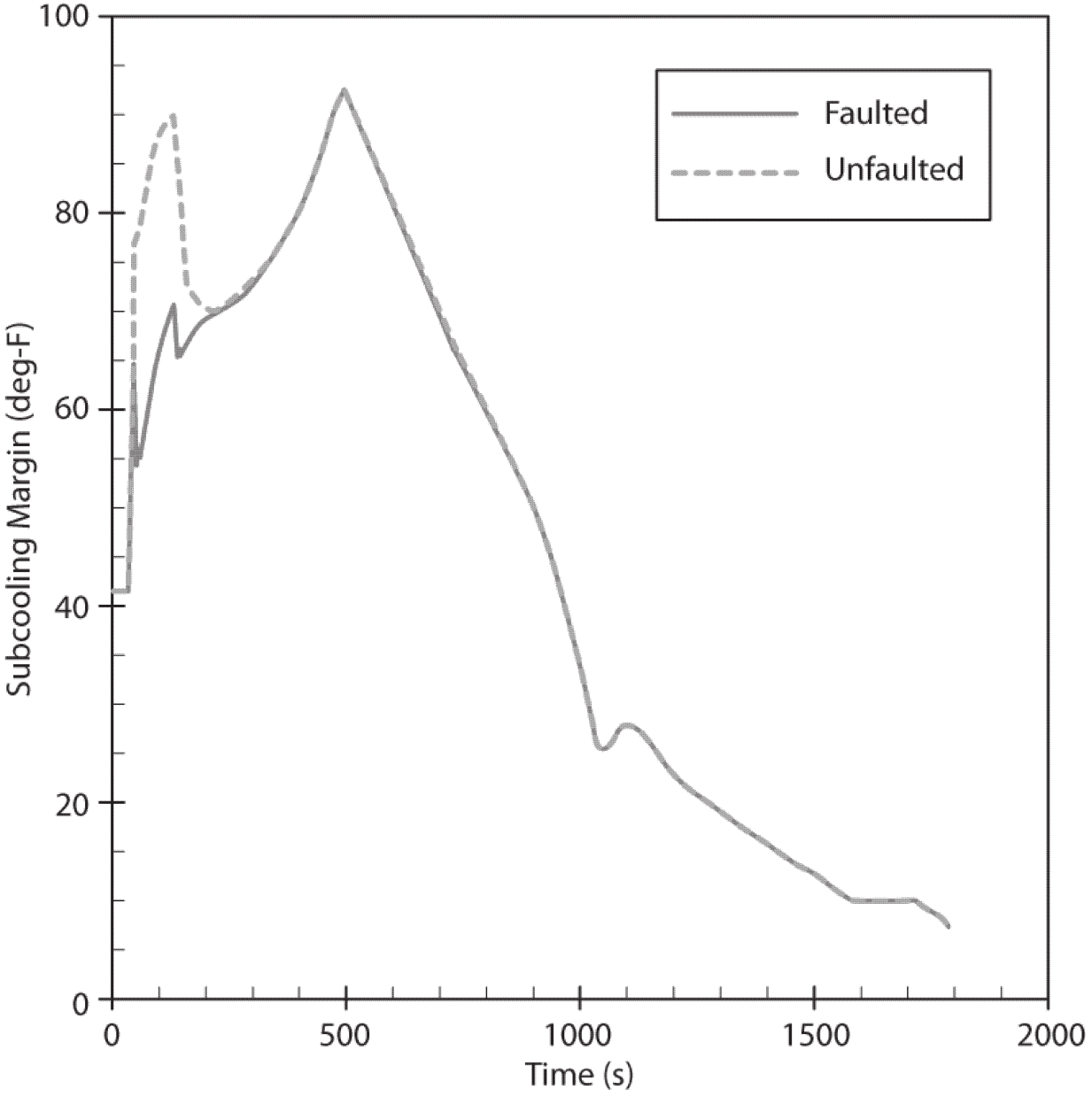
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-14 Feedwater Line Break (Subcooling Case) Pressurizer Liquid Volume vs. Time



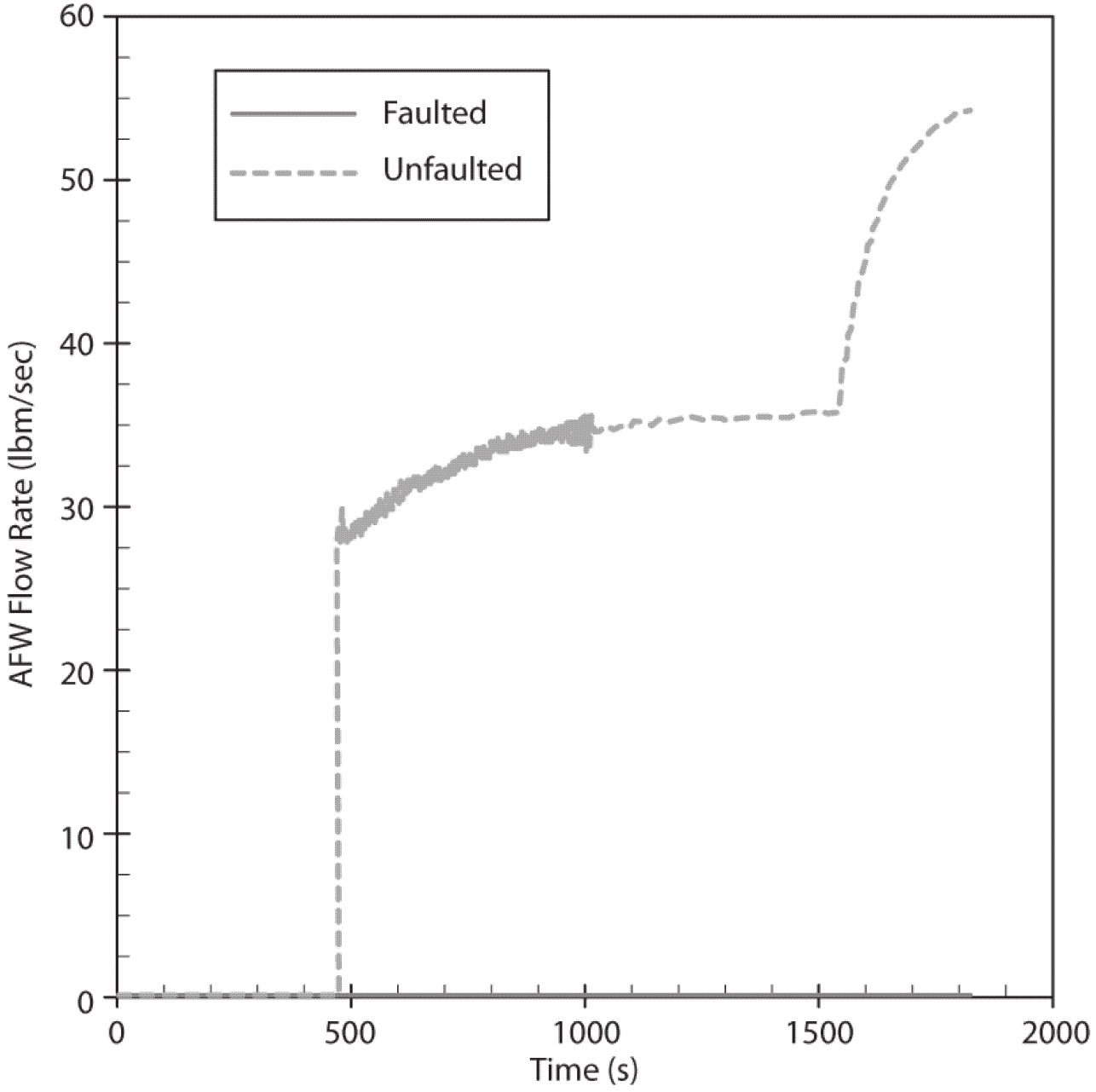
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-15 Feedwater Line Break (Subcooling Case) Pressurizer Pressure vs. Time



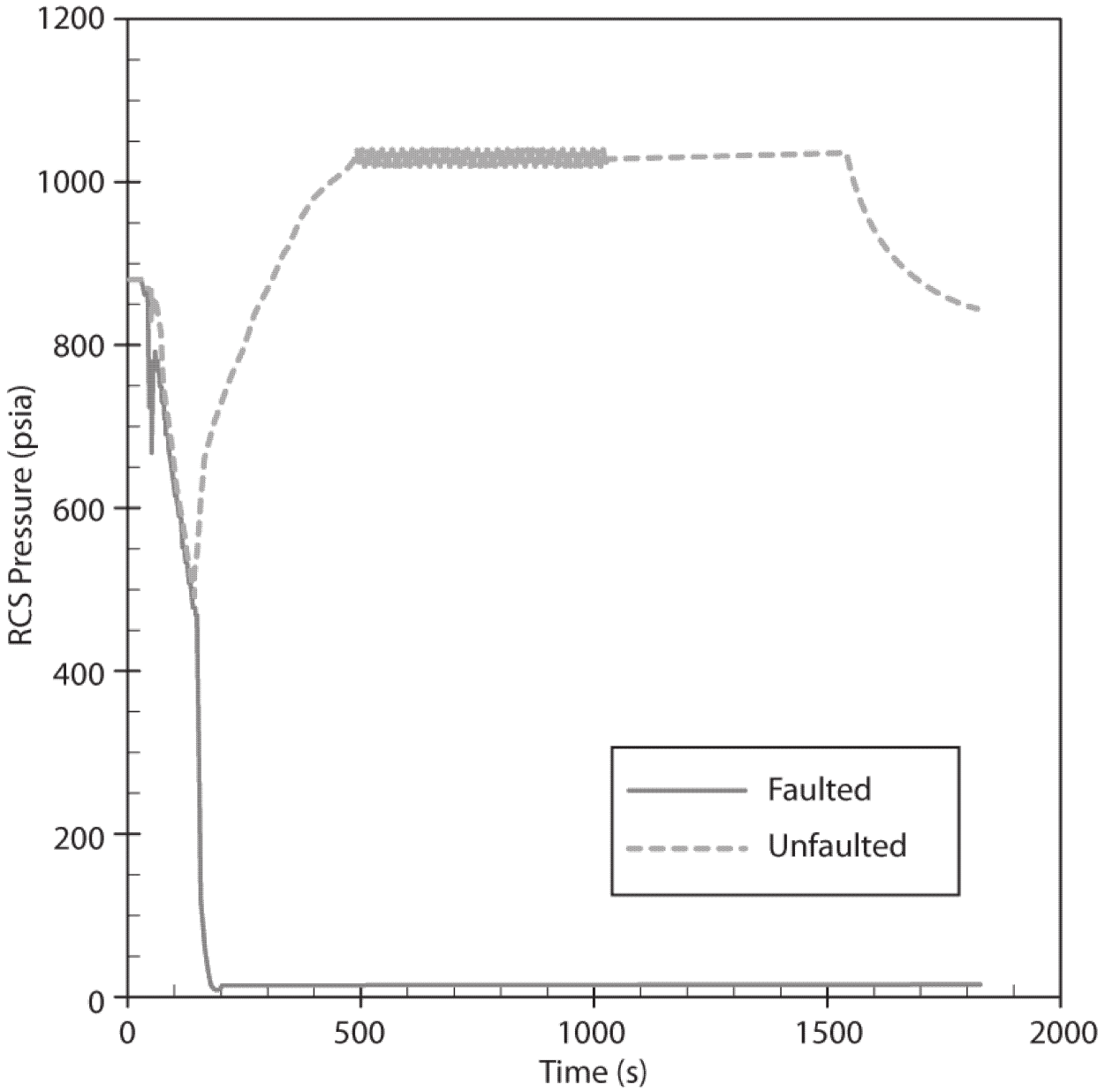
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-16 Feedwater Line Break (Subcooling Case) Steam Generator Mass vs. Time



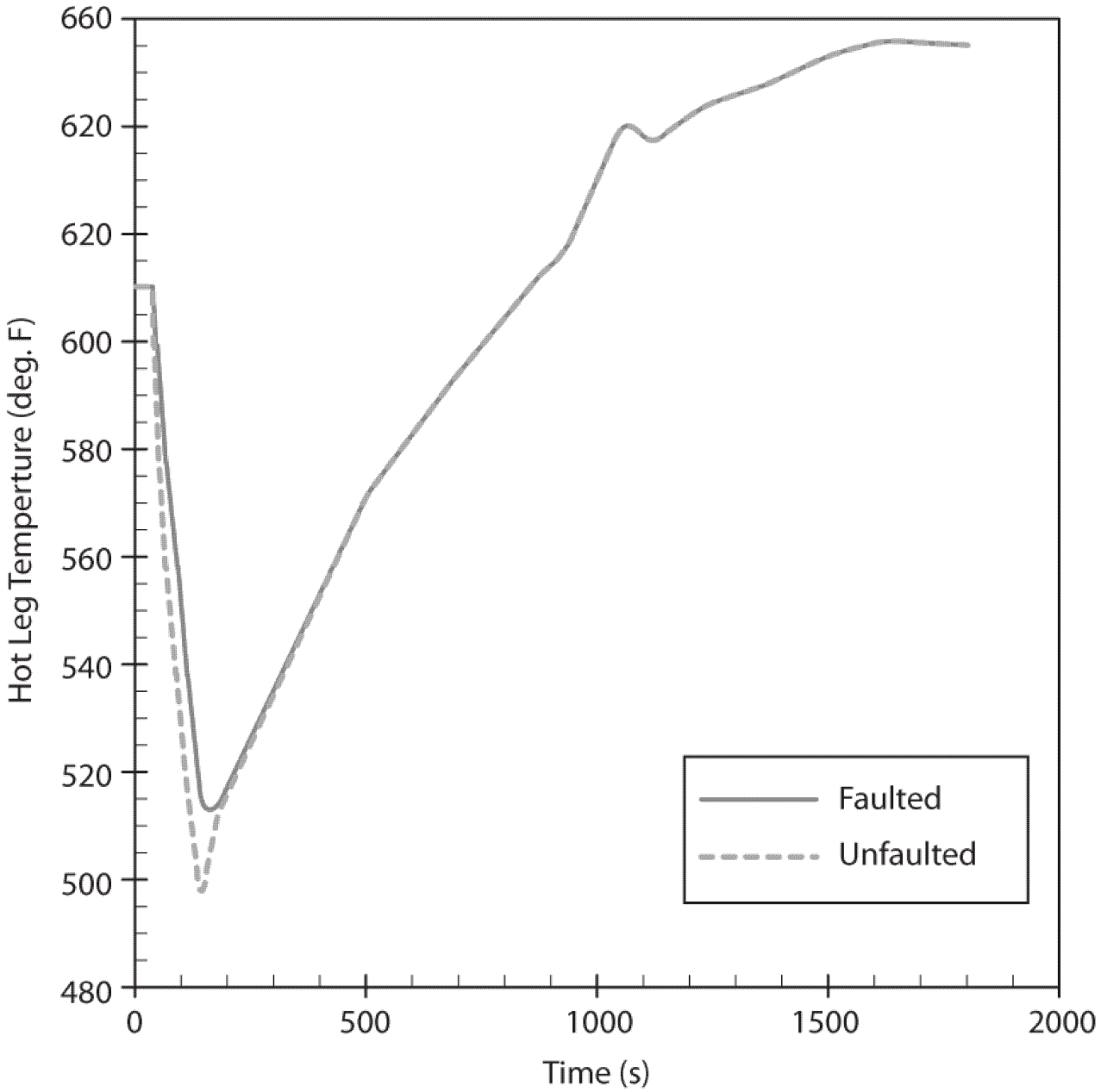
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-17 Feedwater Line Break (Subcooling Case) Subcooling Margin vs. Time



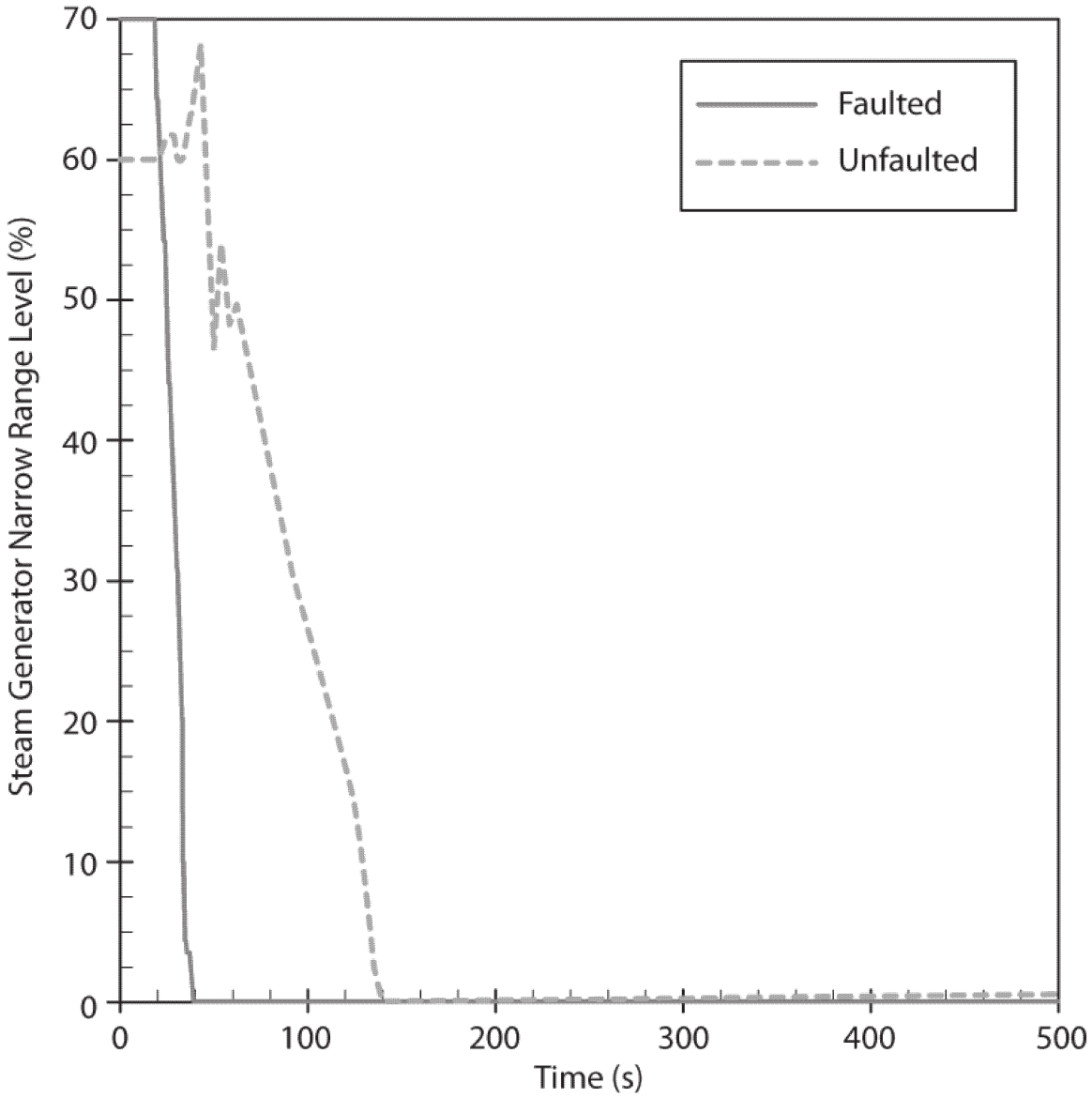
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-18 Feedwater Line Break (Subcooling Case) AFW Flow Rate vs. Time



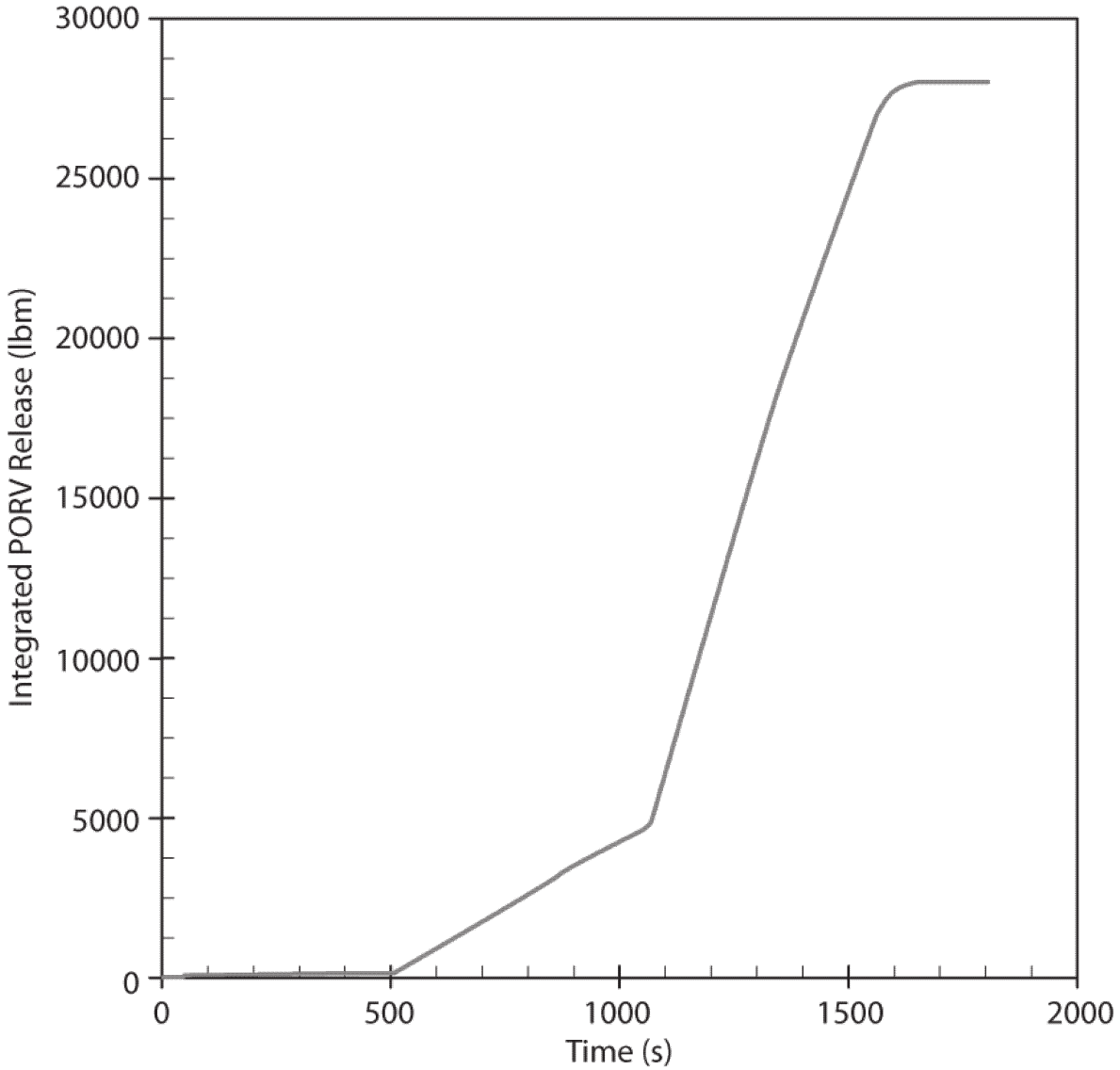
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-19 Feedwater Line Break (Subcooling Case) Steam Generator Pressure vs. Time



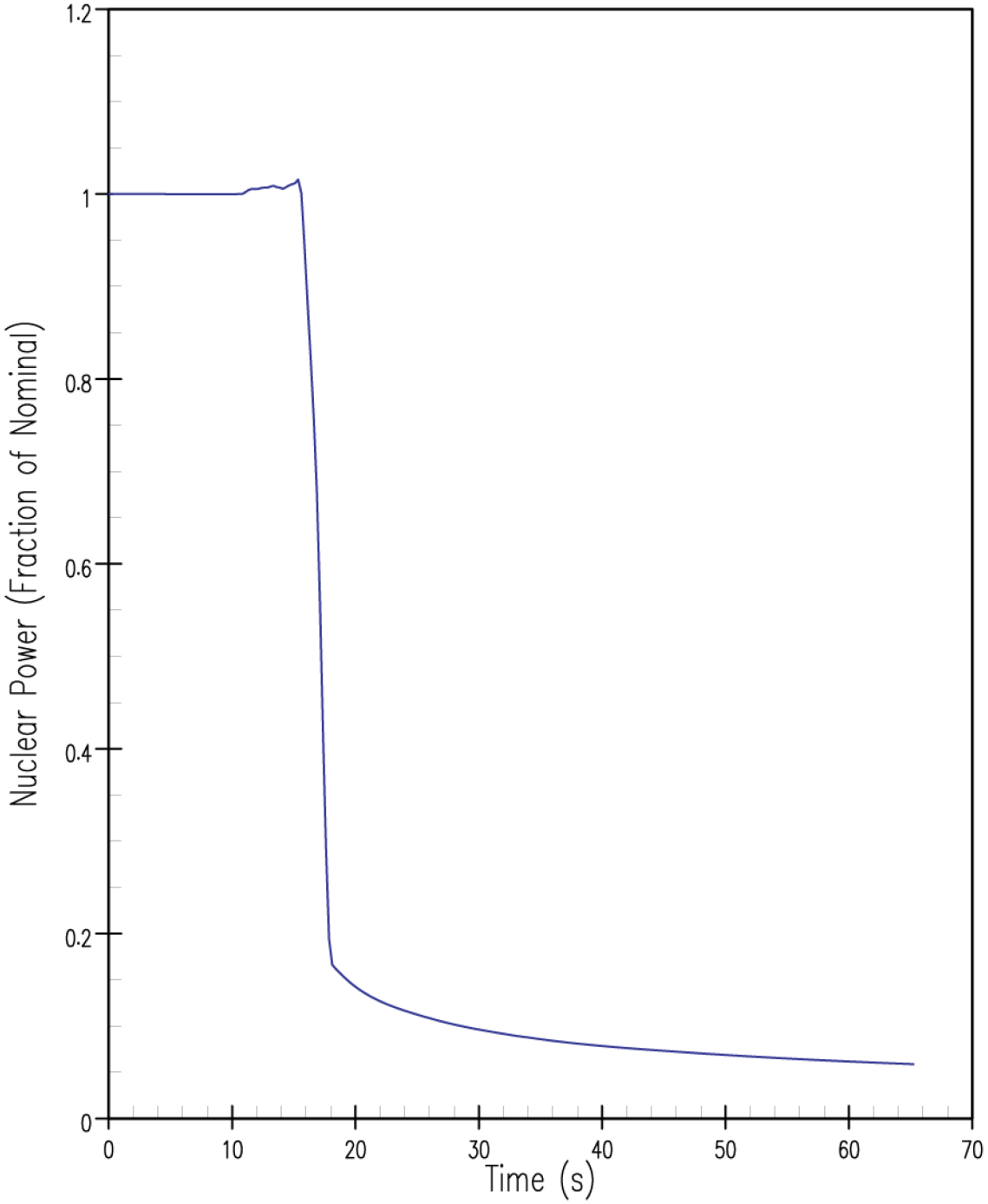
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-20 Feedwater Line Break (Subcooling Case) Hot Leg Temperature vs. Time



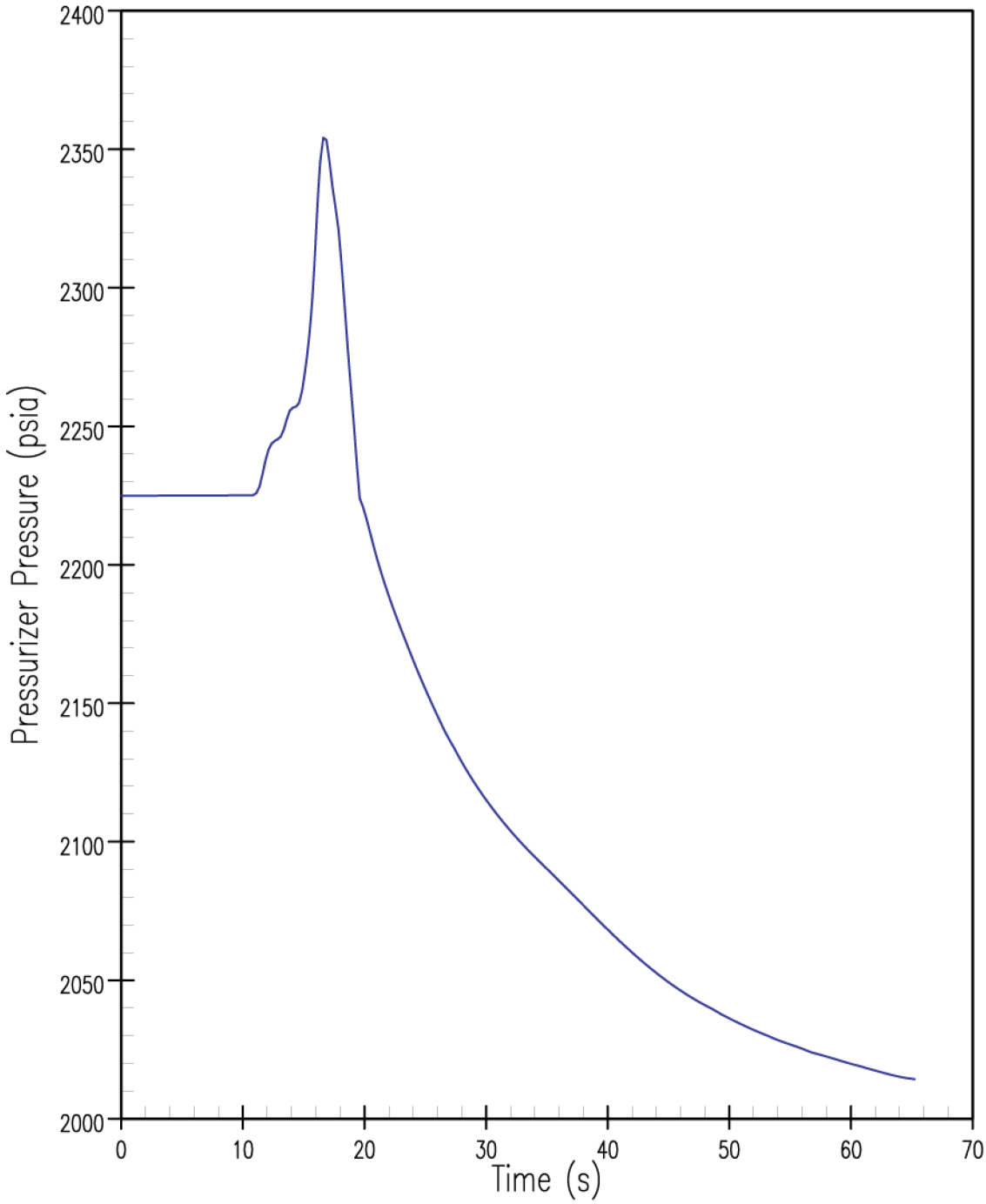
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-21 Feedwater Line Break (Subcooling Case) Steam Generator NR Level vs. Time



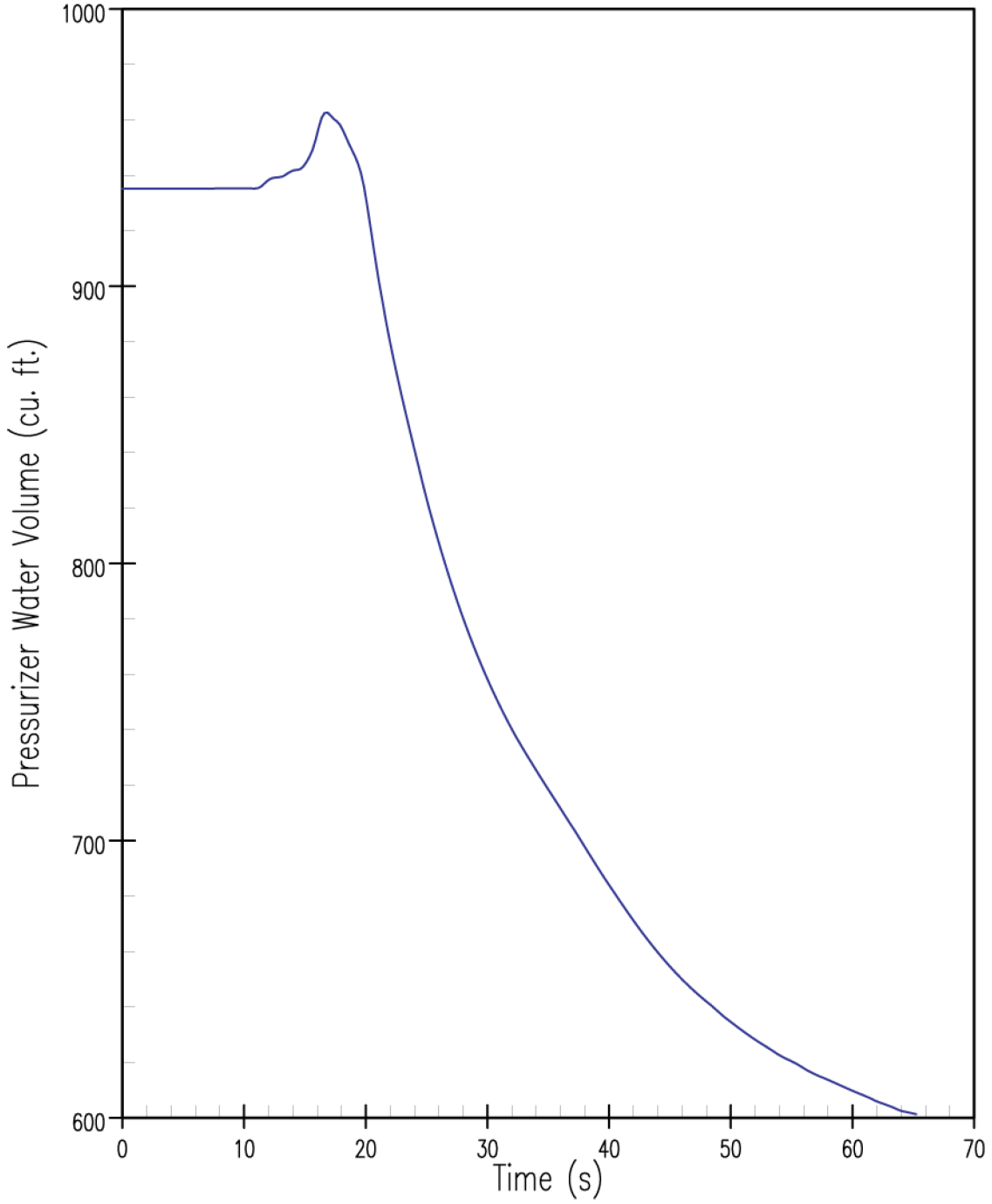
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.8-22 Feedwater Line Break (Subcooling Case) Integrated PORV Release vs. Time



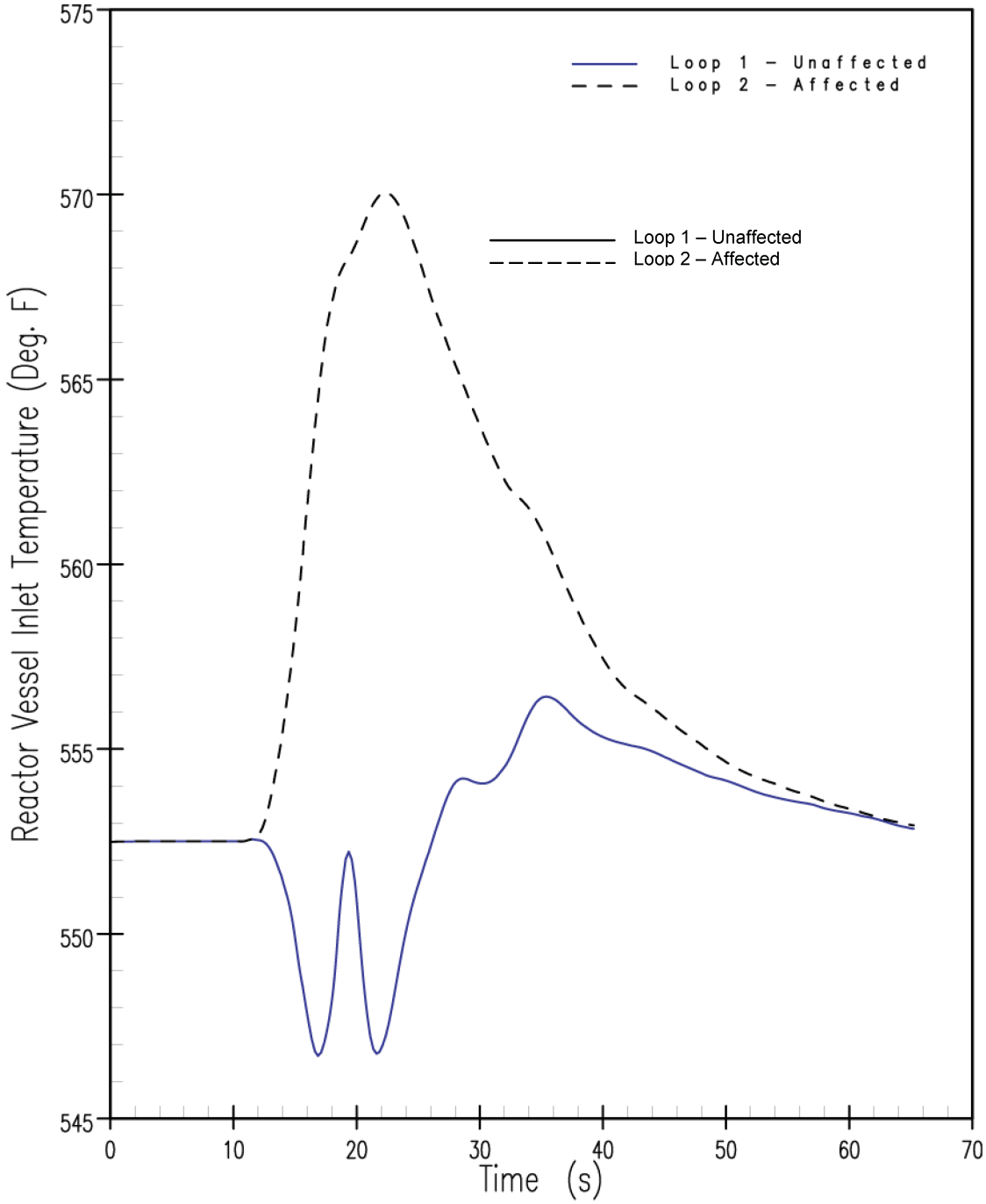
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-1 Asymmetric Steam Generator Transient (10% SGTP) Nuclear Power vs. Time



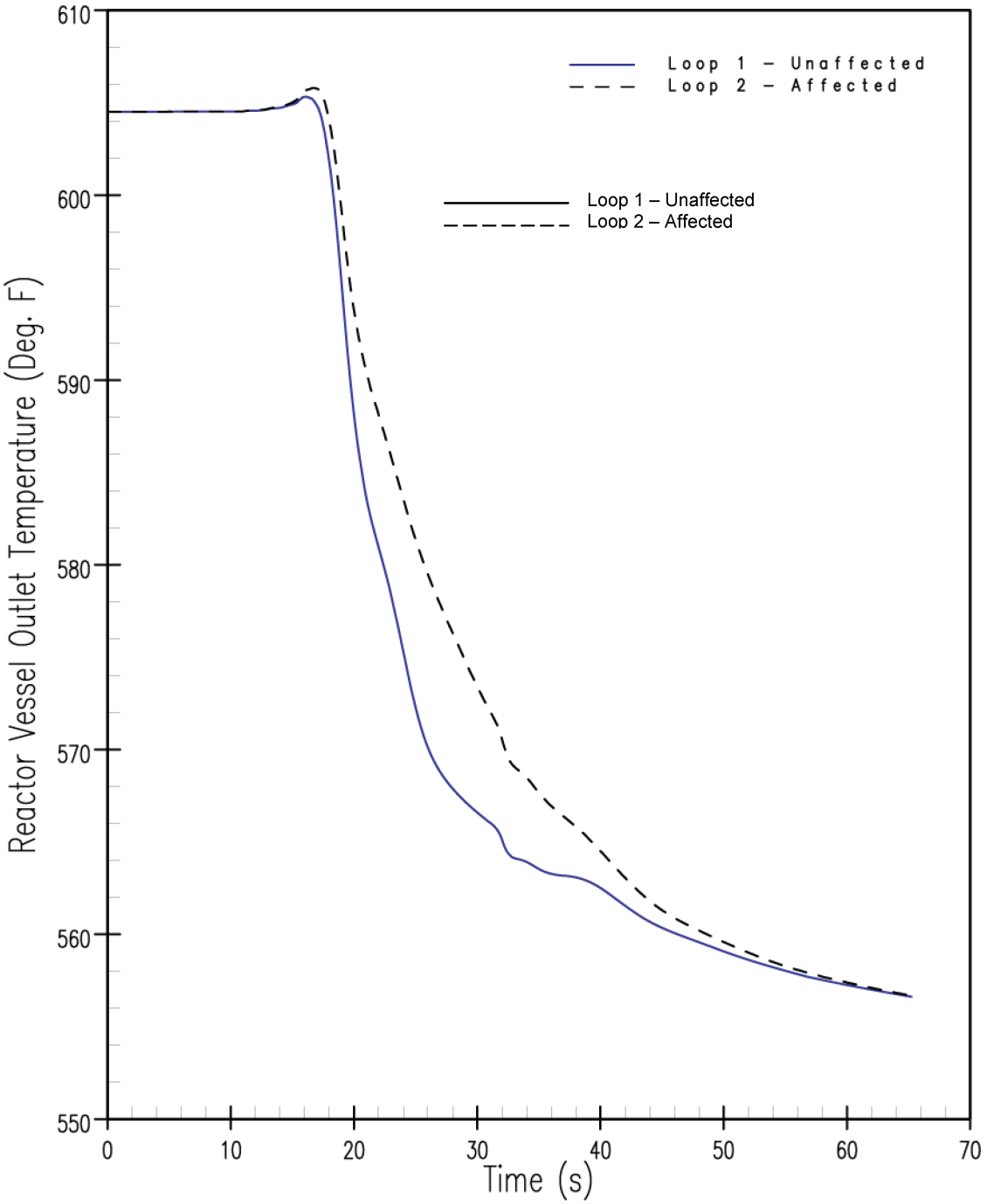
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-2 Asymmetric Steam Generator Transient (10% SGTP) RCS (Pressurizer) Pressure vs. Time



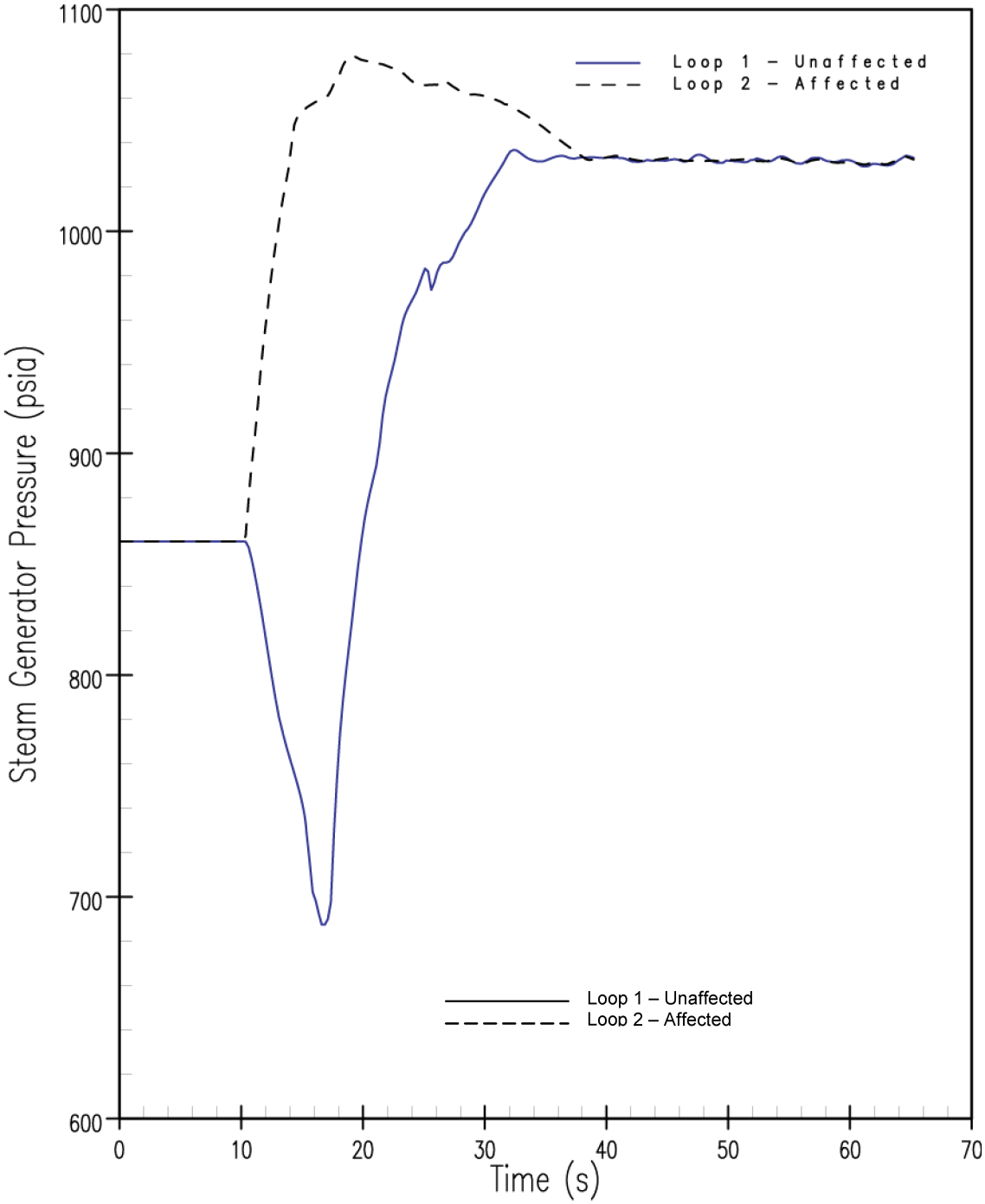
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-3 Asymmetric Steam Generator Transient (10% SGTP) Pressurizer Water Volume vs. Time



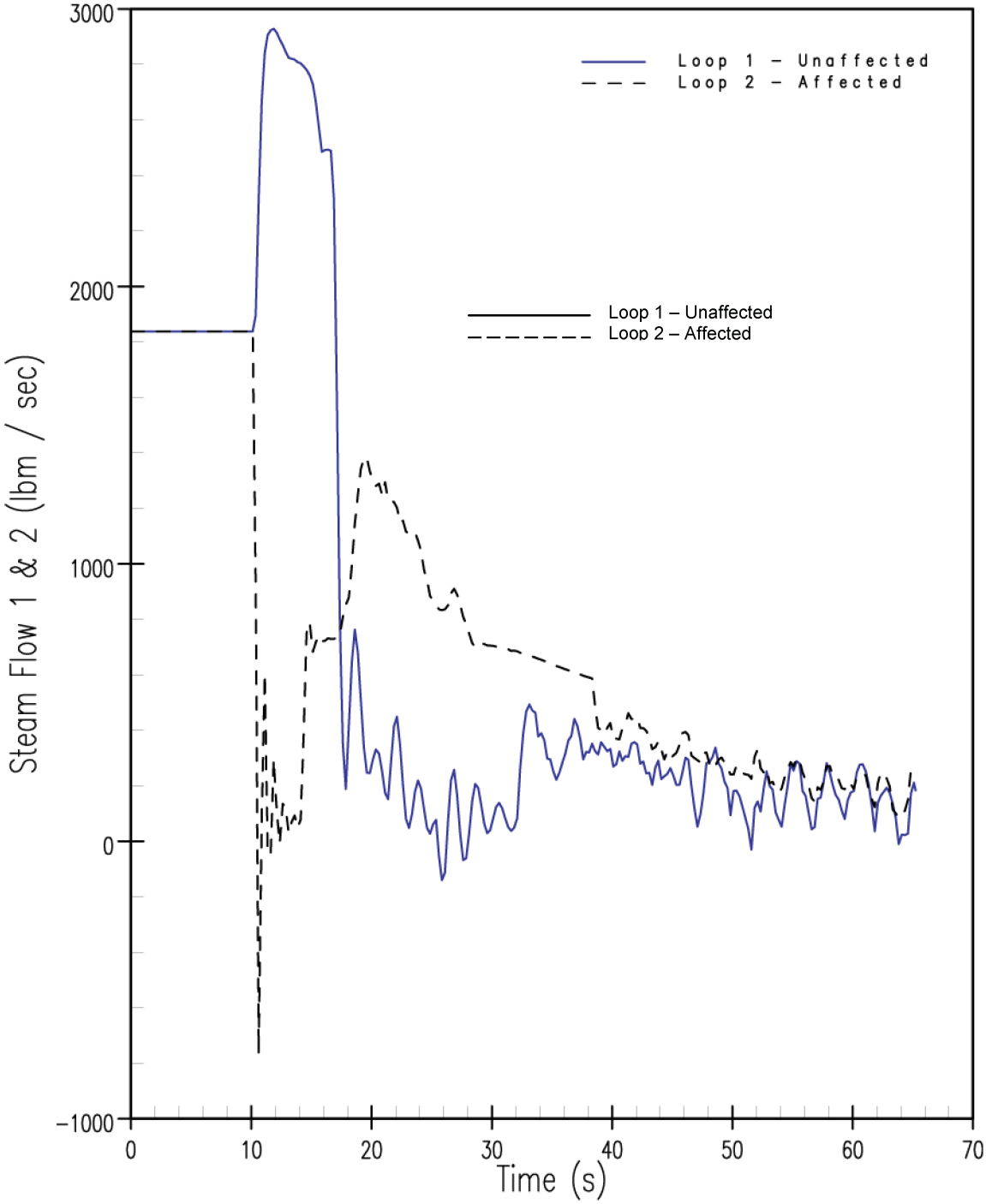
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-4 Asymmetric Steam Generator Transient (10% SGTP) Vessel Inlet Temperature vs. Time



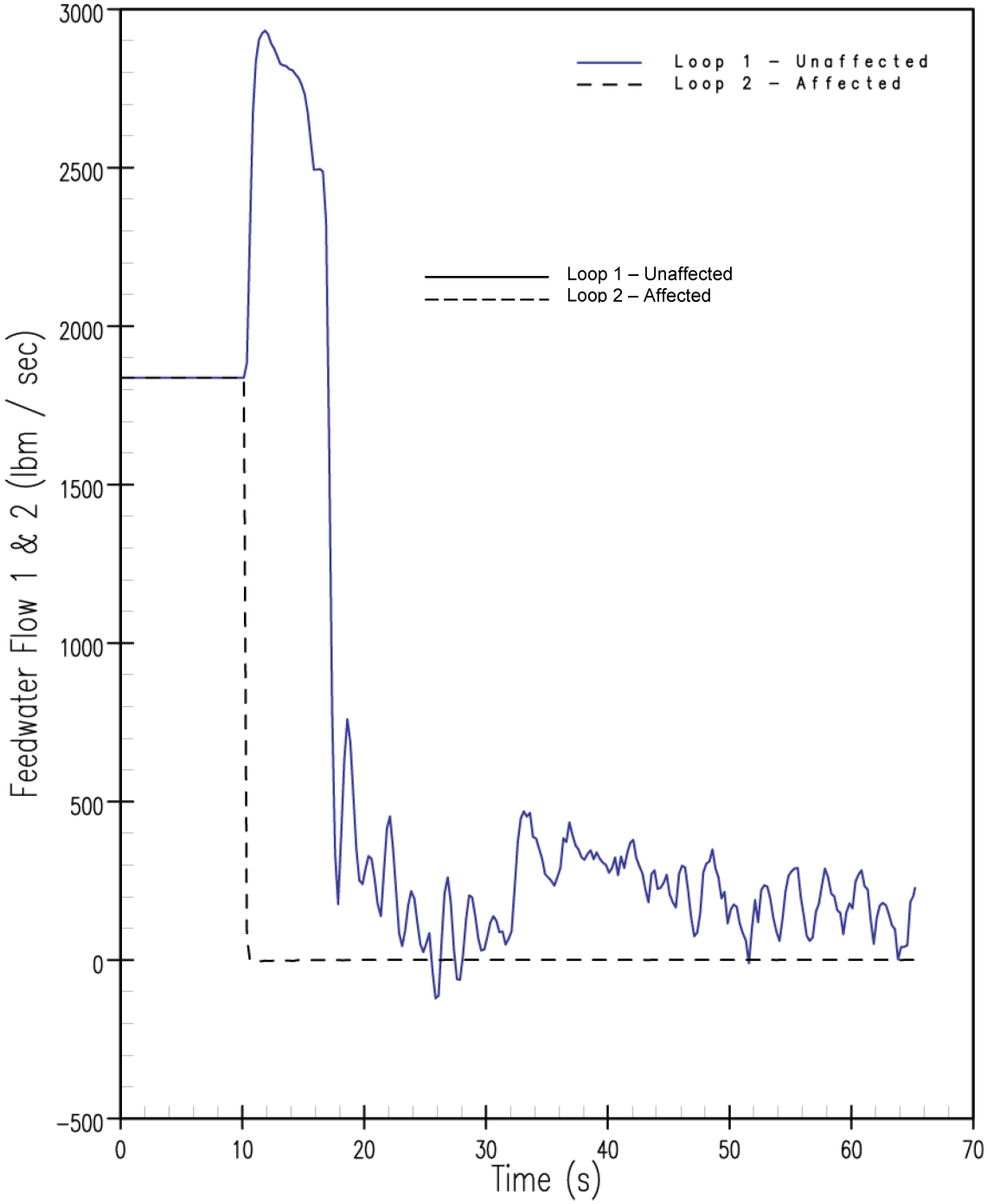
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-5 Asymmetric Steam Generator Transient (10% SGTP) Vessel Outlet Temperature vs. Time



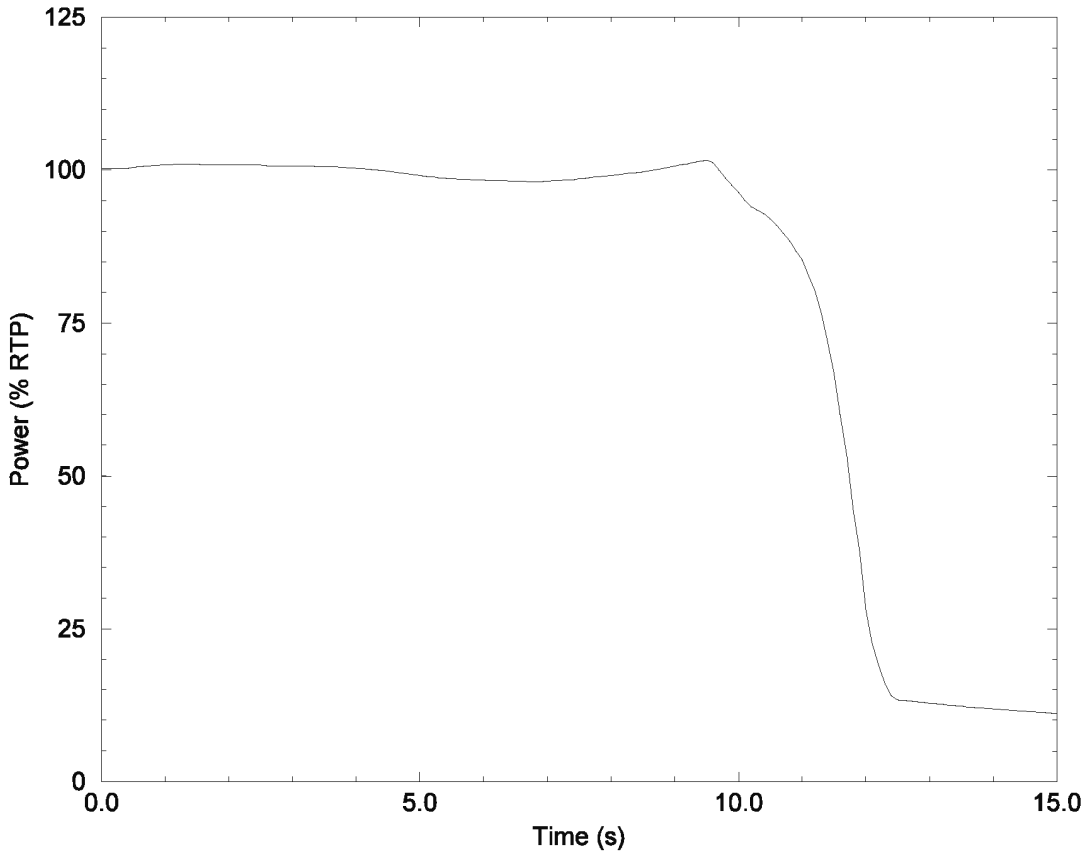
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-6 Asymmetric Steam Generator Transient (10% SGTP) Steam Generator Pressure vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-7 Asymmetric Steam Generator Transient (10% SGTP) Steam Flow vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.2.9-8 Asymmetric Steam Generator Transient (10% SGTP) Feedwater Flow vs. Time



EC287528

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ST. LUCIE PLANT UNIT 2

Figure 15.2.9-9
Asymmetric Steam Generator Transient
(AREVA, 0% SGTP):
Reactor Power vs. Time

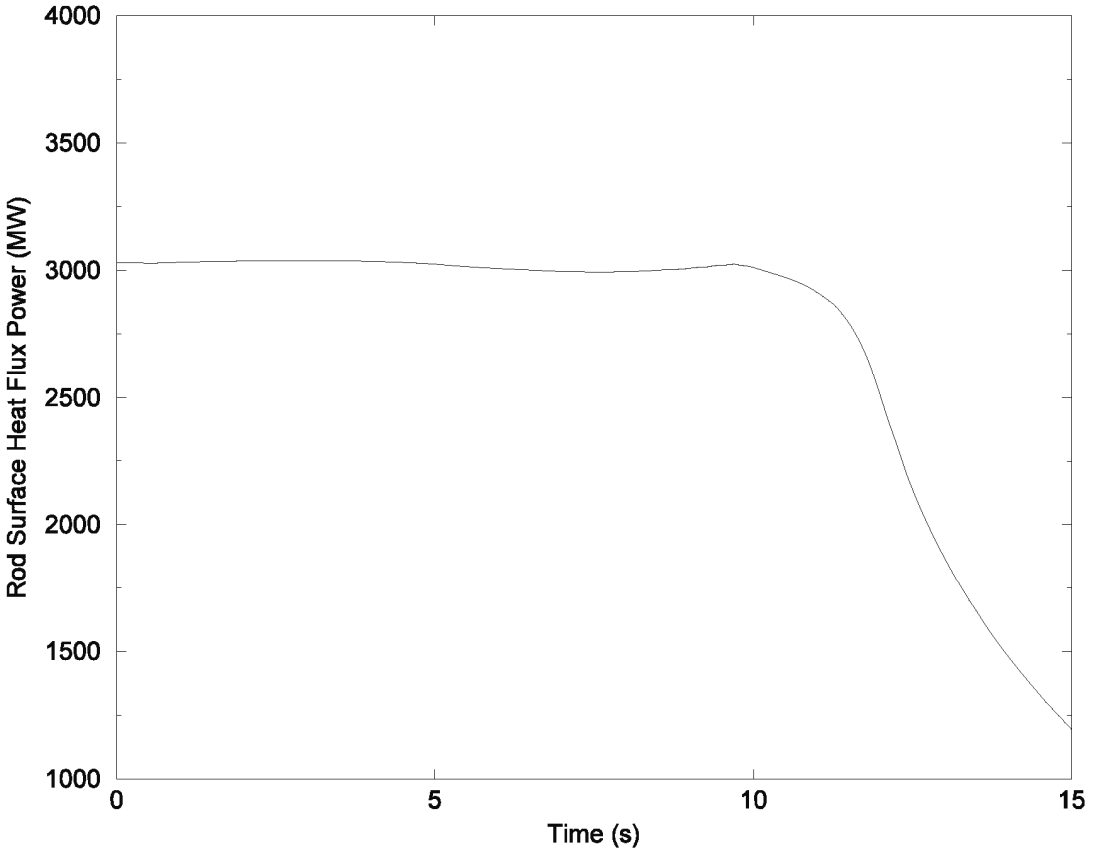

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Figure 15.2.9-10
Asymmetric Steam Generator Transient
(AREVA, 0% SGTP):
Total Core Heat Flux Power vs. Time

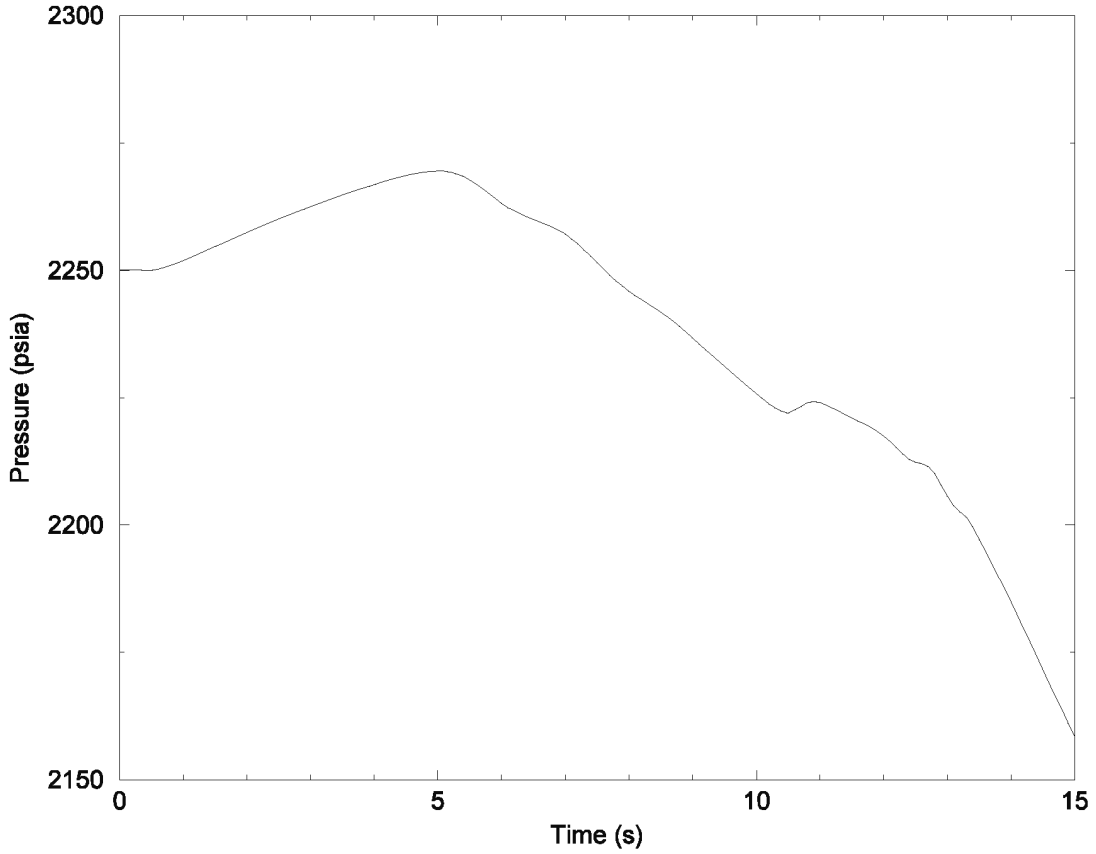

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Figure 15.2.9-11
Asymmetric Steam Generator Transient
(AREVA, 0% SGTP):
Pressurizer Pressure vs. Time

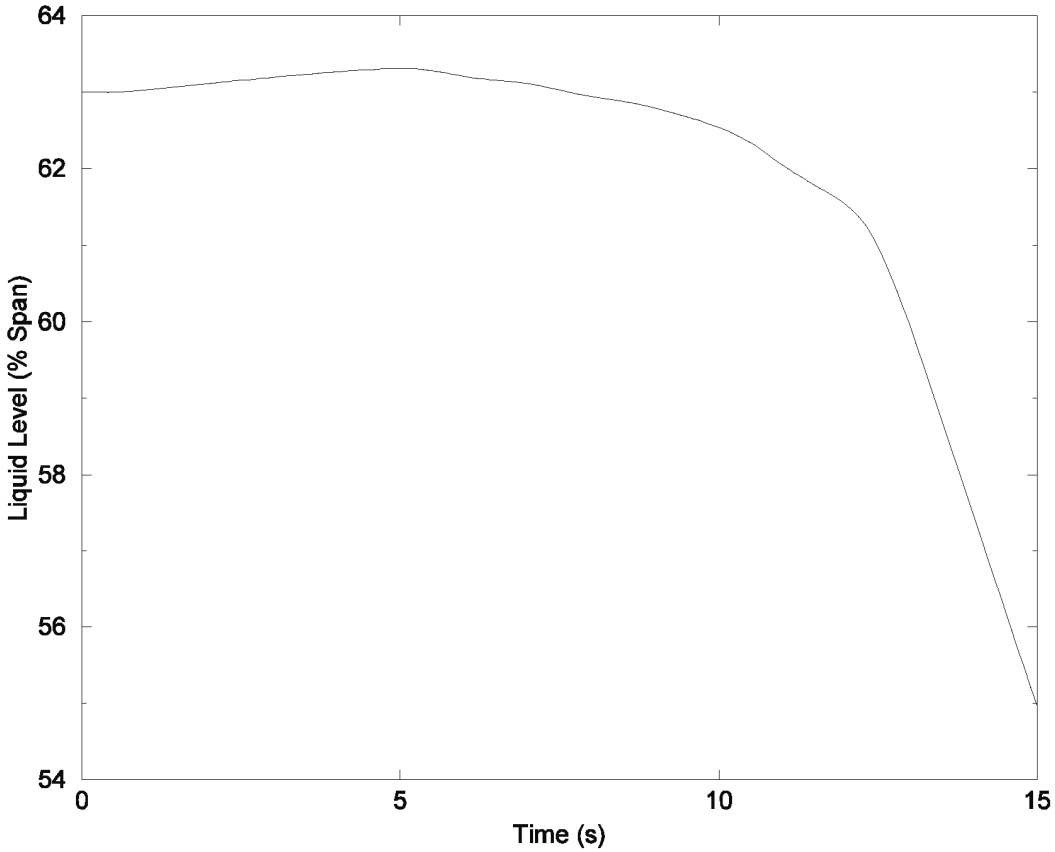

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Figure 15.2.9-12
Asymmetric Steam Generator Transient
(AREVA, 0% SGTP):
Pressurizer Liquid Level vs. Time

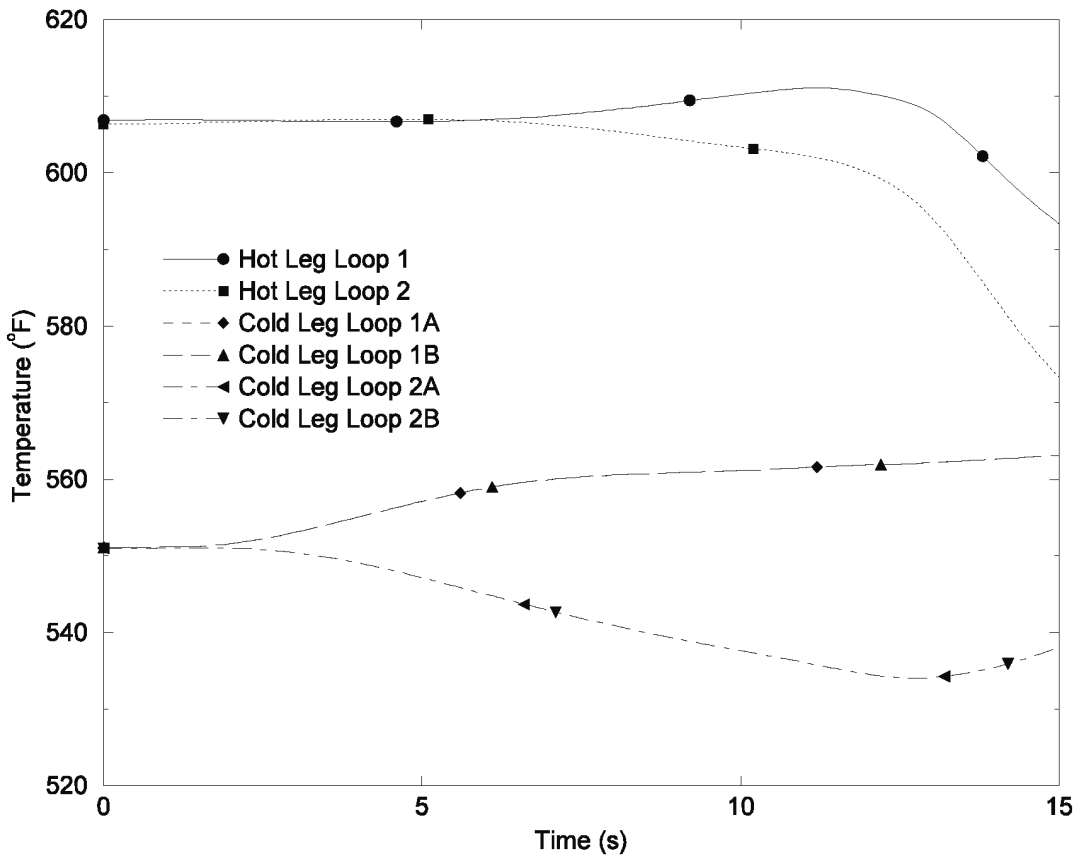

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Figure 15.2.9-13
Asymmetric Steam Generator Transient
(AREVA, 0% SGTP):
RCS Loop Temperatures vs. Time

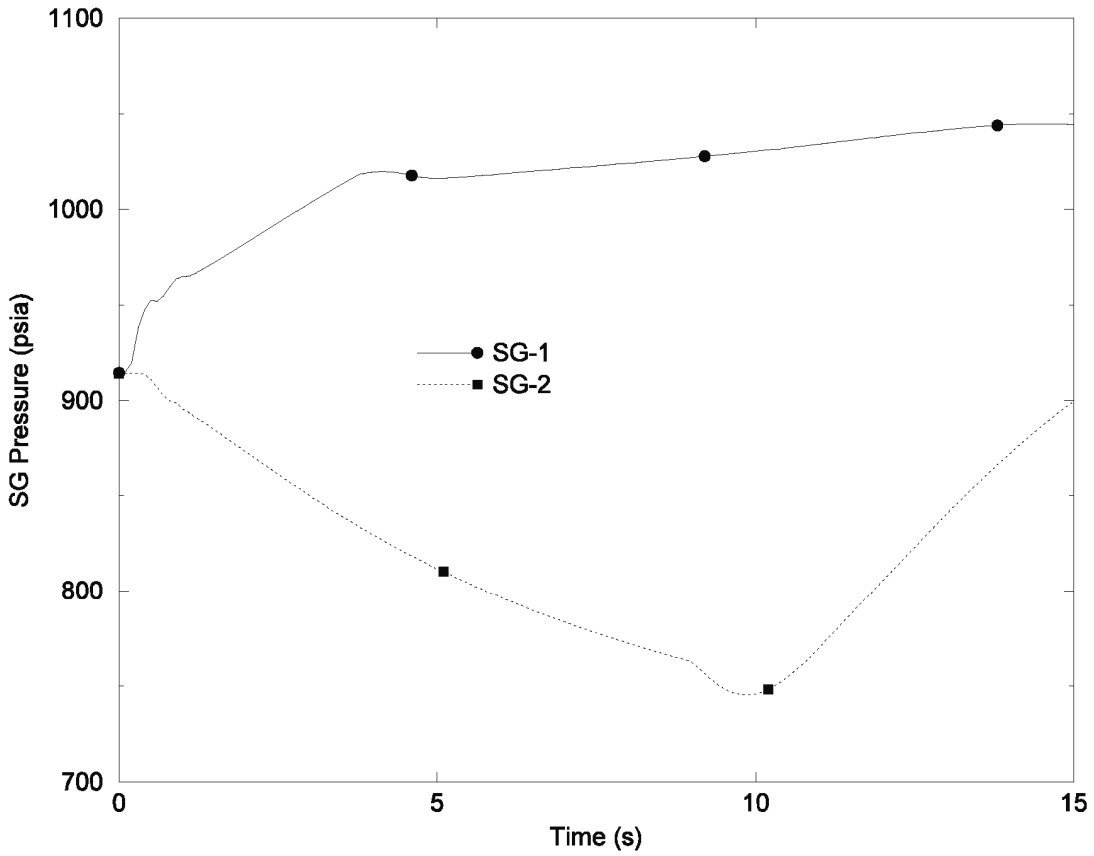

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Figure 15.2.9-14
Asymmetric Steam Generator Transient
(AREVA, 0% SGTP):
Steam Generator Pressures vs. Time

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

A number of faults are postulated which could result in a decrease in reactor coolant system (RCS) flow rate. These events are discussed in this section. Detailed analyses are presented for the most limiting of these events.

Discussions of the following flow decrease events are presented in this section:

a. Partial loss of forced reactor coolant flow (Section 15.3.1)

b. Complete loss of forced reactor coolant flow (Section 15.3.2)

c. Reactor coolant pump shaft seizure (locked rotor) (Section 15.3.3)

d. Reactor coolant pump shaft break (Section 15.3.4)

Item (a) above is considered to be an ANS Condition II event, item (b) an ANS Condition III event, and items (c) and (d) ANS Condition IV events. Section 15.0.6 contains a discussion of ANS classifications.

15.3.1 PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW

Partial loss of forced reactor flow is caused by loss of electrical power to one or more of the reactor coolant pumps (RCPs). This is caused by the opening of a reactor coolant pump power supply circuit breaker or the loss of a 6.9 kV bus. Even with the change to AREVA fuel, the core and system performance following a partial loss of forced reactor coolant flow would be no more adverse than those following a complete loss of forced reactor coolant flow discussed in Section 15.3.2. Therefore, an explicit analysis of the Partial Loss of Flow event is not presented herein. EC287528

15.3.2 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

15.3.2.1 Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all RCPs. If the reactor is at power at the time of the accident, the immediate effect of loss-of-coolant flow is a rapid increase in the coolant temperature. This increase could result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor were not tripped promptly.

Normal power for the RCPs is supplied through buses from a transformer connected to the generator and the offsite power system. Two diametrically opposed pumps are on a separate bus. When a generator trip occurs, the buses continue to be supplied from external power lines and the pumps continue to supply coolant flow to the core.

The following signal provides the necessary protection against a complete loss-of-flow accident:

- Low reactor coolant loop flow reactor trip

The reactor trip on low primary coolant flow is provided to protect against loss-of-flow conditions that affect one or both reactor coolant loops.

This event is conservatively analyzed to the following acceptance criteria:

- Pressure in the RCS and MSS should be maintained below 110 percent of the design values.
- Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the limit value.
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

15.3.2.2 Method of Analysis

The complete loss-of-flow transient is analyzed as a loss of four RCPs with both loops in operation. The event is analyzed to show that the integrity of the core is maintained as the DNBR remains above the safety analysis limit value. The loss-of-flow events do result in an increase in RCS and MSS pressures, but these pressure increases are generally not severe enough to challenge the integrity of the RCS and MSS. Since the maximum RCS and MSS pressures do not exceed 110 percent of their respective design pressures for the loss-of-condenser vacuum event, it is concluded that the maximum RCS and MSS pressures will also remain below 110 percent of their respective design pressures for the loss-of-flow events.

The limiting case analyzed is a complete loss-of-flow transient due to a loss of power to four pumps.

The transient is analyzed with two computer codes. First, the RETRAN computer code (References 15.3-1 and 15.3-2) is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE computer code (see Section 15.0.14.5) is then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

This event is analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 15.3-3). Initial reactor power, pressurizer pressure and RCS temperature are assumed to be at their nominal values. The RCS flow is assumed to be the minimum measured flow. A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive MTC limit for full-power operation. These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached.

A limiting DNB axial power shape is assumed in VIPRE for the calculation of DNBR. This shape provides the most limiting minimum DNBR for the loss-of-flow events.

A conservatively low trip worth is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time.

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity

equation, a pump momentum balance, and the pump characteristics. Also, it is based on conservative estimates of system pressure losses.

A maximum, uniform, steam generator tube plugging (SGTP) level of 10 percent was assumed in the RETRAN analysis. Reactor coolant system loop flow asymmetry due to a loop-to-loop SGTP imbalance does not need to be considered for transients in which all reactor coolant pumps experience a coastdown.

AREVA Analysis

The primary concern with this event is the challenge to the DNB SAFDL. The reduction in primary system flow and the associated increase in core coolant temperatures result in reduced margin to DNB. The increasing primary system coolant temperatures also result in expansion of the primary coolant volume, causing an in-surge into the pressurizer and an increase in the pressure of the primary system. However, the pressure increase is small, and the pressure limits are not challenged by this event.

For the fuel transition, detailed analyses were performed with the approved non-LOCA methodology (Reference 15.3-8). For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.3-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.3-10).

A single case was analyzed at BOC full-power initial conditions, TS maximum core inlet temperature, and TS minimum RCS flow. EC287528

The key input parameters and their values used in the analysis of this event were consistent with, or conservative relative to, the approved Reference 15.3-8 methodology. See Table 15.0-27 for key input parameter values.

- Reactivity Feedback – Because this event involves an increase in core coolant temperatures, the event was assumed to occur at BOC, with a TS maximum MTC. A minimum full-power scram worth was used, to conservatively maintain relatively high reactor power during the degradation in flow.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, control rod insertion was delayed to account for the CEA holding coil release delay time.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and PORVs) parameters and equipment states were selected to reduce the primary system pressure, which provided a conservative calculation of the MDNBR during the transient.

- Gap Conductance – The fuel-to-cladding gap conductance was set to a BOC (i.e., low) value that accounts for fuel TCD, to delay the transfer of heat from the fuel rod to the coolant, allowing the primary system flow to decay further before the cladding heat flux begins to be affected by the reactor trip, thus leading to a conservative prediction of DNBR.

- RCS Flow – A conservative pump coastdown model was used for this event.
- SGTP – The maximum of 20% tube plugging in each SG was analyzed.

EC287528

15.3.2.3 Results

Figures 15.3.2-1 through 15.3.2-8 illustrate the transient response for the complete loss-of-flow case. All RCPs decelerate at a constant rate until a reactor trip on low flow is initiated. The design DNBR limit is met.

The calculated sequence of events for the complete loss-of-flow case is shown on Table 15.3.2-1. Following reactor trip, the RCPs will continue to coast down, and natural circulation flow will eventually be established. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

AREVA Analysis

The sequence of events is given in Table 15.3.2-2. The result is given in Table 15.3.2-3. Statepoints for the DNB analyses were chosen at, or near, the time of the most adverse combination of power and flow. The MDNBR with statistically applied uncertainties was calculated to be greater than the 95/95 DNB correlation limit.

EC287528

Plots of key system parameters are shown in Figure 15.3.2-9 through Figure 15.3.2-14. Figure 15.3.2-9 shows the reactor power as a function of time. Figure 15.3.2-10 shows the core power based on rod surface heat flux. Figure 15.3.2-11 shows the pressurizer pressure. Figure 15.3.2-12 shows the RCS loop temperatures. Figure 15.3.2-13 shows the total RCS flow rate. Figure 15.3.2-14 shows the reactivity feedback.

15.3.2.4 Conclusions

The analysis performed has demonstrated that for the complete loss-of-flow event, the DNBR does not decrease below the design limit value at any time during the transient. Therefore, no fuel or cladding damage is predicted and all applicable acceptance criteria are met. The maximum RCS primary and secondary system pressures for this event are bounded by that of the loss-of-condenser vacuum event (Section 15.2.3).

15.3.3 REACTOR COOLANT PUMP SHAFT SEIZURE (LOCKED ROTOR)

15.3.3.1 Accident Description

The postulated locked-rotor accident is an instantaneous seizure of an RCP rotor. Flow through the affected reactor coolant loop is rapidly reduced, leading to an initiation of a reactor trip on a low-flow signal. The consequences of a postulated pump shaft break accident are similar to the locked-rotor event. With a broken shaft, the impeller is free to spin, as opposed to it being fixed in position during the locked-rotor event. Therefore, the initial rate of reduction in core flow is greater during a locked-rotor event than in a pump shaft break event because the fixed shaft causes greater resistance than a free-spinning impeller early in the transient, when flow through the affected loop is in the positive direction. As the transient continues, the flow direction through the affected loop is reversed. If the impeller is able to spin free, the flow to the core will be less than that available with a fixed-shaft during periods of reverse flow in the affected loop. Because peak pressure, cladding temperature, and DNB occur very early in the transient, the

reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Consequently, the bounding results for the locked-rotor transients also are applicable to the RCP shaft break.

After the locked rotor, reactor trip is initiated on an RCS low-flow signal. Failure of the fast bus transfer (FFBT) is assumed to occur at the time of reactor trip breaker opening. The failure of the fast bus transfer at the time of reactor trip breaker opening results in the coastdown of two of the three unfaulted reactor coolant pumps. The remaining unfaulted RCP is assumed to coastdown at 3.0 seconds following reactor trip breaker opening due to a loss of offsite power (LOOP).

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transferred to the shell side of the steam generators is reduced. This is because, first, the reduced flow results in a decreased tube-side film coefficient; and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORVs, and opens the pressurizer safety valves, in that sequence. The two PORVs are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism in the peak-pressure evaluation, the pressure-reducing effect of the pressurizer sprays and PORVs are not included in the analysis.

The locked-rotor event is analyzed to the following criteria:

- Pressure in the RCS should be maintained below the designated limit (see below).
- Coolable core geometry is ensured by showing that the peak cladding temperature and maximum oxidation level for the hot spot are below 2375°F and 16.0 percent by weight, respectively.
- Activity release is such that the calculated doses meet the guidelines established for design basis accidents.

For St. Lucie Unit 2, the locked-rotor RCS pressure limit is equal to 110 percent of the design value, or 2750 psia. For the secondary side, the locked-rotor pressure limit is also assumed to be equal to 110 percent of design pressure, or 1100 psia. Since the loss of condenser vacuum analysis bounds the locked rotor with respect to MSS overpressurization, a specific MSS overpressurization analysis is not performed.

A hot-spot evaluation is performed to calculate the peak cladding temperature and maximum oxidation level. Finally, a calculation of the “rods-in-DNB” is performed for input to the radiological dose analysis.

15.3.3.2 Method of Analysis

The locked-rotor transient is analyzed with two computer codes. First, the RETRAN computer code (References 15.3-1 and 15.3-2) is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and

the primary-system pressure and temperature transients. The VIPRE computer code (15.0.14.5) is then used to calculate the thermal behavior of the fuel located at the core hot spot including the rods-in- DNB using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

For the case analyzed to determine the maximum RCS pressure and peak cladding temperature, the plant is assumed to be in operation under the most adverse steady-state operating conditions; that is, a maximum steady-state thermal power, maximum steady-state pressure, and maximum steady-state coolant average temperature. Thermal Design Flow is assumed for this case. The case analyzed to determine the rods-in-DNB utilizes the RTDP methodology. Initial reactor power, pressurizer pressure and RCS temperature are assumed to be at their nominal values as shown in Table 15.0-27. Minimum measured flow is also assumed.

A maximum, uniform, SGTP level of 10 percent was assumed in the RETRAN analysis. The effect of a flow asymmetry resulting from asymmetric tube plugging is addressed in the DNB analysis of the locked rotor statepoints.

A conservatively large absolute value of the Doppler-only power coefficient is used, along with the least-negative MTC limit for full-power operation. These assumptions maximize the core power during the initial part of the transient when the peak RCS pressures and hot-spot results are reached.

A conservatively low trip worth is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time.

Failure of the fast bus transfer (FFBT) is assumed to occur at the time of reactor trip breaker opening. The failure of the fast bus transfer at the time of reactor trip breaker opening results in the coastdown of two of the three unfaulted reactor coolant pumps. A loss-of-offsite-power is assumed 3.0 seconds following reactor trip breaker opening, resulting in the unaffected RCP losing power and coasting down.

For the peak RCS pressure evaluation, the initial pressure is conservatively set to 2395 psia to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. The peak RCS pressure transient is shown in Figure 15.3.3-6. Accounting for pressurizer level uncertainty yields a maximum RCS pressure value of 2705.0 psia.

Pump Coastdown and Local Flow Characteristics

Any potential impact of the two-pump local flow characteristics are offset by the following conservatisms and modeling techniques:

- In RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the two-pump coastdown.

- In VIPRE, the peak power assembly with the peak rod at the Fr design limit and a low peak- to-average power ratio is modeled at the core location corresponding to the minimum flow assembly.

- In estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate Fr corresponding to the DNB SAFDL. By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

For this accident, an evaluation of the consequences with respect to the fuel rod thermal transient is performed. The evaluation incorporates the assumption of rods going into DNB as a conservative initial condition to determine the cladding temperature and zirconium water reaction resulting from the locked rotor. Results obtained from the analysis of this hot-spot condition represent the upper limit with respect to cladding temperature and zirconium water reaction.

Film Boiling Coefficient

The film boiling coefficient is calculated in the VIPRE code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature. The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and RCS flow rate as a function of time are based on the RETRAN results.

Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and cladding. Therefore, a conservatively large heat transfer gap coefficient is assumed, resulting in a conservative dissipation of the energy stored in the fuel to the cladding at the initiation of the transient.

Zirconium-Steam Reaction

The Baker-Just parabolic rate equation is used to define the rate of zirconium-steam reaction. The effect of the zirconium-steam reaction is included in the calculation of the hot-spot cladding temperature transient.

AREVA DNB Analysis

For the fuel transition, detailed analyses were performed with the approved Reference 15.3-8 non-LOCA methodology. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.3-9), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.3-10). EC287528

A single case was analyzed for DNBR at BOC full-power initial conditions, TS maximum core inlet temperature, and TS minimum RCS flow rate.

The key input parameters and their values used in the analysis of this event were consistent with, or conservative relative to, the approved Reference 15.3-8 methodology. See Table 15.0-27 for key input parameter values.

- Reactivity Feedback – Because this event involves an increase in the core coolant temperatures, the event was assumed to occur at BOC with the TS / Core Operating Limits Report (COLR) maximum MTC at or below 70% RTP. A minimum full-power scram worth, assuming the most reactive rod is stuck out of the core, was used, to conservatively maintain relatively high reactor power during the degradation in flow.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, control rod insertion was delayed to account for the CEA holding coil release delay time.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and PORVs) parameters and equipment states were selected to reduce the primary system pressure, which provided a conservative calculation of the MDNBR during the transient. EC287528

- Gap Conductance – The fuel-to-cladding gap conductance was set to a BOC (i.e., low) value that accounts for fuel TCD, to delay the transfer of heat from the fuel rod to the coolant, allowing the primary system flow to decay further before the cladding heat flux begins to be affected by the reactor trip, thus leading to a conservative prediction of DNBR.

- RCS Flow – A conservative pump coastdown model was used for this event.

- SGTP – The maximum of 20% tube plugging in each SG was analyzed.

15.3.3.3 Results

Figures 15.3.3-1 through 15.3.3-9 illustrate the transient response for the locked-rotor event. The peak RCS pressure is less than the acceptance criterion of 2750 psia. Also, the peak cladding temperature is considerably less than the limit of 2375°F. The zirconium-steam reaction at the hotspot meets the criterion of less than 16-percent zirconium-steam water reaction. For the radiological dose evaluation, the total percentage of fuel rods calculated to experience DNB is less than 2.5 percent (rods-in-DNB case). The sequence of events for the DNB case is given in Table 15.3.3-1.

AREVA DNB Analysis

The sequence of events is given in Table 15.3.3-1a. The result is given in Table 15.3.3-1b. The MDNBR was calculated to be greater than the 95/95 limit for the HTP DNB correlation.

Plots of key system parameters are shown in Figure 15.3.3-10 through Figure 15.3.3-16. EC287528
Figure 15.3.3-10 shows the reactor power as a function of time. Figure 15.3.3-11 shows the core power based on rod surface heat flux. Figure 15.3.3-12 shows the pressurizer pressure. Figure 15.3.3-13 shows the RCS loop temperatures. Figure 15.3.3-14 shows the total RCS flow rate. Figure 15.3.3-15 shows the loop flow rates. Figure 15.3.3-16 shows the reactivity feedback.

15.3.3.4 Radiological Analysis

15.3.3.4.1 Background

This event is caused by an instantaneous seizure of a primary reactor coolant pump rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow signal. Fuel damage may be predicted to occur as a result of this accident. Due to the pressure differential between the primary and secondary systems and assumed steam generator tube leakage, fission products are discharged from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere from the secondary coolant system through the steam generator via the ADVs and MSSVs. In addition, radioactivity is contained in the primary and secondary coolant before the accident and some of this activity is released to the atmosphere as a result of steaming from the steam generators following the accident. The St. Lucie Unit 2 AST dose analysis methodology is presented in NAI-1101-044, “AST Licensing Technical Report for St. Lucie Unit 2”.

15.3.3.4.2 Compliance with RG 1.183 Regulatory Positions

The revised Locked Rotor dose consequence analysis is consistent with the guidance provided in RG 1.183, Appendix G, "Assumptions for Evaluating the Radiological Consequences of a PWR Locked Rotor Accident," as discussed below:

The Locked Rotor dose consequence analysis followed the guidance provided in RG 1.183, Appendix G, "Assumptions for Evaluating the Radiological Consequences of a PWR Locked Rotor Accident," as discussed below:

1. Regulatory Position 1 - The total core inventory of the radionuclide groups utilized for determining the source term for this event is based on RG 1.183, Regulatory Position 3.1, and is provided in Table 15.0-32. The inventory provided in Table 15.0-32 is adjusted for the fraction of fuel damaged and a radial peaking factor of 1.65 is applied. The fraction of fission product inventory in the gap available for release due to fuel breach is consistent with Table 3 of RG 1.183.

2. Regulatory Position 2 - Fuel damage is assumed for this event.

3. Regulatory Position 3 - Activity released from the damaged fuel is assumed to mix instantaneously and homogeneously throughout the primary coolant.

4. Regulatory Position 4 - The chemical form of radioiodine released from the damaged fuel is assumed to be 95% cesium iodide (CsI), 4.85% elemental iodine, and 0.15% organic iodide. Iodine releases from the SGs to the environment are assumed to be 97% elemental and 3% organic. These fractions apply to iodine released as a result of fuel damage and to equilibrium iodine concentrations in the RCS and secondary system.

5. Regulatory Position 5.1 - The primary-to-secondary leak rate is apportioned between the SGs as specified by TS 6.8.4.l (0.5 gpm total, 0.25 gpm to any one SG). Thus, the tube leakage is apportioned equally between the two SGs.

6. Regulatory Position 5.2 - The density used in converting volumetric leak rates to mass leak rates is based upon RCS conditions, consistent with the plant design basis.

7. Regulatory Position 5.3 - The primary-to-secondary leakage is assumed to continue until after shutdown cooling has been placed in service and the temperature of the RCS is less than 212°F.

8. Regulatory Position 5.4 - The analysis assumes a coincident loss of offsite power in the evaluation of fission products released from the secondary system.

9. Regulatory Position 5.5 - All noble gas radionuclides released from the primary system are assumed released to the environment without reduction or mitigation.

10. Regulatory Position 5.6 - Regulatory Position 5.6 refers to Appendix E, Regulatory Positions 5.5 and 5.6. The iodine transport model for release from the steam generators is as follows:

    - Appendix E, Regulatory Position 5.5.1 - Both steam generators are used for plant cooldown. A portion of the primary-to-secondary leakage is assumed to flash to vapor based on the thermodynamic conditions in the reactor and secondary immediately following plant trip when tube uncovery is postulated. The primary-to-secondary leakage is assumed to mix with the secondary water without flashing during periods of total tube submergence.

    - Appendix E, Regulatory Position 5.5.2 - The portion of leakage that immediately flashes to vapor is assumed to rise through the bulk water of the SG, enter the steam space, and be immediately released to the environment with no mitigation; i.e., no reduction for scrubbing within the SG bulk water is credited.

    - Appendix E, Regulatory Position 5.5.3 - All of the SG tube leakage that does not flash is assumed to mix with the bulk water.

    - Appendix E, Regulatory Position 5.5.4 - The radioactivity within the bulk water is assumed to become vapor at a rate that is a function of the steaming rate and the partition coefficient. A partition coefficient of 100 is assumed for the iodine. The retention of particulate radionuclides in the SGs is limited by the moisture carryover from the SG. The same partition coefficient of 100, as used for iodine, is assumed for other particulate radionuclides. This assumption is consistent with the SG carryover rate of less than 1%.

    - Appendix E, Regulatory Position 5.6 - Steam generator tube bundle uncovery in the SGs is postulated for up to 45 minutes following a reactor trip for St. Lucie Unit 2. During this period, the fraction of primary-to-secondary leakage which flashes to vapor is assumed to rise through the bulk water of the SG into the steam space and is assumed to be immediately released to the environment with no mitigation. The flashing fraction is based on the thermodynamic conditions in the reactor and secondary coolant. The leakage which does not flash is assumed to mix with the bulk water in the steam generator. A conservative uncovery time of 60 seconds was assumed in the analysis.

15.3.3.4.3 Other Assumptions

1. RG 1.183, Section 3.6 - The assumed amount of fuel damage caused by the non-LOCA events is analyzed to determine the fraction of the fuel that reaches or exceeds the initiation temperature of fuel melt and to determine the fraction of fuel elements for which fuel clad is breached. This analysis assumes DNB as the fuel damage criterion for estimating fuel damage for the purpose of establishing radioactivity releases. For the Locked Rotor event, Table 3 of RG 1.183 specifies noble gas, alkali metal, and iodine fuel gap release fractions for the breached fuel.

2. The initial RCS activity is assumed to be at the TS 3.4.8 limit of 1.0 μCi/gm Dose Equivalent I-131 and 518.9 μCi/gm DE Xe-133 gross activity. The initial SG activity is assumed to be at the TS 3.7.1.4 limit of 0.1 μCi/gm Dose Equivalent I-131.

3. The steam mass release rates for the SGs are provided in Table 15.3.3-4.

4. The RCS fluid density used to convert the primary-to-secondary leakage from a volumetric flowrate to a mass flow rate is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. The high initial cooldown rate conservatively maximizes the fluid density. The SG tube leakage mass flow rate is provided in Table 15.3.3-5.

5. This RCS mass is assumed to remain constant throughout the event.

6. For the purposes of determining the iodine concentrations, the SG mass is assumed to remain constant throughout the event. However, it is also assumed that operator action is taken to restore secondary water level above the top of the tubes within a conservative time of one hour following a reactor trip.

7. This analysis assumes that the DNB fuel damage is limited to 19.7% breached fuel assemblies.

15.3.3.4.4 Methodology

Input assumptions used in the dose consequence analysis of the Locked Rotor event are provided in Table 15.3.3-3. This event is caused by an instantaneous seizure of a primary reactor coolant pump rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow signal. Following the reactor trip, the heat stored in the fuel rods continues to be transferred to the reactor coolant. Because of the reduced core flow, the coolant temperatures will rise. The rapid rise in primary system temperatures during the initial phase of the transient results in a reduction in the initial DNB margin and fuel damage.

For the purpose of this dose assessment, a total of 19.7% of the fuel assemblies are assumed to experience DNB. The activity released from the fuel is assumed to be released instantaneously and homogeneously through the primary coolant. The source term is based upon release fractions from Appendix G of RG 1.183 with a radial peaking factor of 1.65. Primary coolant is released to the SGs as a result of postulated primary-to-secondary leakage. Activity is released to the atmosphere via steaming from the steam generator ADVs until the RCS is cooled to 212°F. These release assumptions are consistent with the requirements of RG 1.183.

For this event, the Control Room ventilation system cycles through three modes of operation:

- Initially the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 395 cfm of unfiltered inleakage.

- After the start of the event, the Control Room is isolated due to a high radiation reading in the Control Room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 395 cfm of unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

- At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.

- The Control Room ventilation filter efficiencies that are applied to the filtered makeup and recirculation flows are 99% for particulate, and 95% for elemental iodine, and organic iodine.

15.3.3.4.5 Radiological Consequences

The atmospheric dispersion factors (χ/Qs) used for this event for the Control Room dose are based on the postulated release locations and the operational mode of the control room ventilation system. The release-receptor point locations are chosen to minimize the distance from the release point to the Control Room air intake.

Releases are assumed to occur from the ADV that produces the most limiting χ/Qs. When the Control Room Ventilation System is in normal mode, the most limiting χ/Q corresponds to the worst air intake to the control room. When the ventilation system is isolated, the limiting χ/Q corresponds to the midpoint between the two control room air intakes. The operators are assumed to reopen the most favorable air intake at 1.5 hours. Development of control room atmospheric dispersion factors is discussed in Appendix 2.5D. These χ/Qs applied in the Seized Rotor analysis are summarized in Table 15.3.3-6.

The EAB and LPZ dose consequences are determined using the χ/Q factors provided in Appendix 2.5C for the appropriate time intervals. For the EAB dose analysis, the χ/Q factor for the zero to two-hour time interval is assumed for all time periods. Using the zero to two-hour χ/Q factor provides a more conservative determination of the EAB dose, because the χ/Q factor for this time period is higher than for any other time period.

The radiological consequences of the Locked Rotor event are analyzed using the RADTRAD-NAI code and the inputs/assumptions previously discussed. As shown in Table 15.3.3-2, the results for EAB dose, LPZ dose, and Control Room dose are all within the appropriate regulatory acceptance criteria.

15.3.3.5 Conclusions

The analysis performed has demonstrated that for the locked-rotor event, the RCS pressure remains below 110 percent of the design pressure and the hot-spot cladding temperature and oxidation levels remain below the limit values. Therefore, all applicable acceptance criteria are met. In addition, the total percentage of rods calculated to experience DNB is less than 2.5 percent; therefore, the criteria of Regulatory Guide 1.183 are satisfied. The potential for DNB propagation during the seized rotor event was also evaluated and found to not occur. Since the fuel failure is limited and DNB propagation is not postulated to occur a coolable geometry is maintained.

15.3.4 REACTOR COOLANT PUMP SHAFT BREAK

This accident is postulated as an instantaneous failure of an RCP shaft. RCS flow through the affected reactor coolant loop is rapidly reduced, though the initial rate of reduction of coolant flow is greater for the reactor coolant pump shaft seizure event. With a failed shaft, the pump impeller could conceivably be free to spin in the reverse direction instead of being fixed in position (as assumed in the locked rotor analysis). The net effect on core flow is negligible, resulting in only a slight decrease in the final (steady-state) core flow.

The analysis presented under the Reactor Coolant Pump Shaft Seizure (Locked Rotor) section (Section 15.3.3) represents the limiting condition, assuming a locked rotor for forward flow but a free-spinning shaft for reverse flow in the affected loop, even with the change to AREVA fuel. EC287528
Therefore, the conclusions for the RCP Shaft Seizure apply to and bound a reactor coolant pump shaft break event.

15.3.5 REFERENCES

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15.3-3. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

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15.3-5. CENPD-183-A, "CE Methods for Loss of Flow Analysis," June 1984.

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15.3-9 XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, August 1983. EC287528

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Table 15.3.2-1
Sequence of Events
Complete Loss of Reactor Coolant Flow

Event	**Time (seconds)***
All Operating RCPs Lose Power and Coastdown Begins	10.01
Low Flow Reactor Trip Setpoint is Reached	10.92
Rods Begin Motion (0.9 sec trip delay + 0.74 sec holding coil delay)	12.56
Minimum DNBR Occurs	14.30

* Note that the start of the event is preceded by a 10 second stead-state period. EC287528

Table 15.3.2-2 Complete Loss of Reactor Coolant Flow (AREVA): Sequence of Events

Event	Time (sec)
Pump coastdown initiates	0.00
Low RCS flow trip setpoint is reached	0.87
Reactor is scrammed on low RCS flow rate (including signal processing delay)	1.78
CEA insertion begins	2.52
Peak reactor power occurs	2.52
Peak pressurizer pressure occurs	3.09
MDNBR occurs	4.05
CEAs are fully inserted	5.37

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Table 15.3.2-3 Complete Loss of Reactor Coolant Flow (AREVA): Result

Criterion	Result	Limit
MDNBR	1.227	1.164

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Table 15.3.3-1 Sequence of Events Reactor Coolant Pump Locked Rotor with FFBT Rods-in-DNB Case	
Event	**Time (seconds)***
Rotor on One Pump Seizes	10.000
Low Flow Trip Reached	10.012
Reactor Trip Signal on Low RCS Flow	10.919
Failure of Fast Bus Transfer	10.929
Rod Begin to Drop	11.659
Minimum DNBR Occurs	13.300

* Note that the start of the event is preceded by a 10 second stead-state period.

Table 15.3.3-1a Reactor Coolant Pump Locked Rotor (AREVA DNB): Sequence of Events	
Event	Time (sec)
Event is initiated (seizure of RCP 1A)	0.00
Low RCS flow trip setpoint is reached	0.12
Reactor is scrammed on low RCS flow rate (including signal processing delay)	1.02
CEA insertion begins	1.76
Peak reactor power occurs	1.76
Peak pressurizer pressure occurs	2.04
MDNBR occurs	3.08
CEAs are fully inserted	4.61

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Table 15.3.3-1b Reactor Coolant Pump Locked Rotor (AREVA DNB): Result		
Criterion	Result	Limit
MDNBR (% fuel failure)	1.205 (0%)	1.164

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Table 15.3.3-2

Locked Rotor Dose Consequences

Case	EAB Dose (1) (rem TEDE)	LPZ Dose (2) (rem TEDE)	Control Room Dose (2) (rem TEDE)
Locked Rotor	0.37	0.92	4.35
Acceptance Criteria	2.5	2.5	5

(1) Worst 2-hour dose
(2) Integrated 30-day dose

Table 15.3.3-3

Reactor Coolant Pump Shaft Seizure (Locked Rotor) – Inputs and Assumptions

Input/Assumption	Value
Core Power Level	3030 MW_{th} (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o
Maximum Radial Peaking Factor	1.65
Percent of Fuel Rods in DNB	19.7%
Core Fission Product Inventory	Table 15.0-32
Initial RCS Equilibrium Activity	1.0 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 (Table 15.6.5-15)
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/gm DE I-131 (Table 15.1.6-6)
Release Fraction from Breached Fuel	RG 1.183, Section 3.2
Steam Generator Tube Leakage	0.5 gpm (Table 15.3.3-5)
Time to Terminate SG Tube Leakage	12.4 hours
Secondary Side Mass Releases to Environment	Table 15.3.3-4
SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	 1 hour 5 %
Steam Generator Secondary Side Partition Coefficient	Flashed tube flow – none Non-flashed tube flow – 100
Time to Reach 212 °F and Terminate Steam Release	12.4 hours
RCS Mass	420,090 lb_m Minimum mass used for fuel failure dose contribution to maximize SG tube leakage activity.

Table 15.3.3-3 (continued)

Reactor Coolant Pump Shaft Seizure (Locked Rotor) – Inputs and Assumptions

Input/Assumption	Value
SG Secondary Side Mass	minimum – 128,390 -5% lb_m (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration.
Atmospheric Dispersion Factors Offsite Onsite	 Appendix 2.5C Table 15.3.3-6
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	 30 seconds 1.5 hours 395 cfm
Breathing Rates Offsite Onsite	 RG 1.183 Section 4.1.3 RG 1.183 Section 4.2.6
Control Room Occupancy Factor	RG 1.183 Section 4.2.6

Table 15.3.3-4

Locked Rotor Steam Release Rate

Time (hours)	Steam Generator Steam Release Rate (lb_m/min)
0.0	11473.7
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0

Table 15.3.3-5

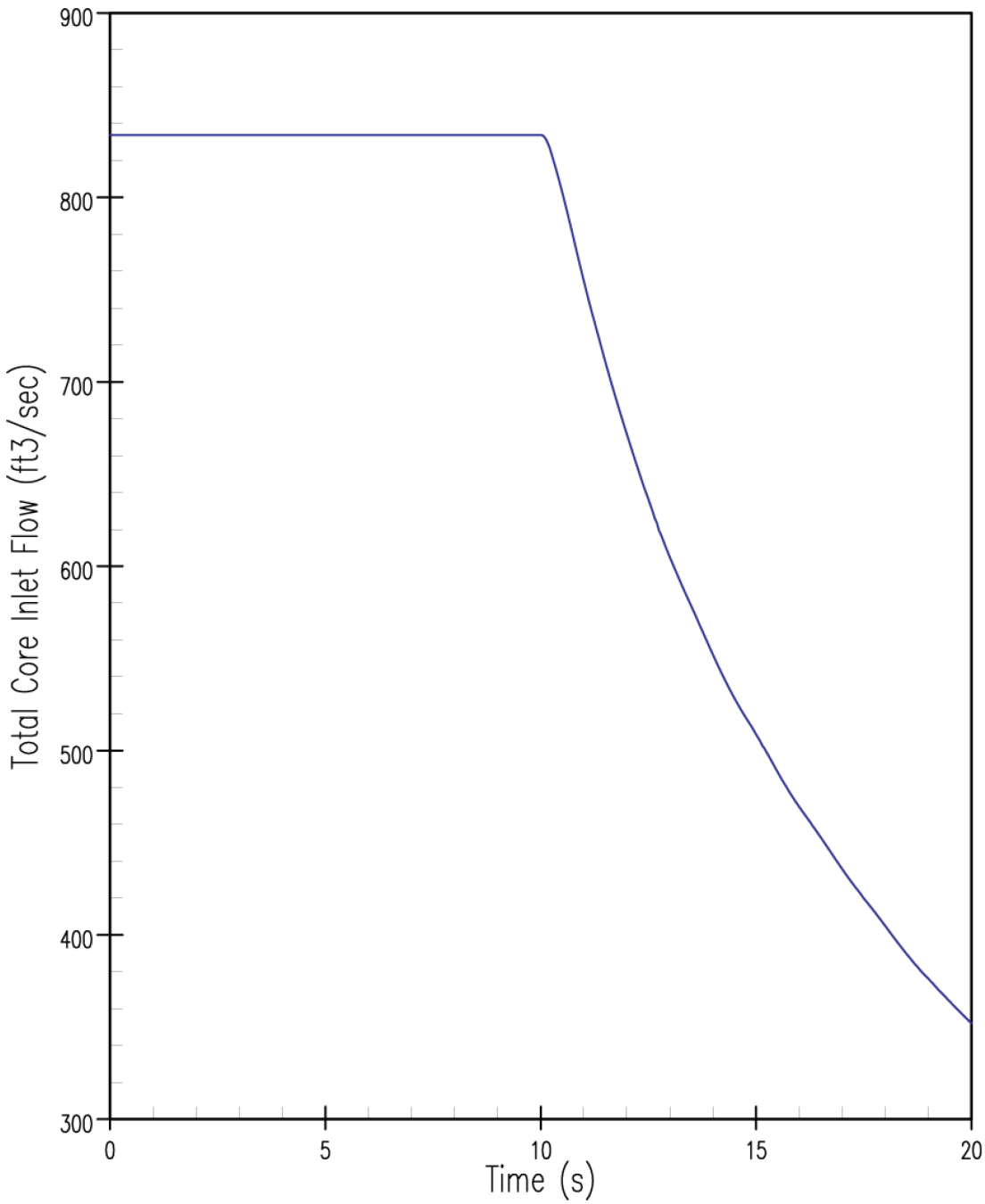
Locked Rotor SG Tube Leakage

Time (hours)	Steam Generator Tube Leakage (lb_m/min)
0	3.15
0.50	3.34
1.00	3.50
1.50	3.65
2.00	3.71
4.00	3.80
6.00	3.89
9.00	3.96
11.00	4.00
12.40	0.00

Table 15.3.3-6

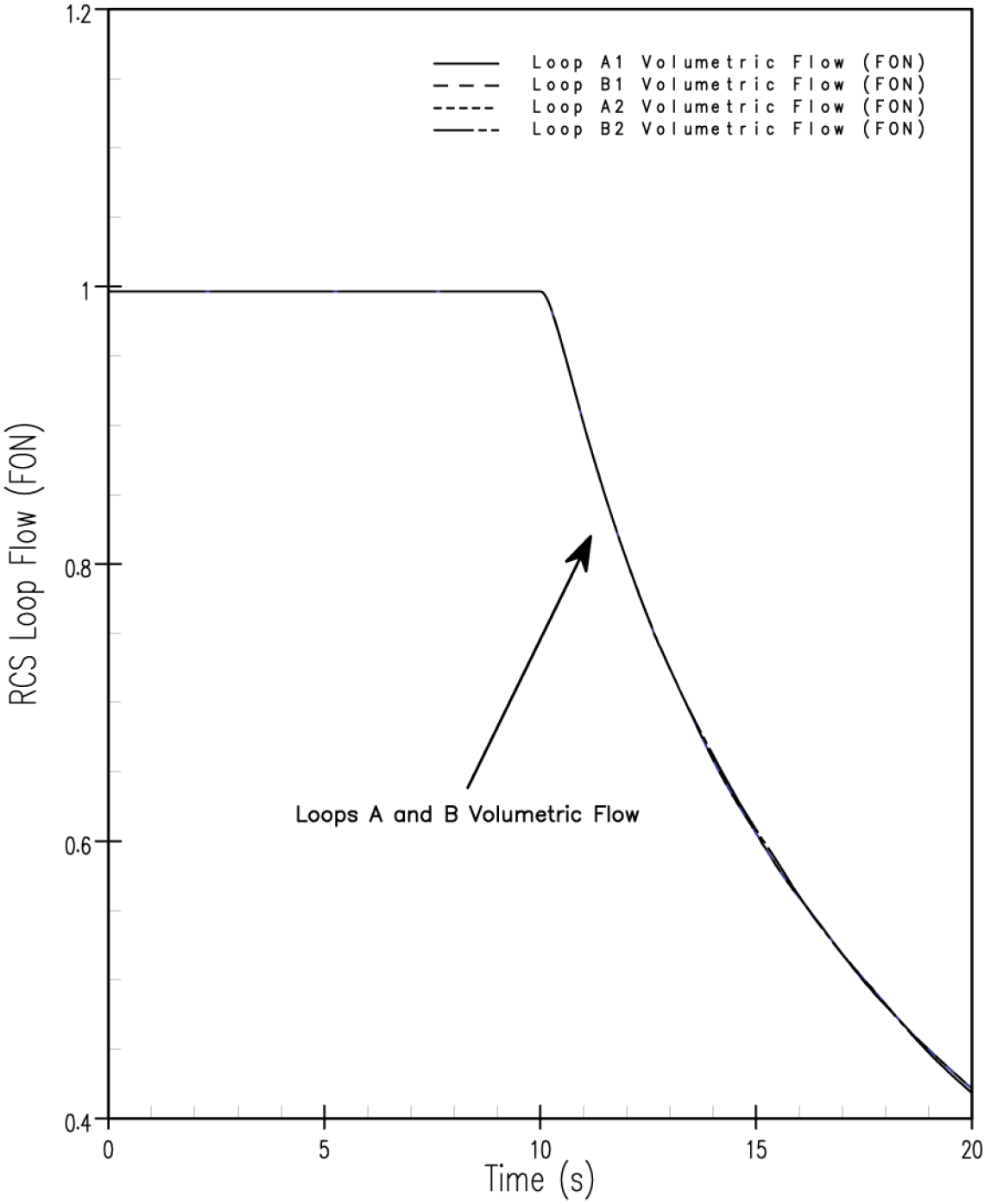
Control Room χ/Qs

Time (hours)	**χ/Q (sec/m^3)**
0	6.71E-03
0.00833	3.13E-03
1.5	1.89E-03
2	1.53E-03
8	6.02E-04
24	4.55E-04
96	3.89E-04
720	3.89E-04



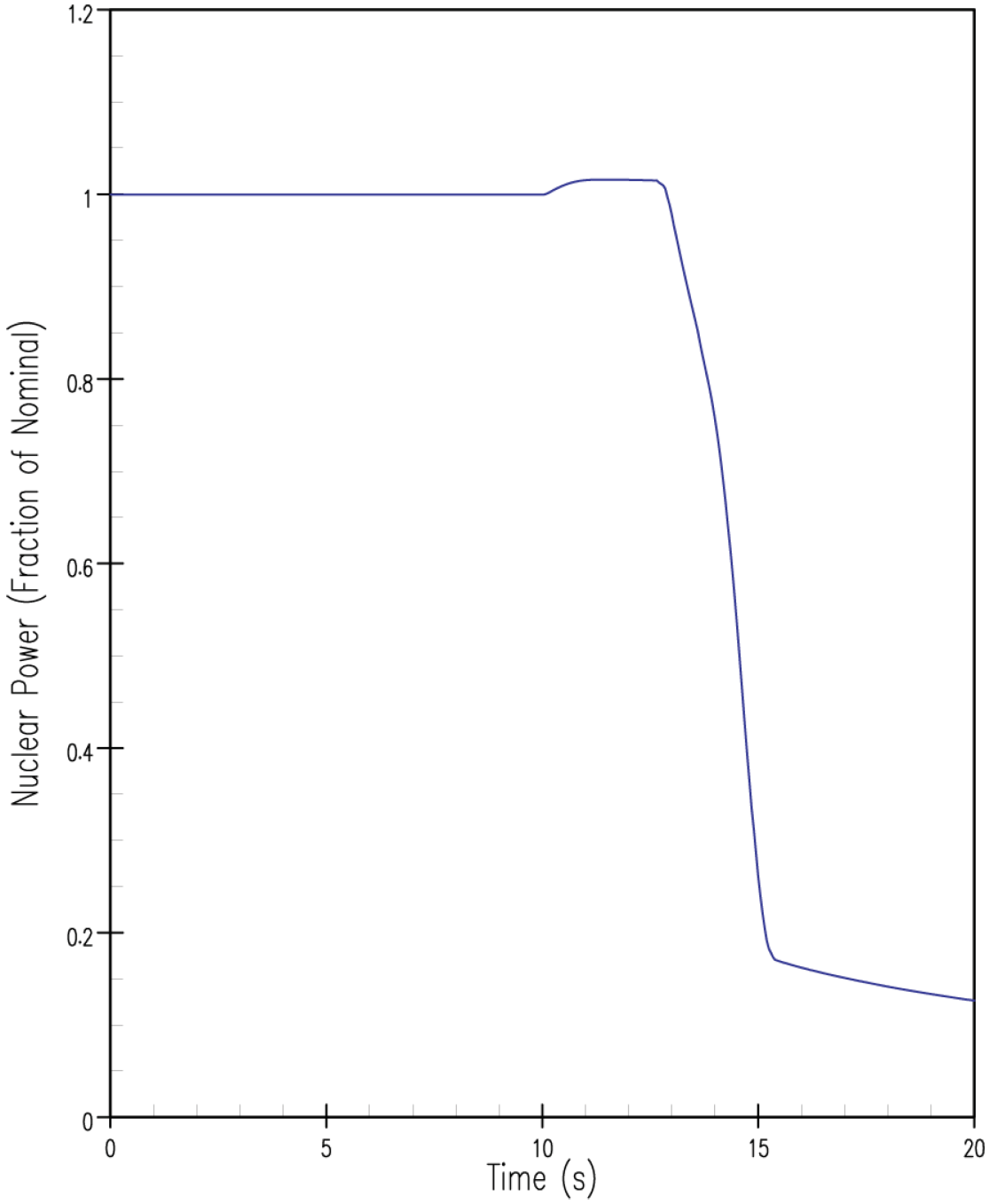
Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-1 Complete Loss of Flow – Four Pumps Coasting Down Total Core Inlet Flow versus Time



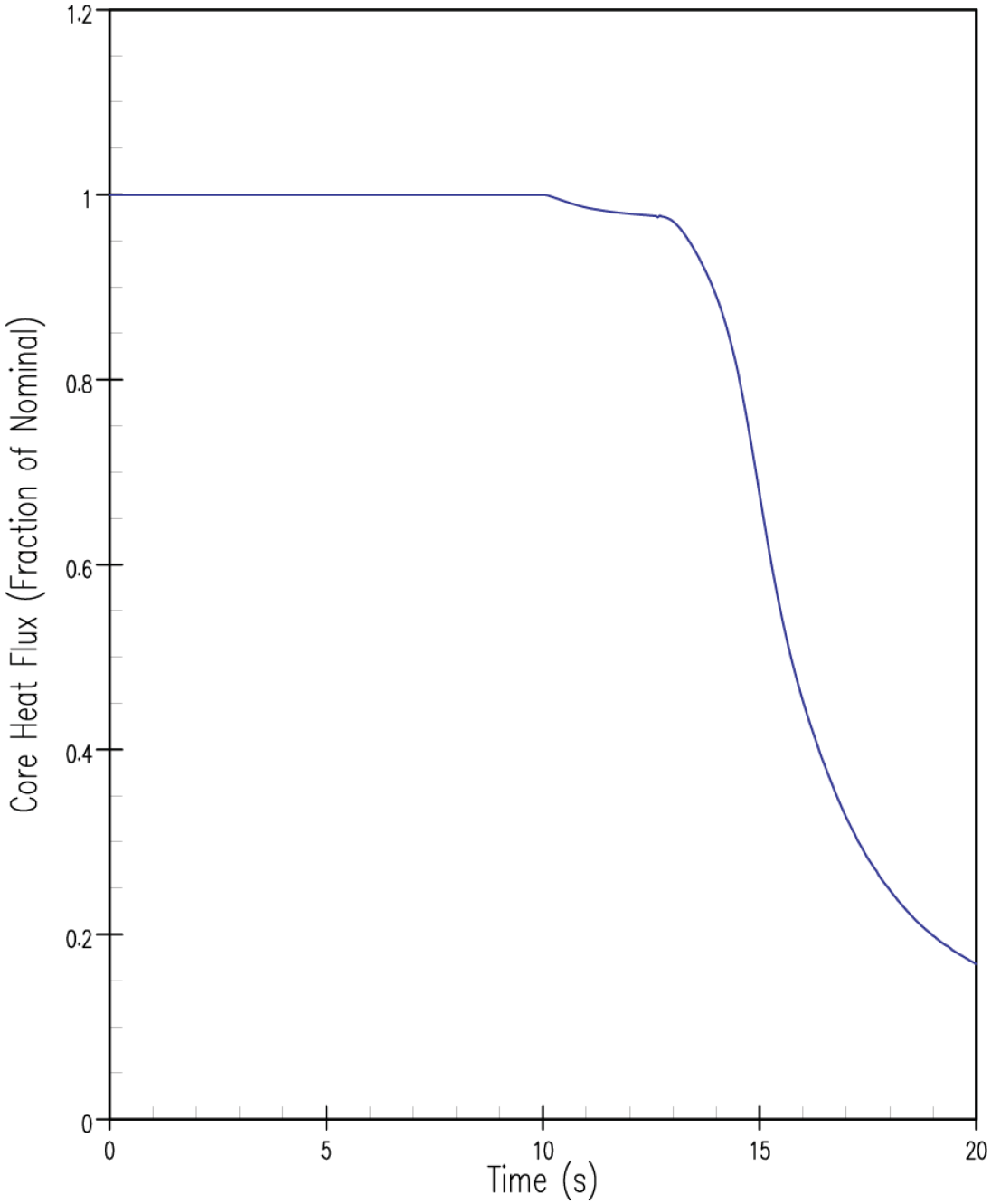
Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-2 Complete Loss of Flow – Four Pumps Coasting Down RCS Loop Flow versus Time



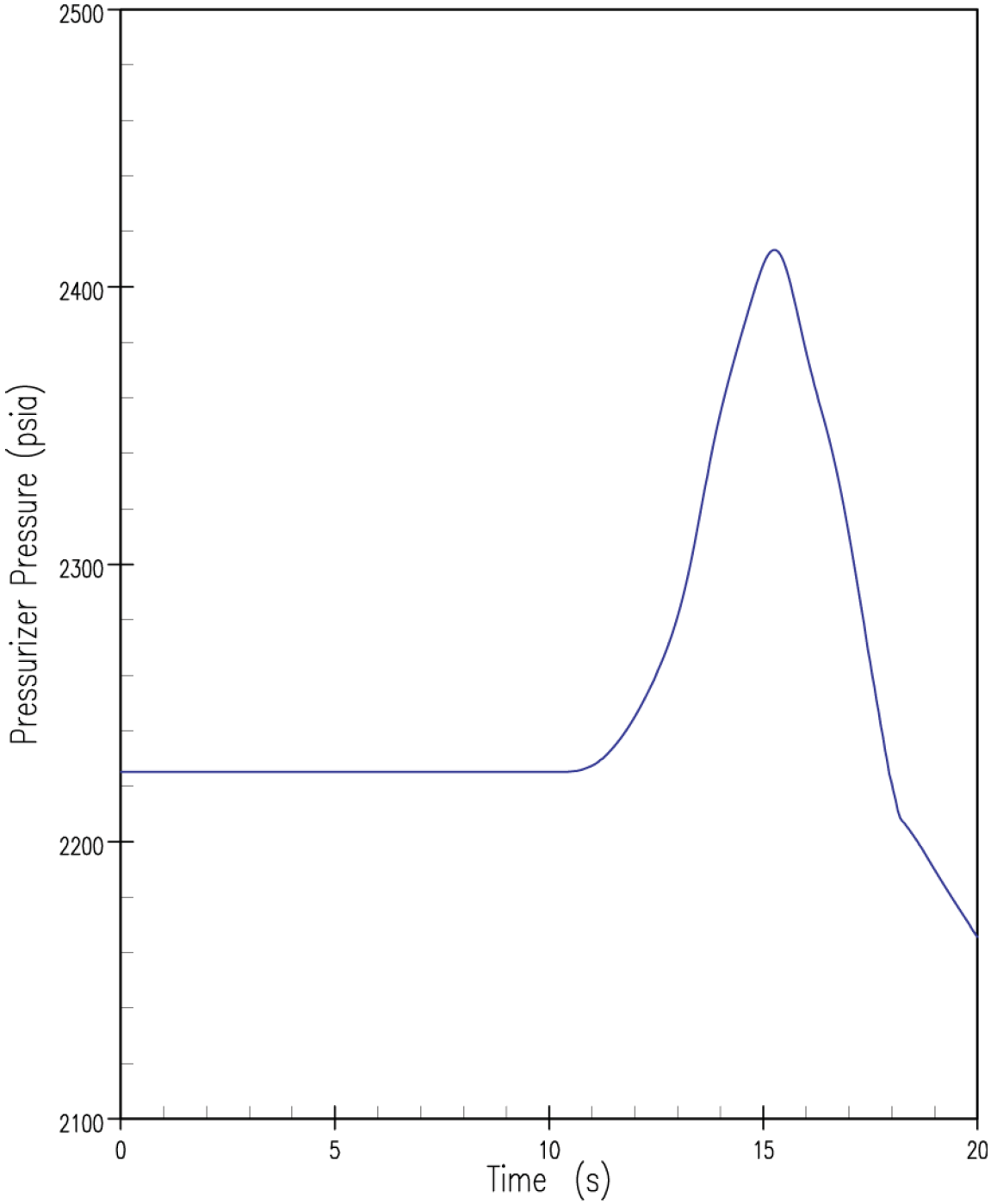
Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-3 Complete Loss of Flow – Four Pumps Coasting Down Nuclear Power versus Time



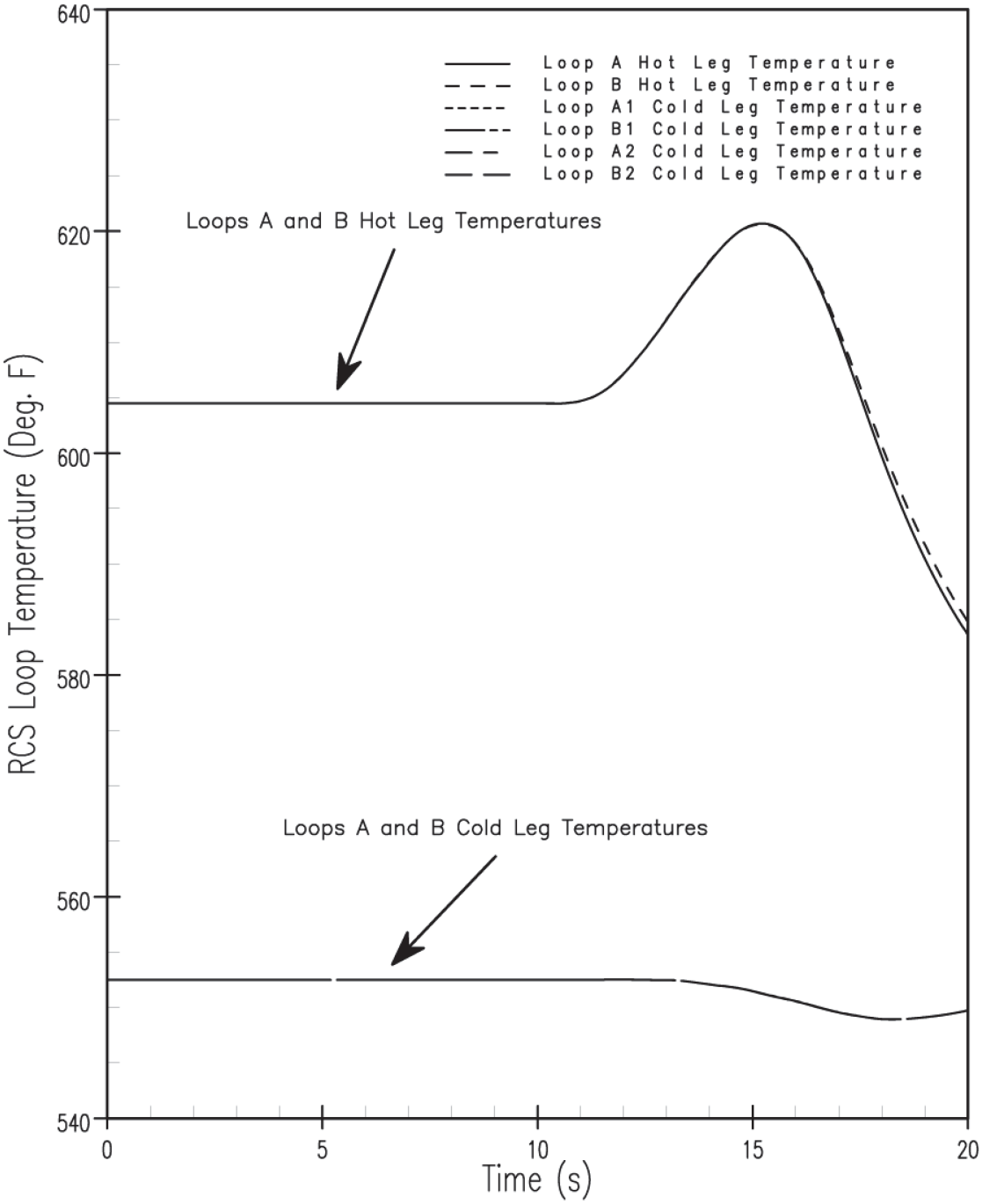
Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-4 Complete Loss of Flow – Four Pumps Coasting Down Core Average Heat Flux versus Time



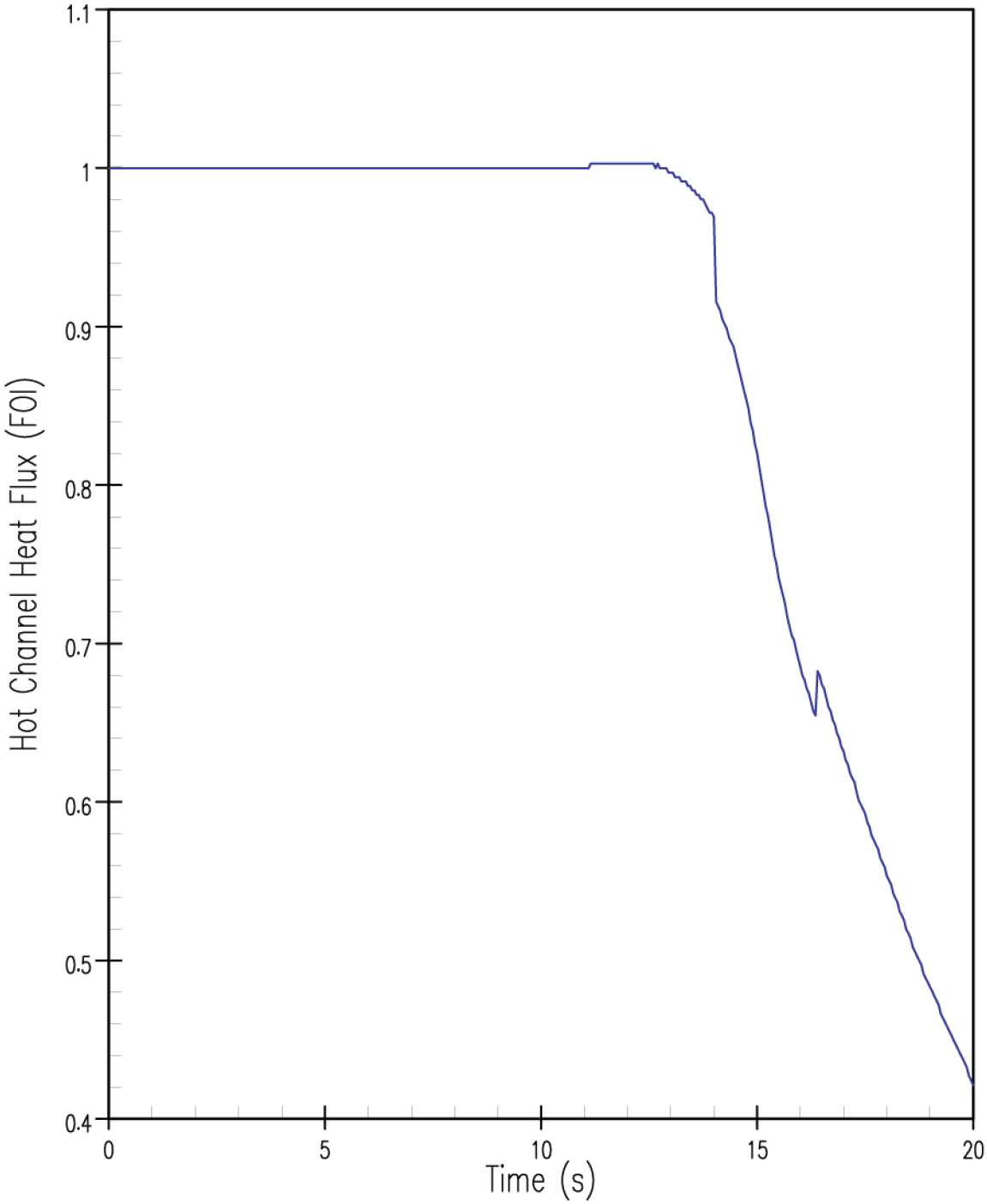
Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-5 Complete Loss of Flow – Four Pumps Coasting Down Pressurizer Pressure versus Time



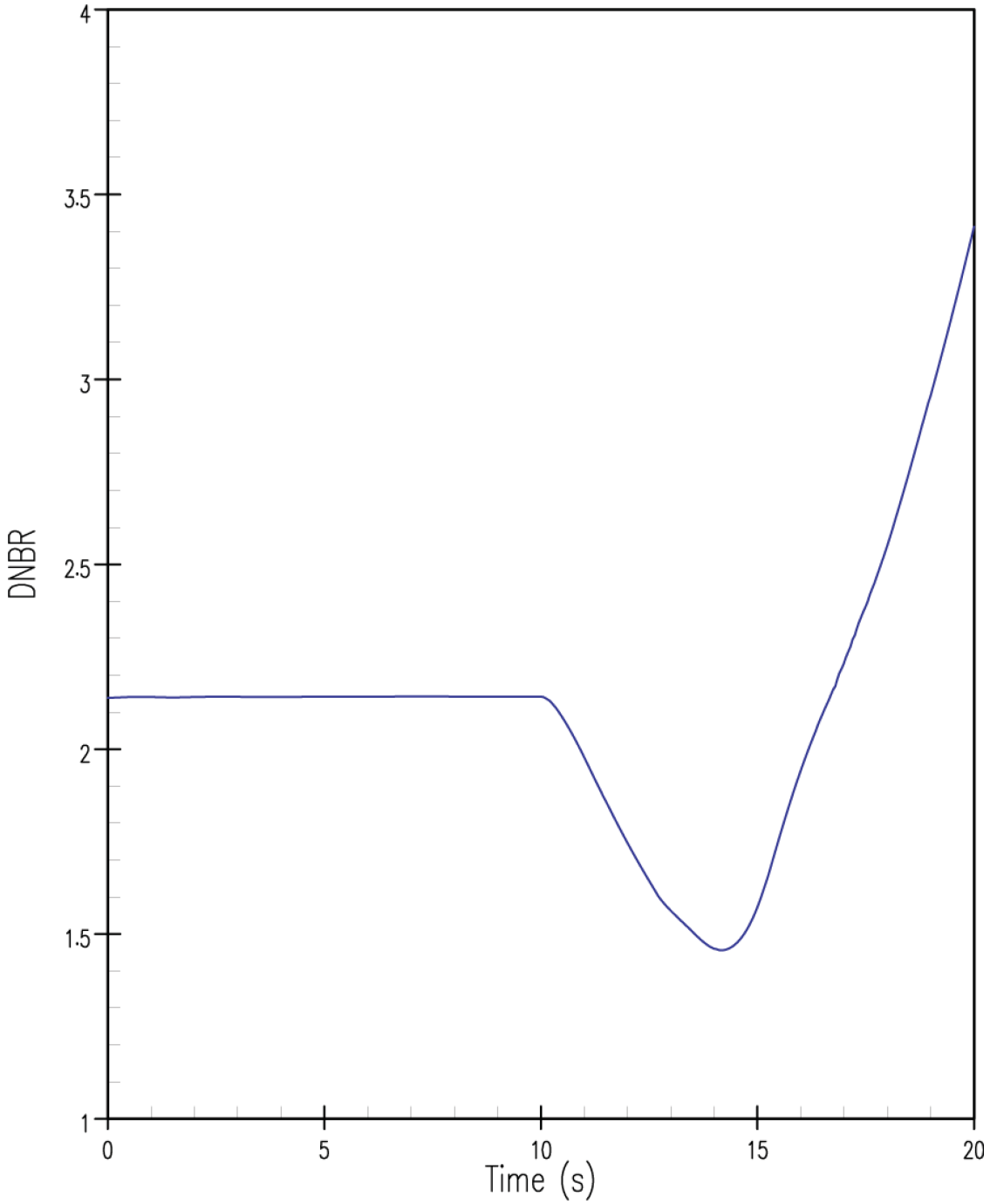
Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-6 Complete Loss of Flow – Four Pumps Coasting Down RCS Loop Temperature versus Time



Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-7 Complete Loss of Flow – Four Pumps Coasting Down Hot Channel Heat Flux versus Time



Note: The figure above includes the 10 second steady state.

FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.2-8 Complete Loss of Flow – Four Pumps Coasting Down DNBR versus Time

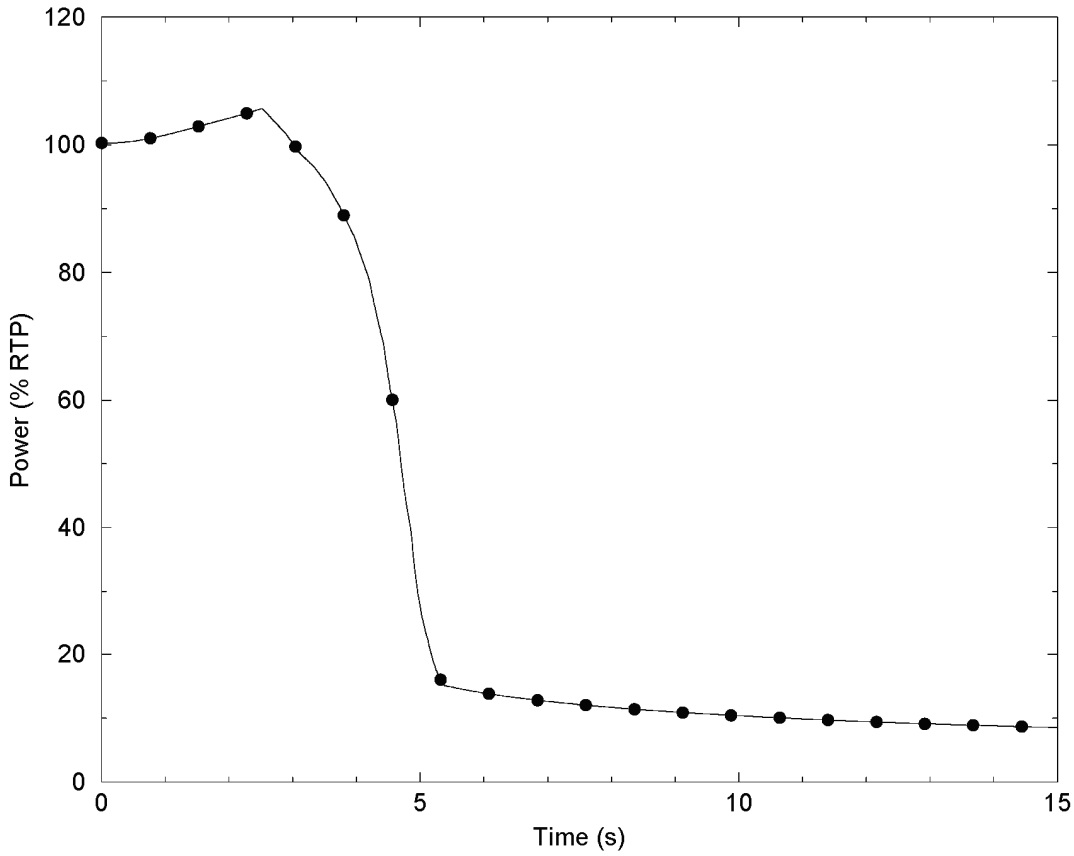


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Figure 15.3.2-9
Complete Loss of Flow (AREVA):
Reactor Power vs. Time

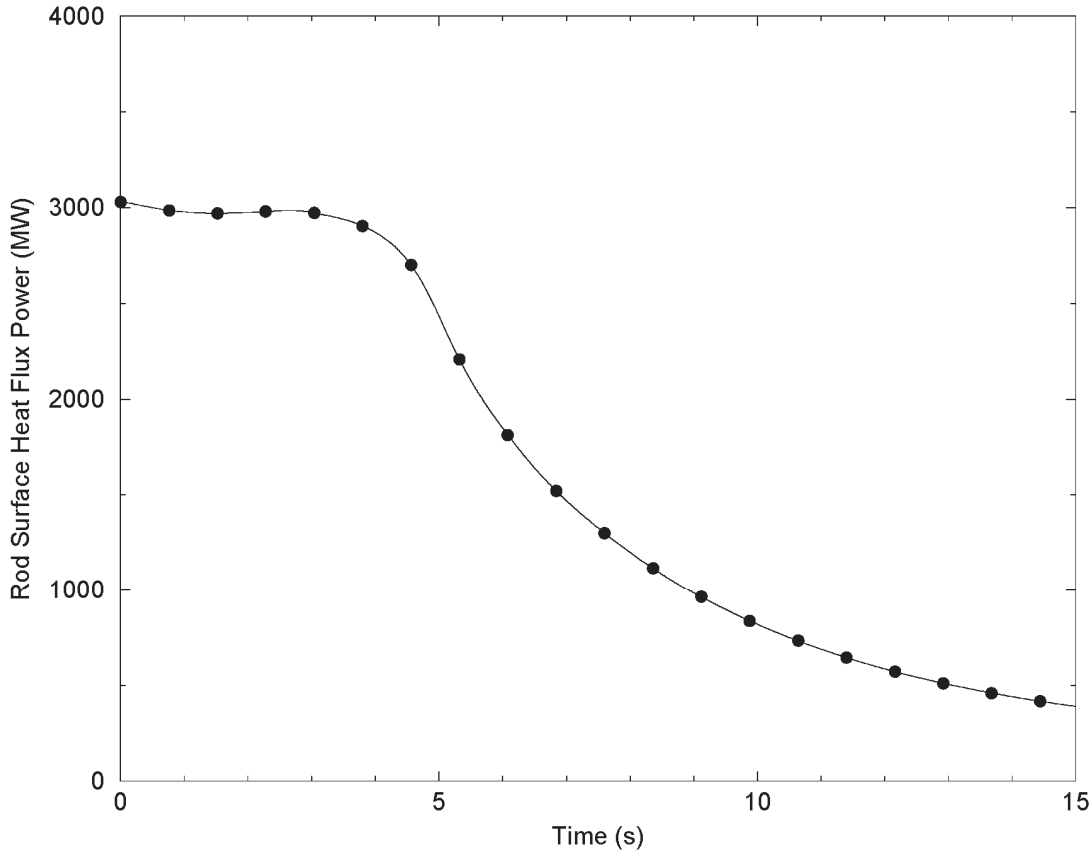

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Figure 15.3.2-10
Complete Loss of Flow (AREVA):
Total Core Heat Flux Power vs. Time

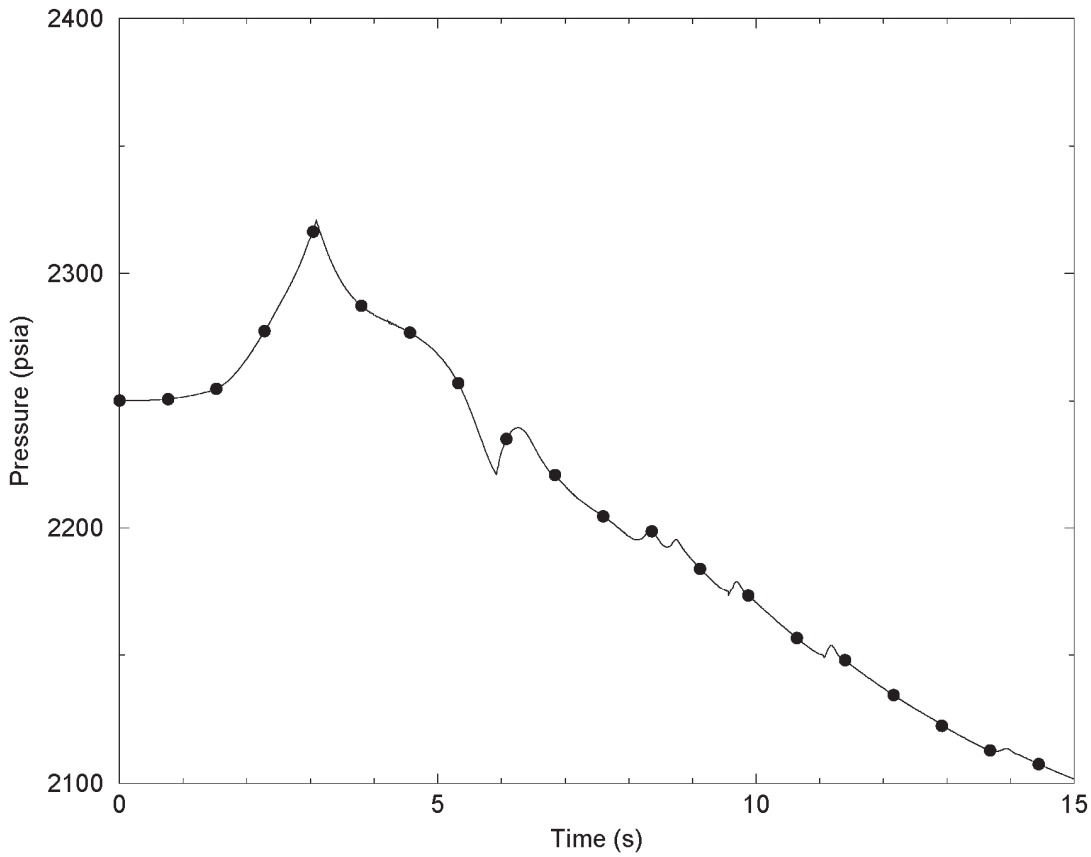

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Figure 15.3.2-11
Complete Loss of Flow (AREVA):
Pressurizer Pressure vs. Time

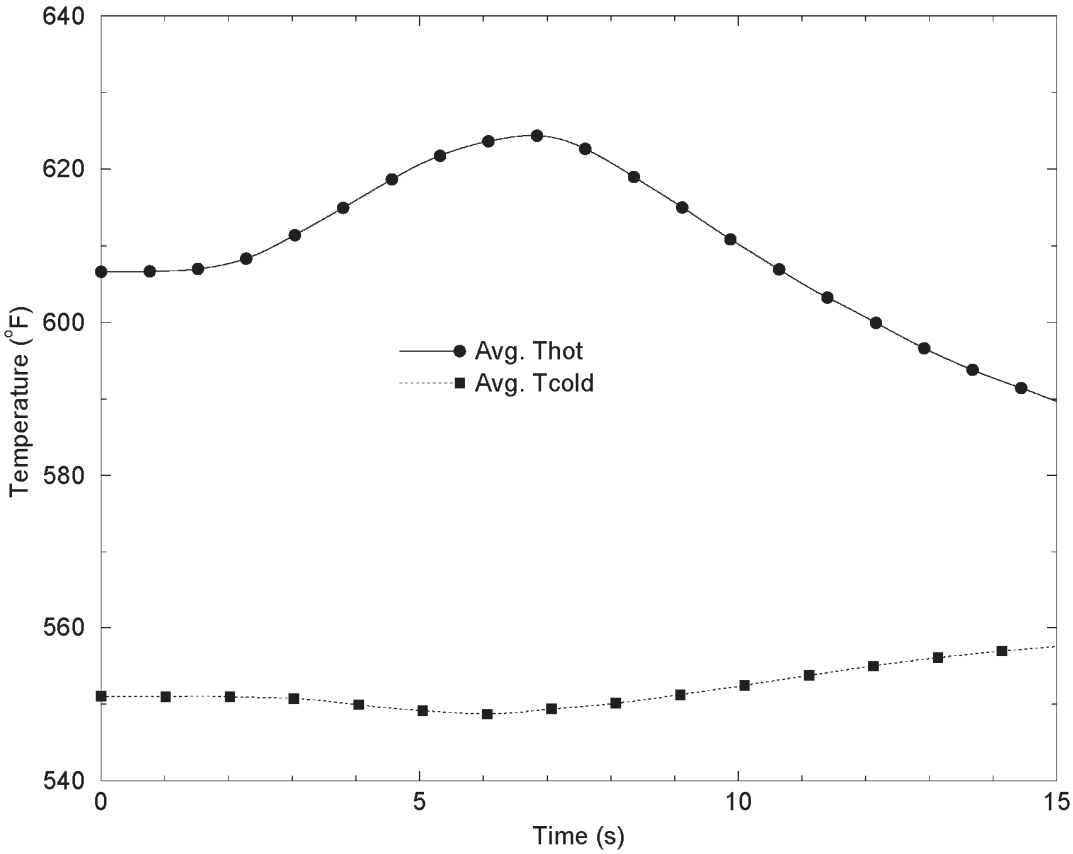

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Figure 15.3.2-12
Complete Loss of Flow (AREVA):
RCS Loop Temperatures vs. Time

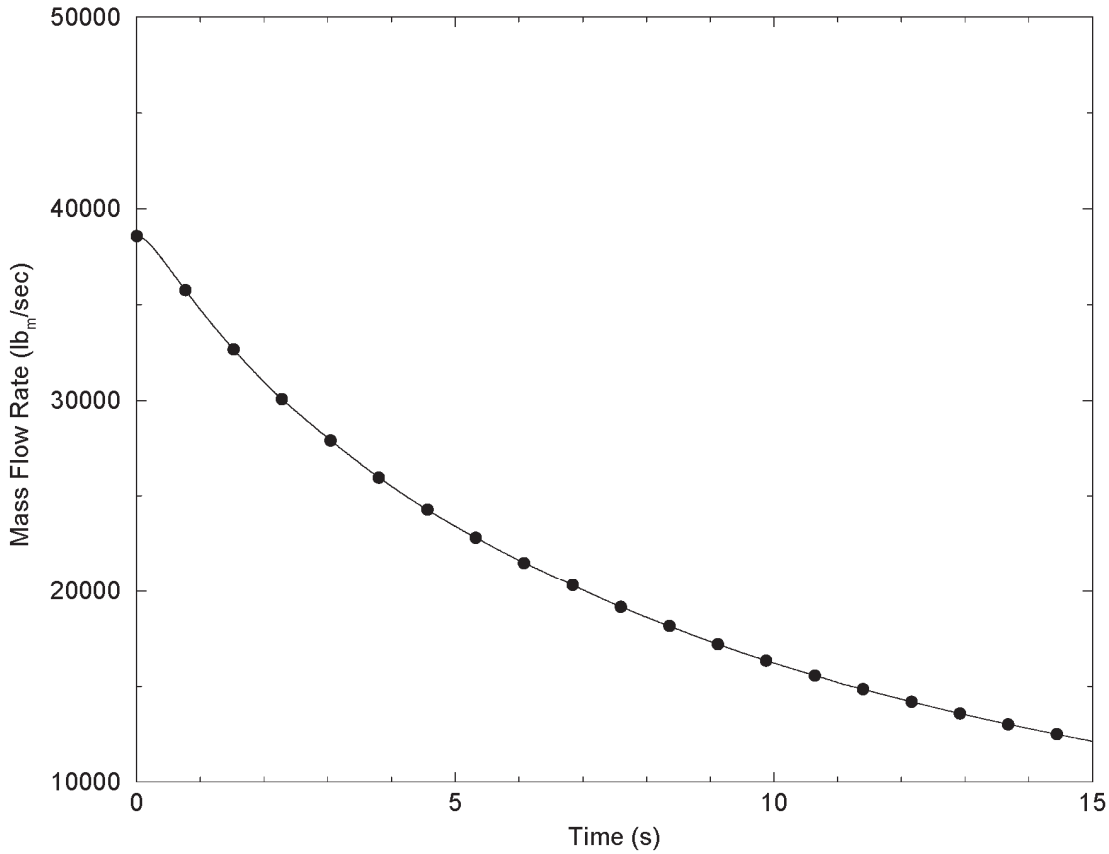

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Figure 15.3.2-13
Complete Loss of Flow (AREVA):
RCS Total Loop Flow Rate vs. Time

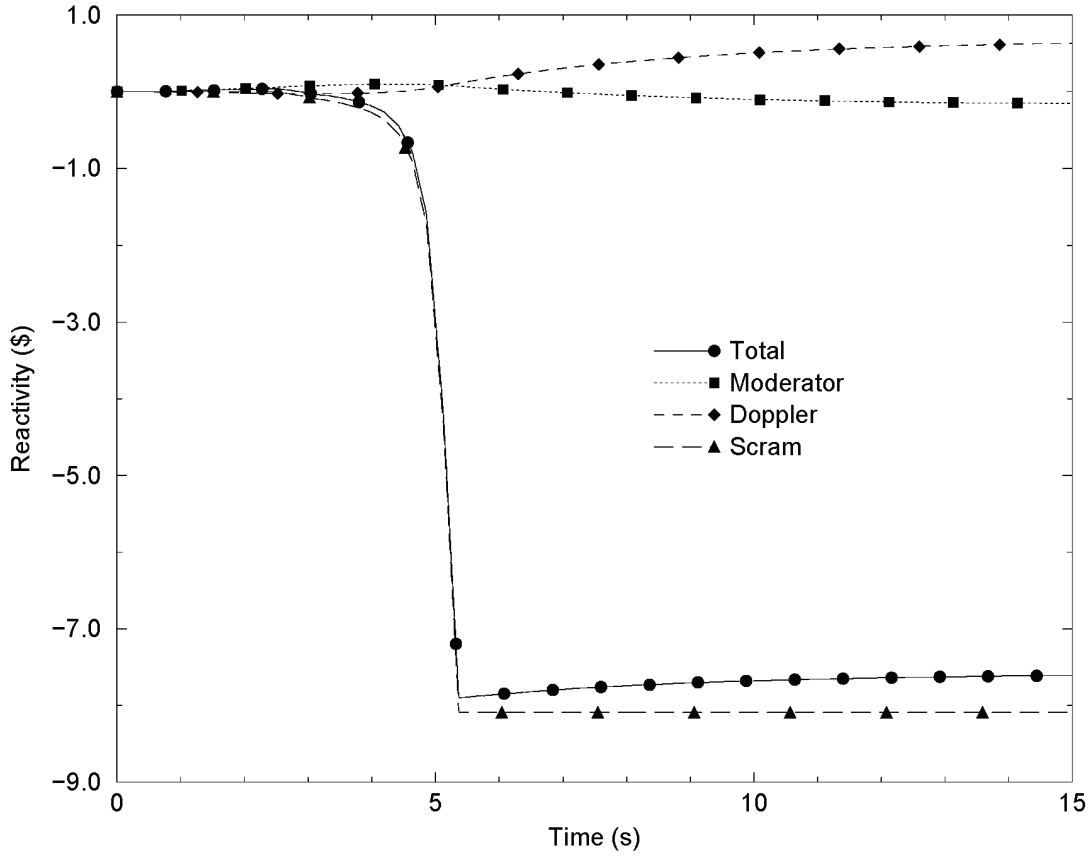

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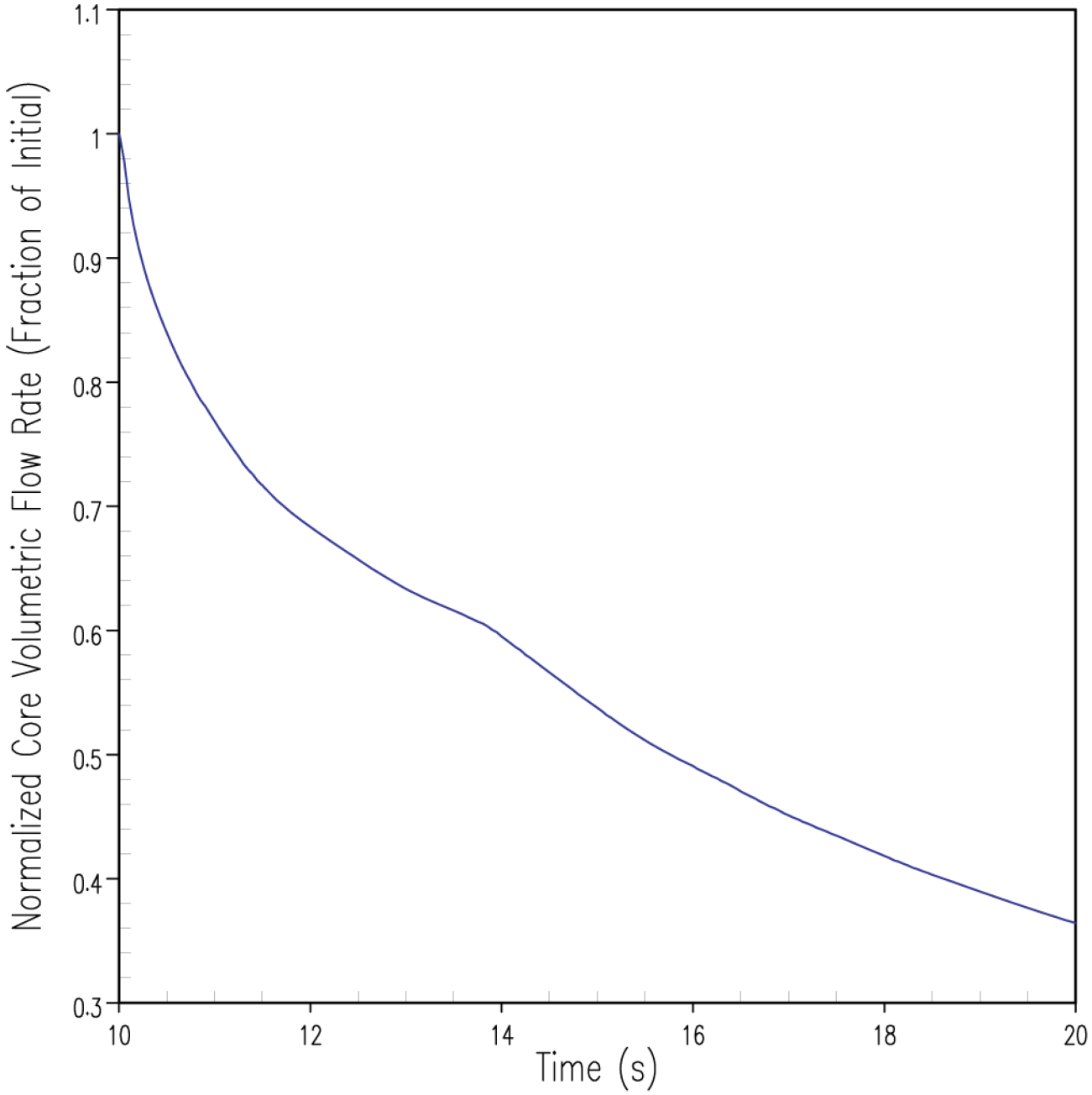
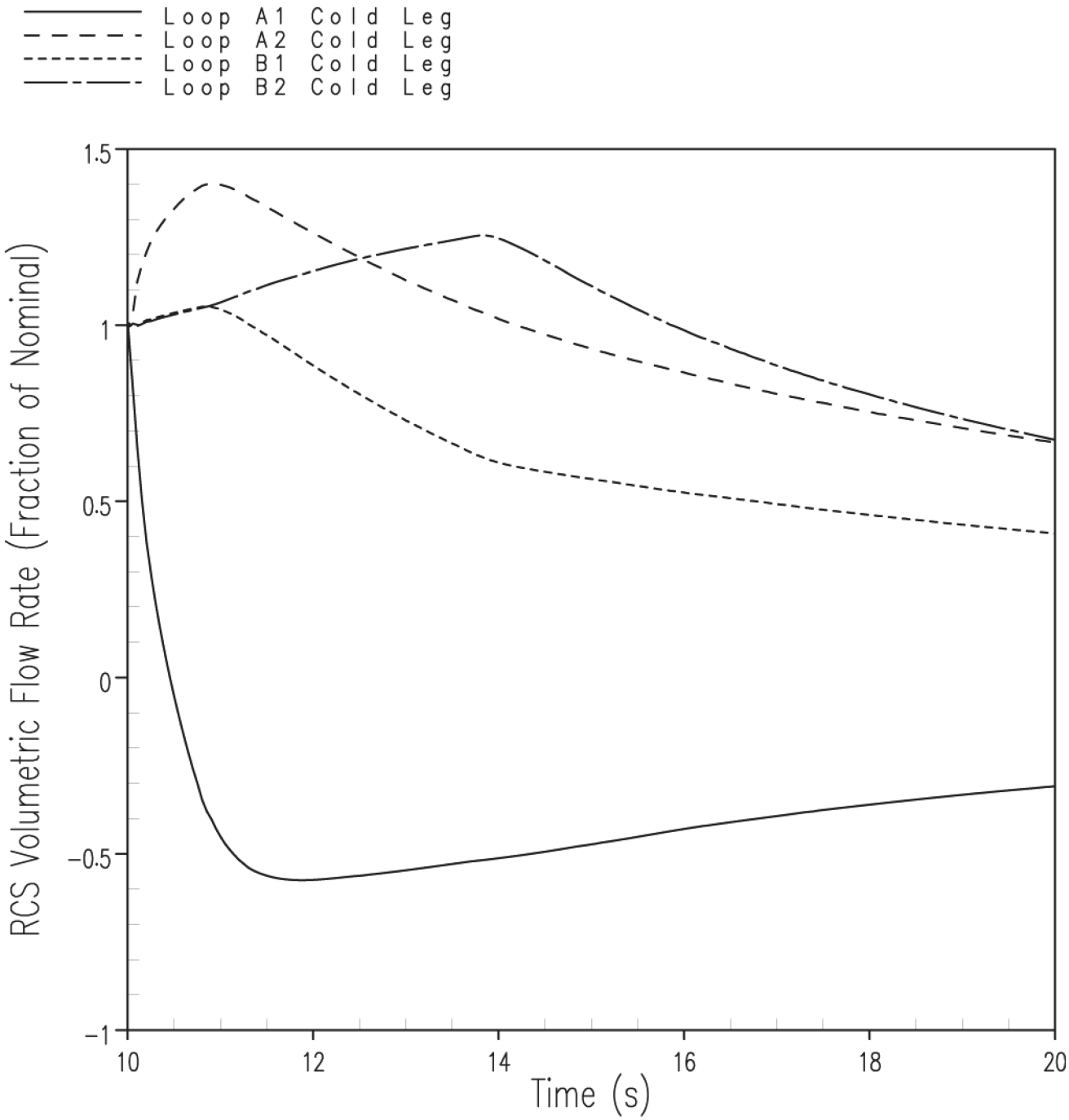
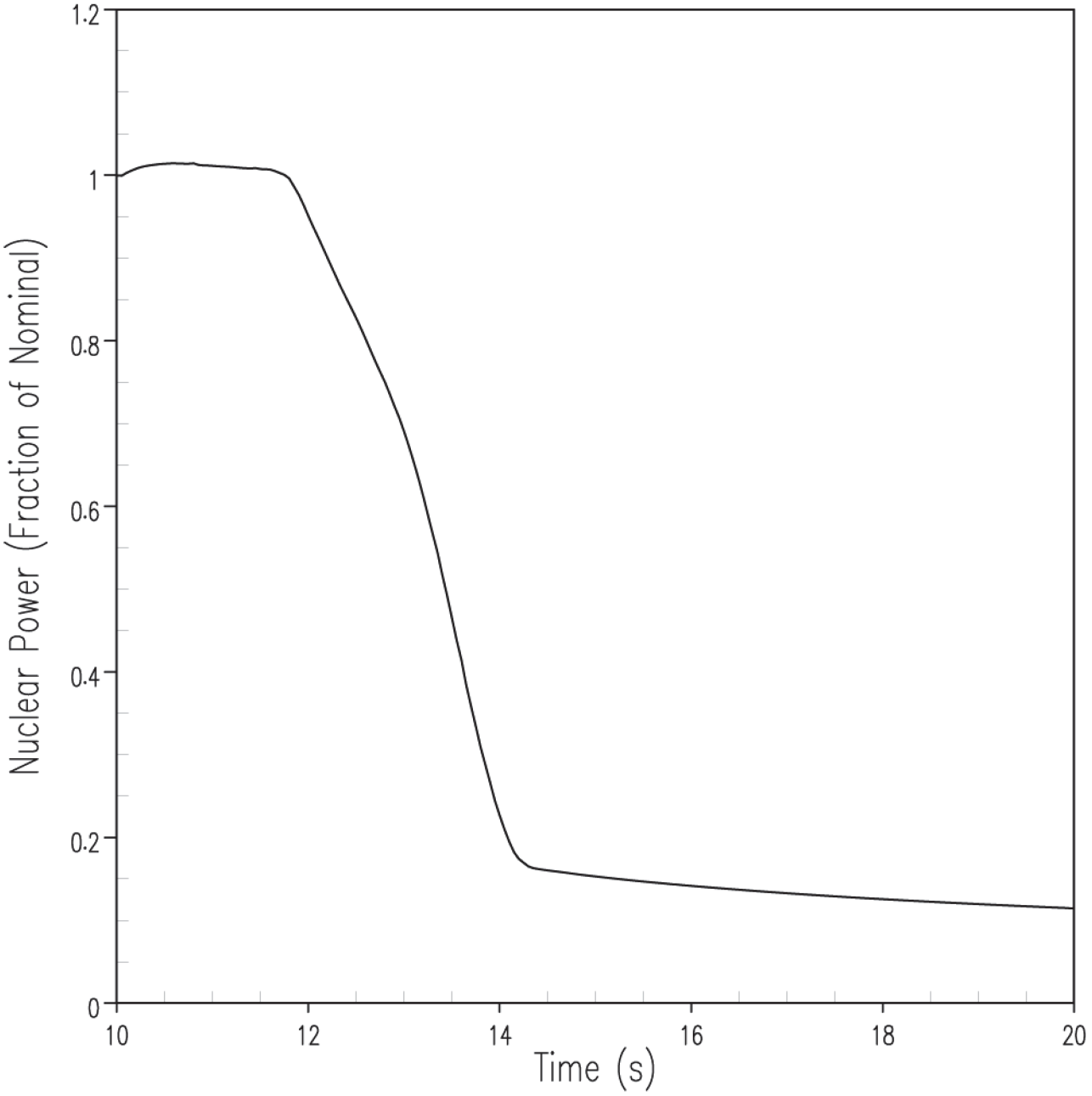
Figure 15.3.2-14
Complete Loss of Flow (AREVA):
Reactivity Feedback vs. Time



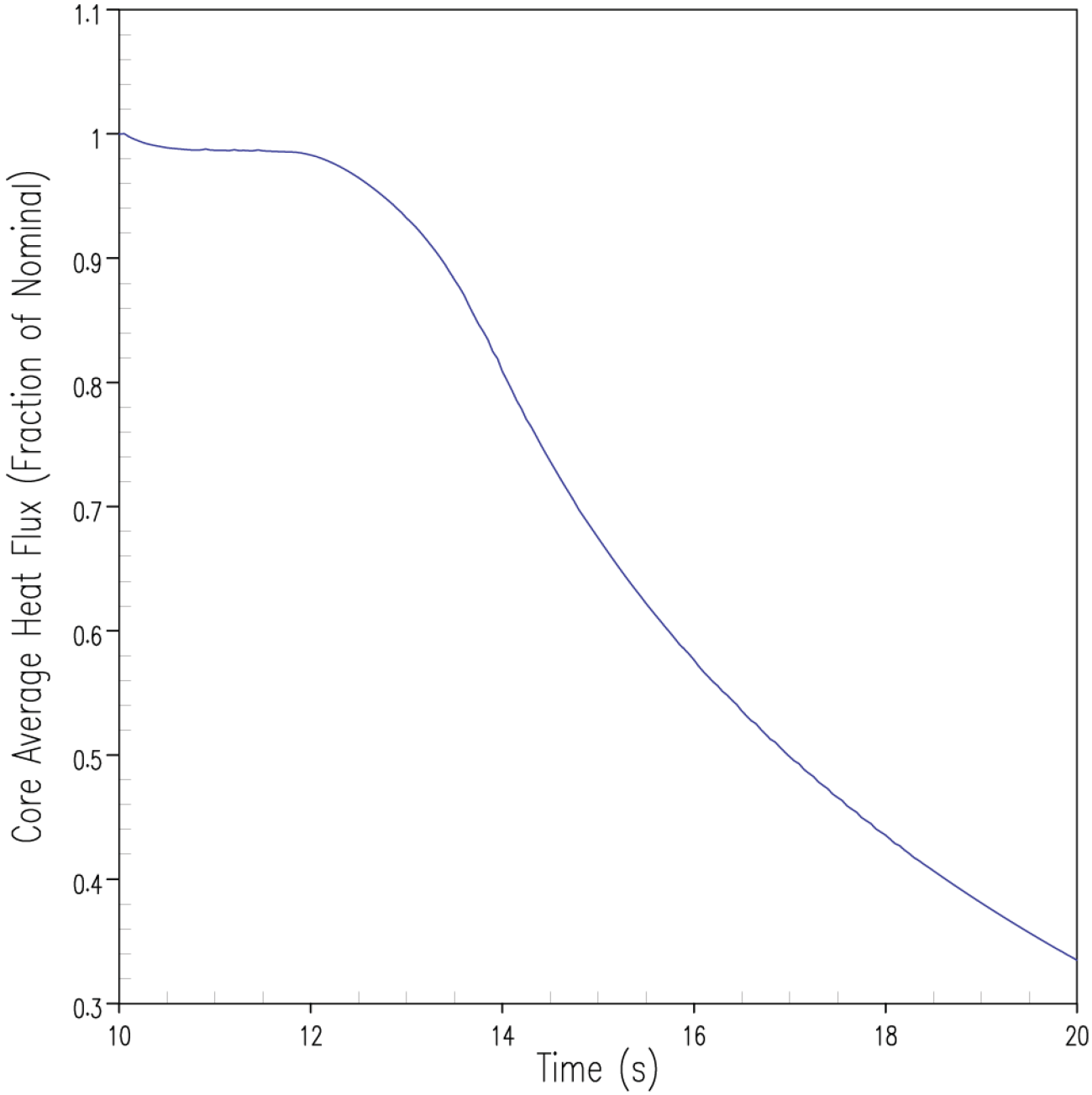
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-1 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case Normalized Core Volumetric Flow Rate versus Time



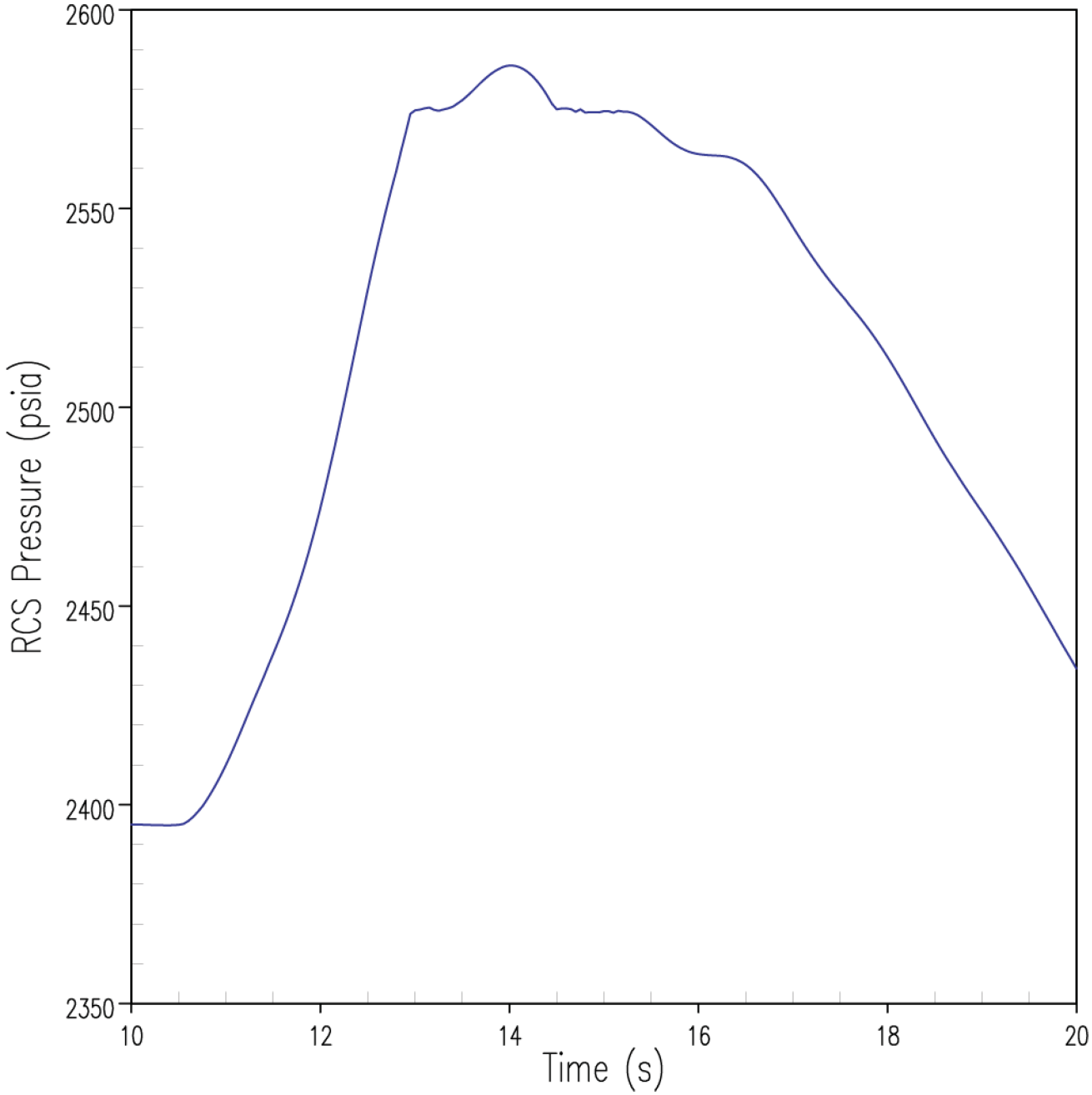
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-2 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case RCS Loop Flow versus Time



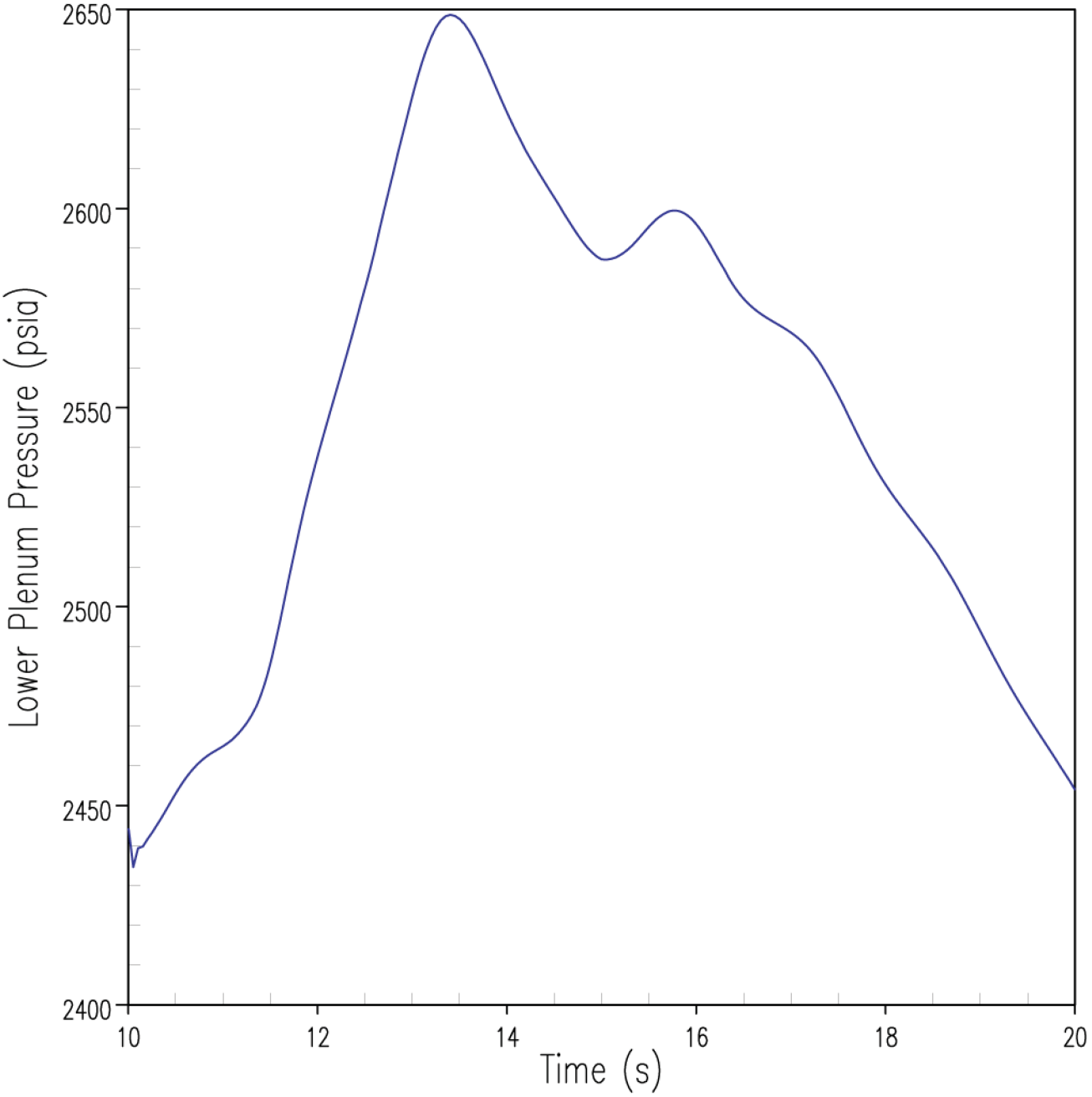
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-3 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case Nuclear Power versus Time



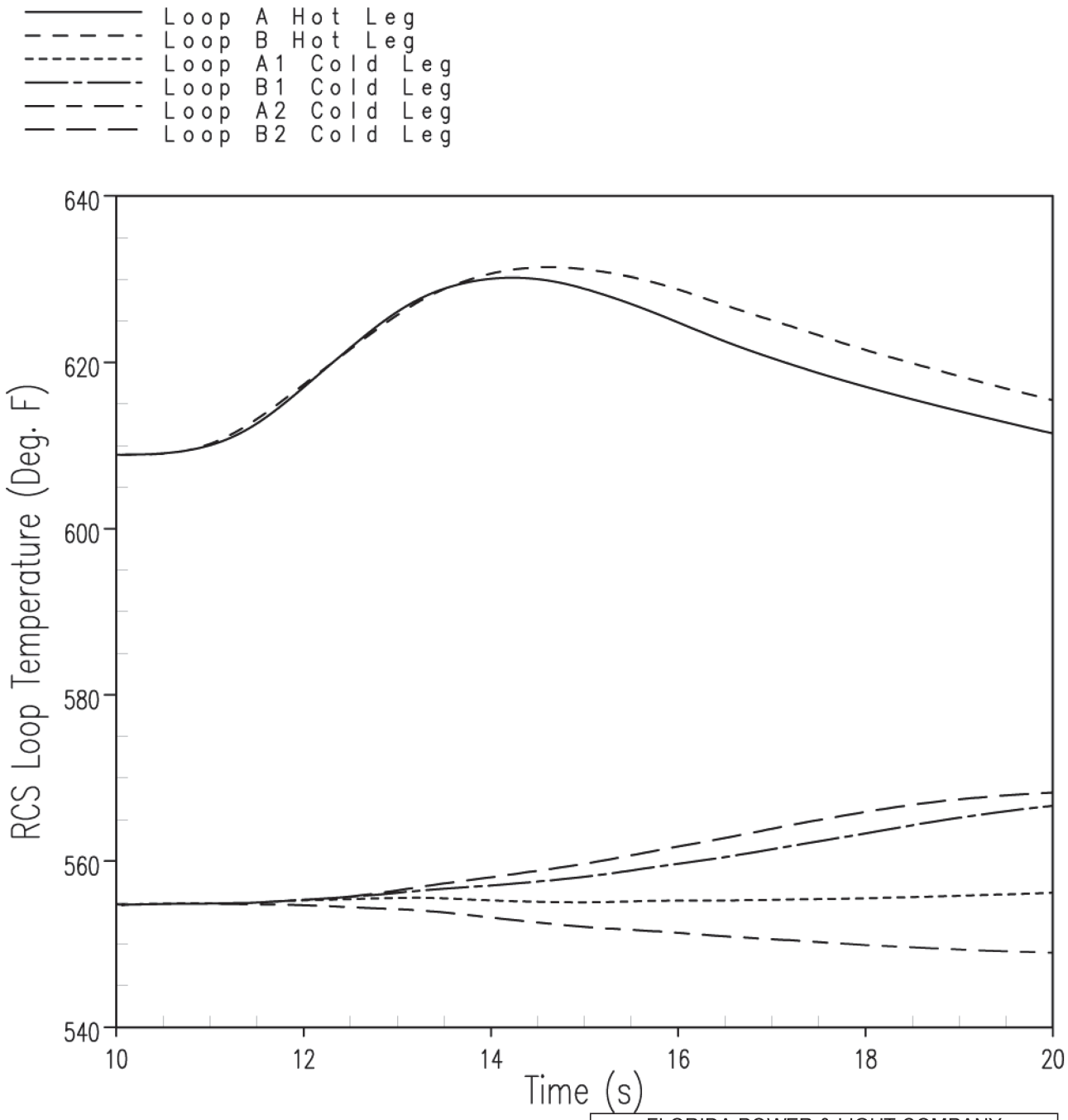
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-4 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case Core Average Heat Flux versus Time



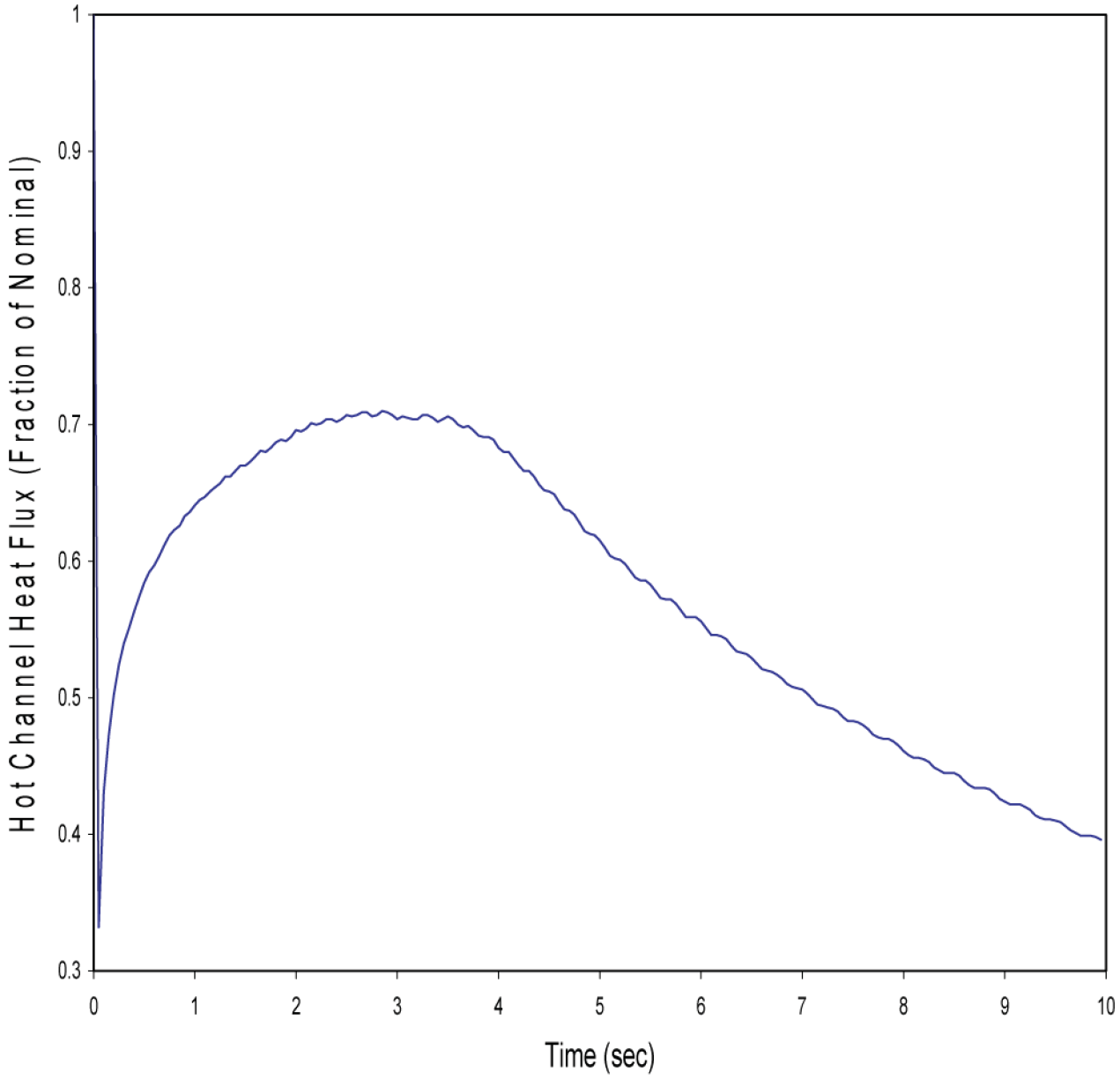
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-5 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case RCS Pressure (Pressurizer Pressure) versus Time



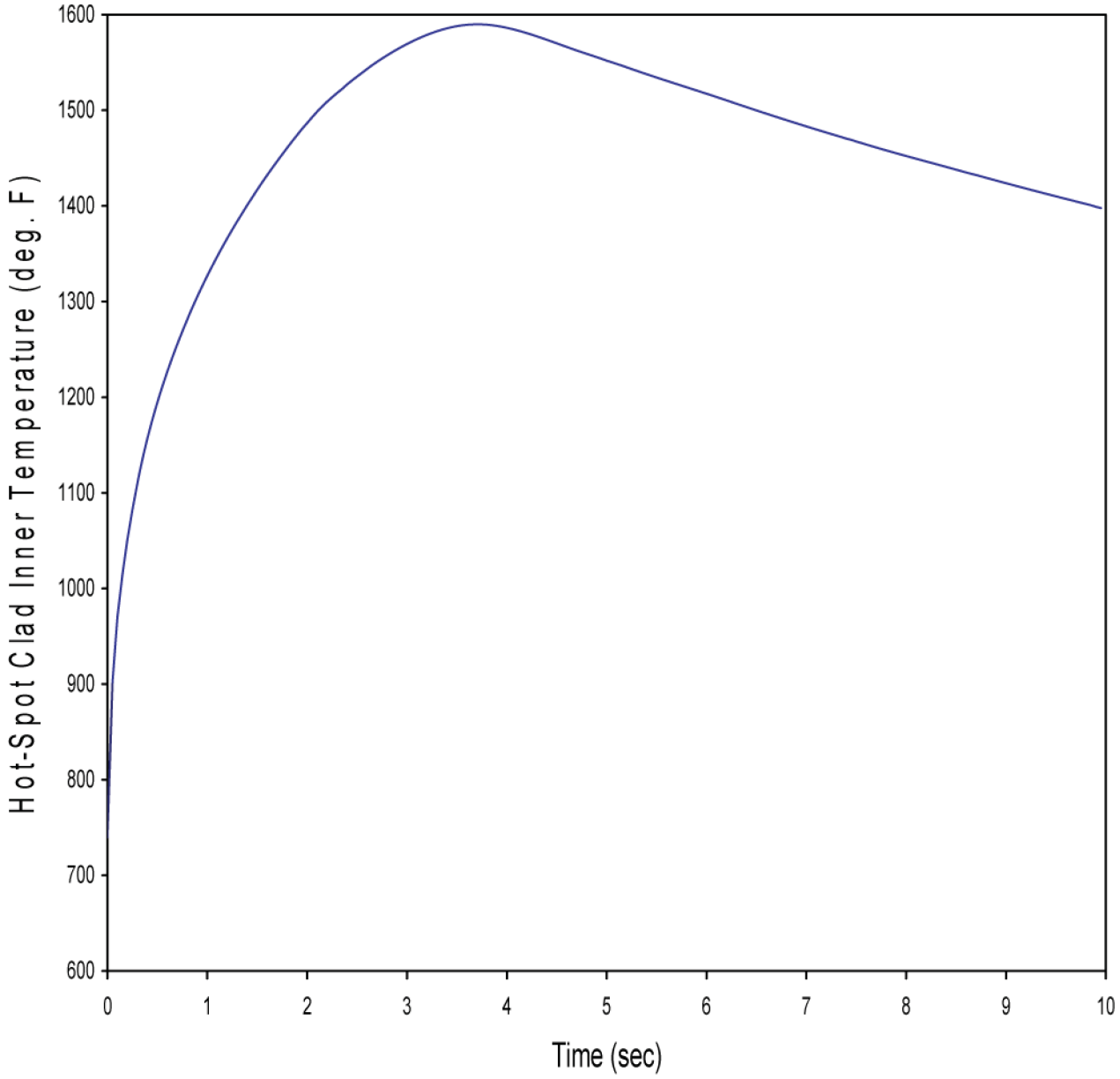
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-6 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case Peak RCS Pressure versus Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-7 Locked Rotor/Shaft Break with FFBT– RCS Pressure/Peak Cladding Temperature Case RCS Loop Temperature versus Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-8 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case Hot Channel Heat Flux versus Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.3.3-9 Locked Rotor/Shaft Break with FFBT – RCS Pressure/Peak Cladding Temperature Case Hot-Spot Cladding Inner Temperature versus Time

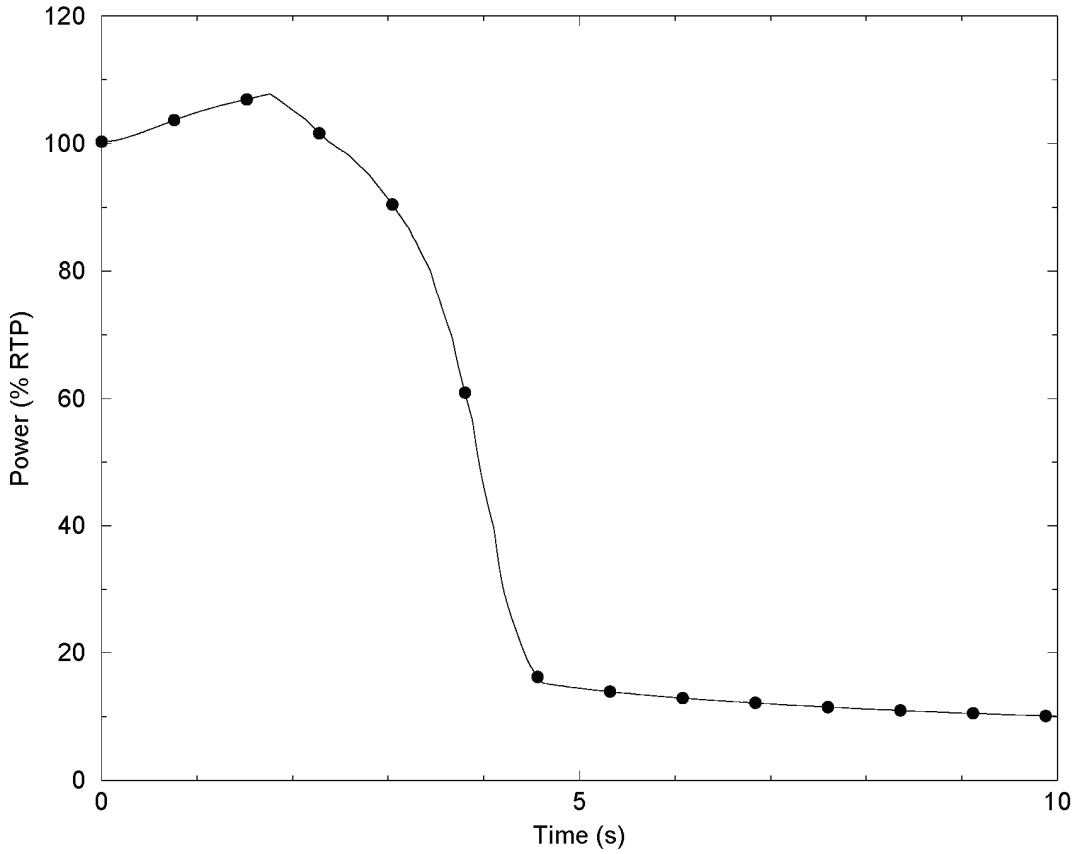


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Figure 15.3.3-10
Locked Rotor / Shaft Break (AREVA DNB):
Reactor Power vs. Time

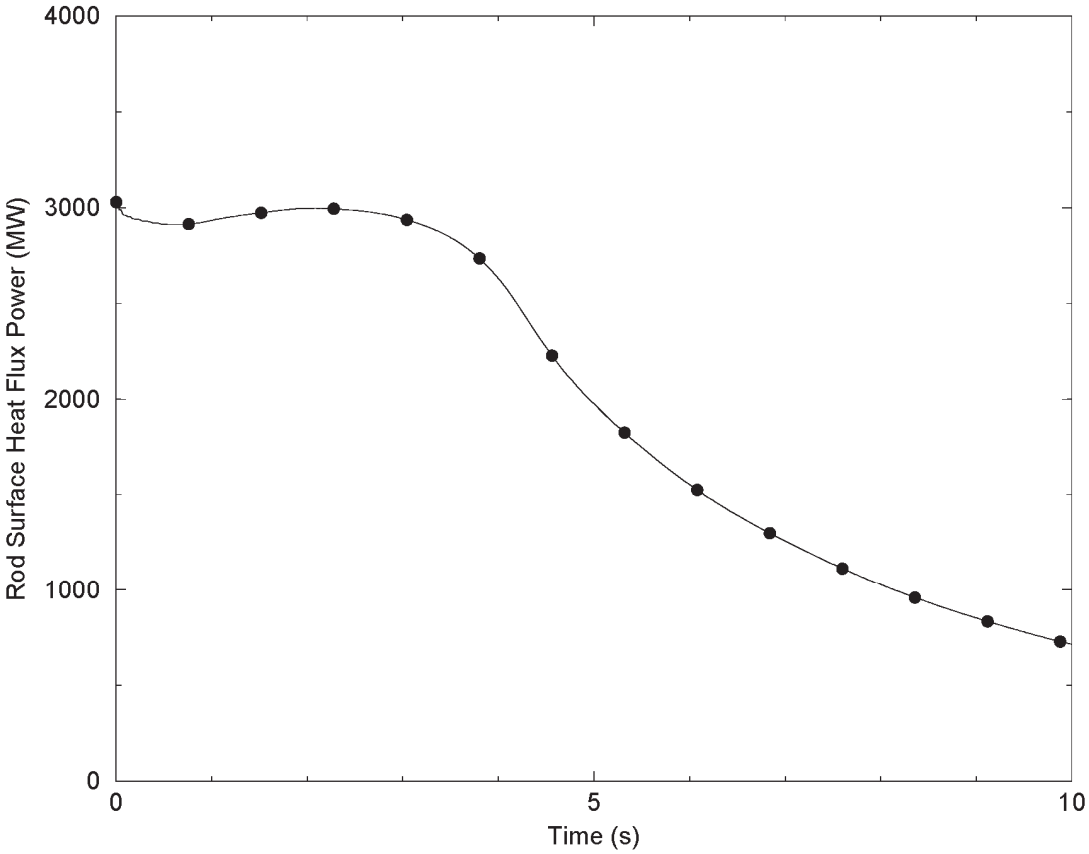

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Figure 15.3.3-11
Locked Rotor / Shaft Break (AREVA DNB):
Total Core Heat Flux Power vs. Time

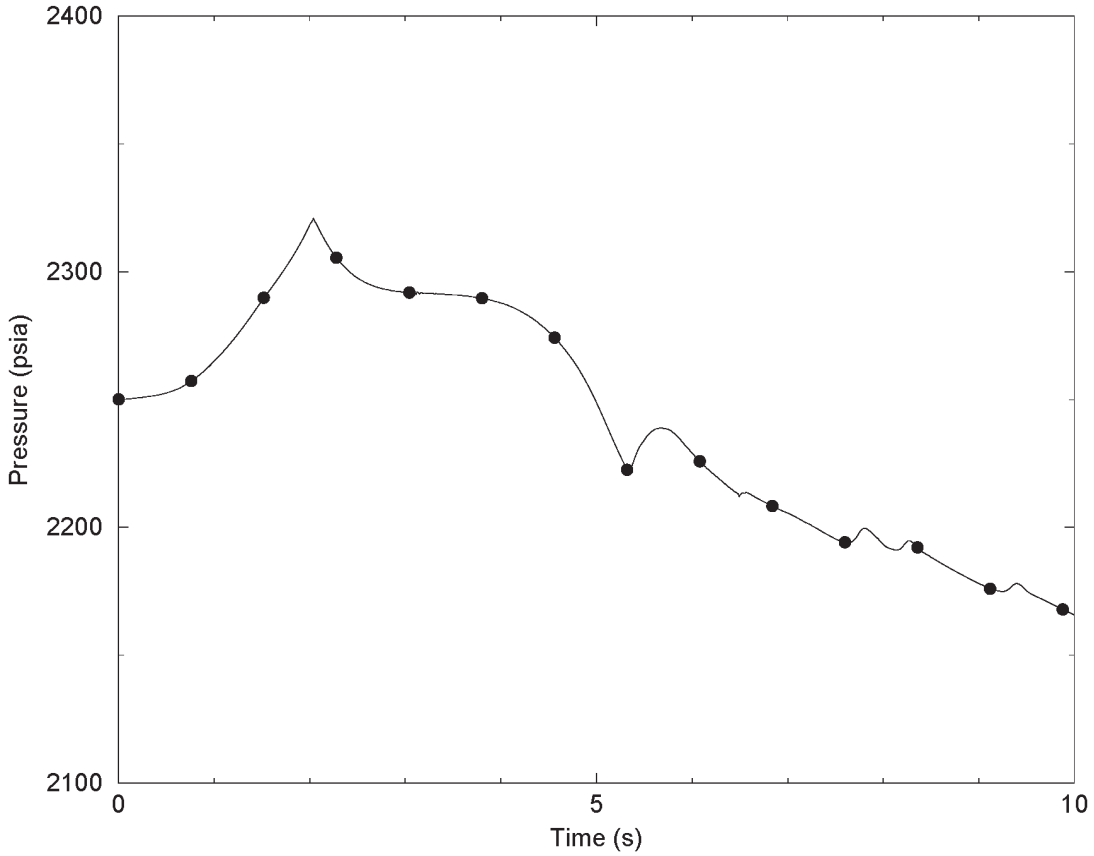

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Figure 15.3.3-12
Locked Rotor / Shaft Break (AREVA DNB):
Pressurizer Pressure vs. Time

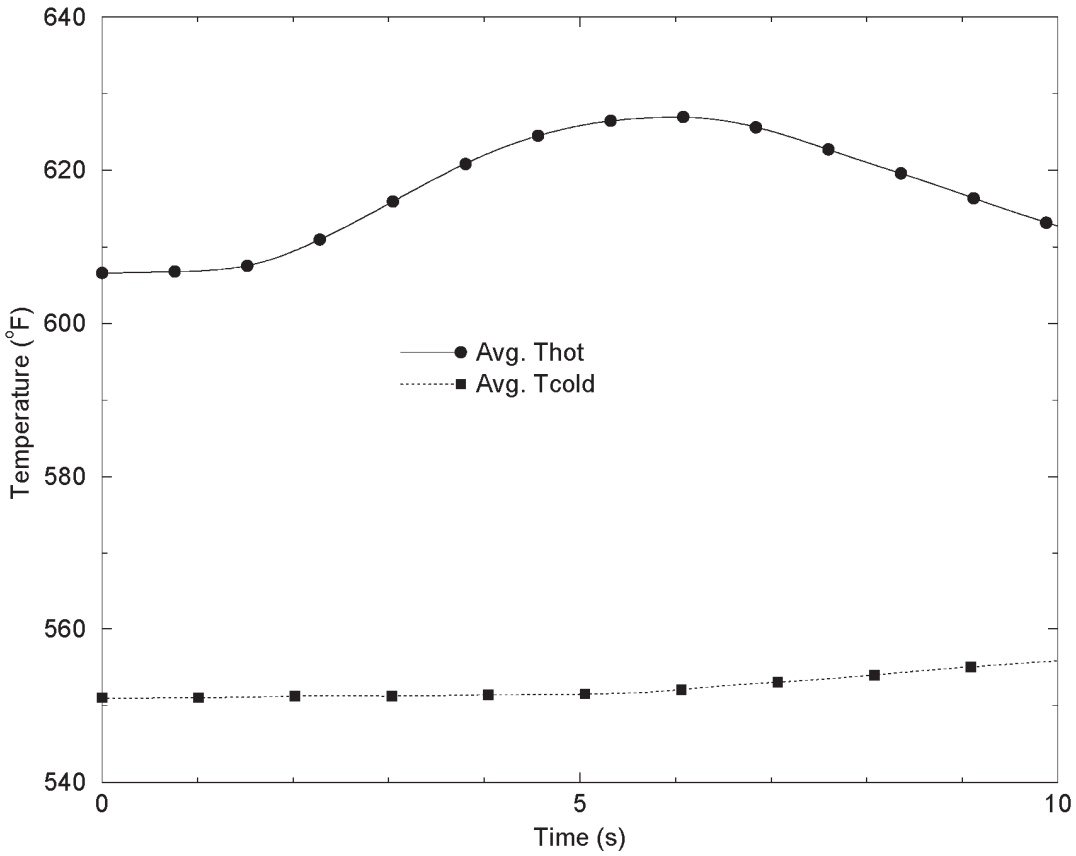

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Figure 15.3.3-13
Locked Rotor / Shaft Break (AREVA DNB):
RCS Loop Temperatures vs. Time

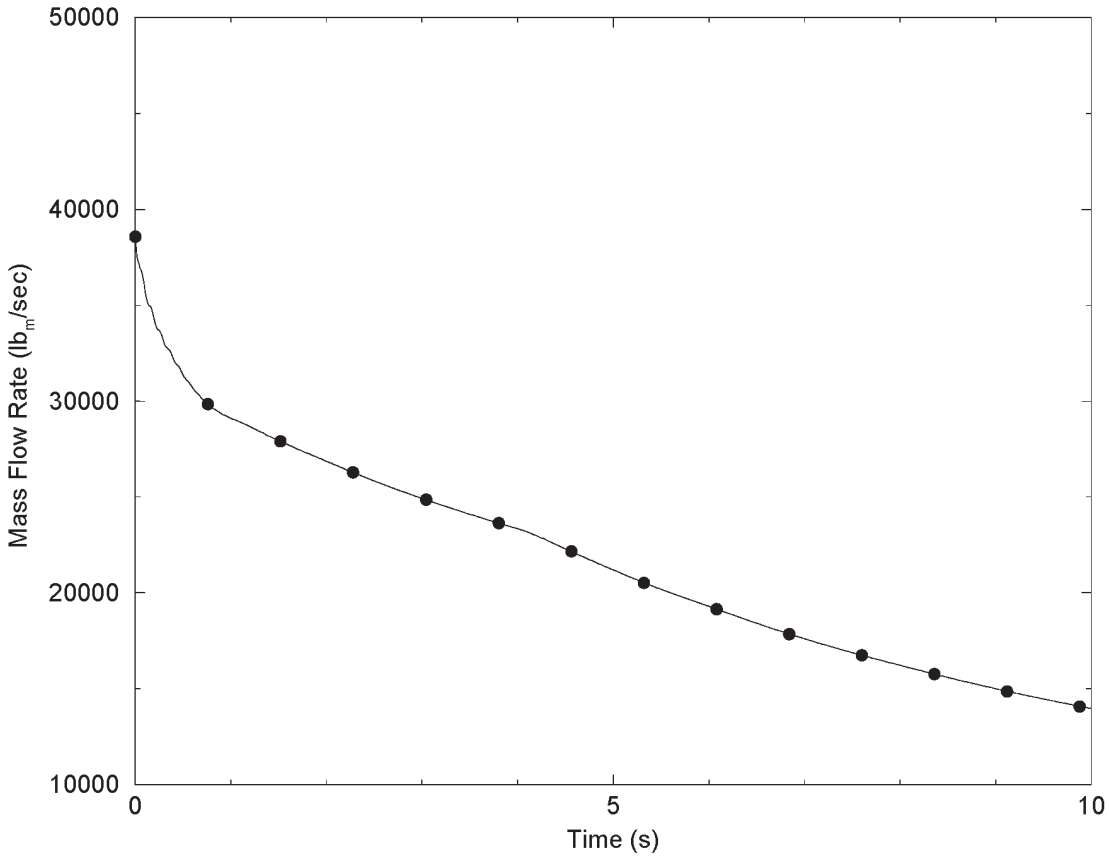

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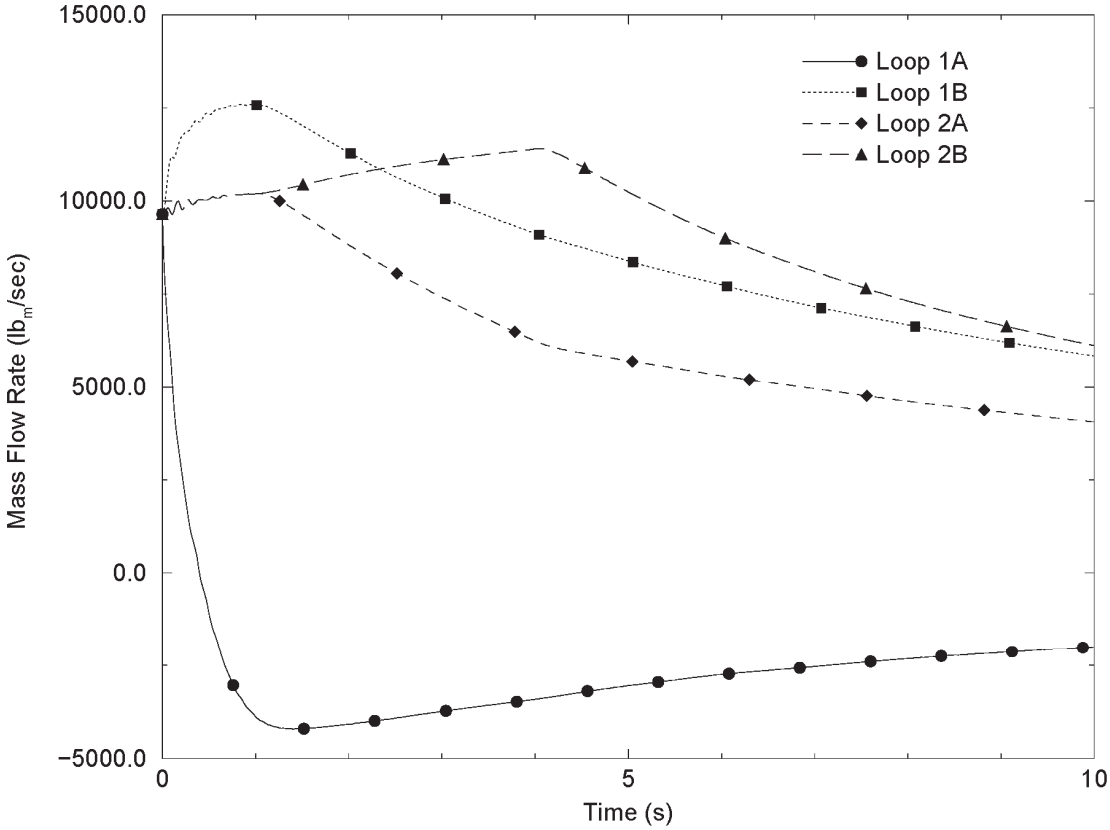
Figure 15.3.3-14
Locked Rotor / Shaft Break (AREVA DNB):
RCS Total Loop Flow Rate vs. Time



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Note: Loop 1A has the reactor coolant pump with the seized rotor.

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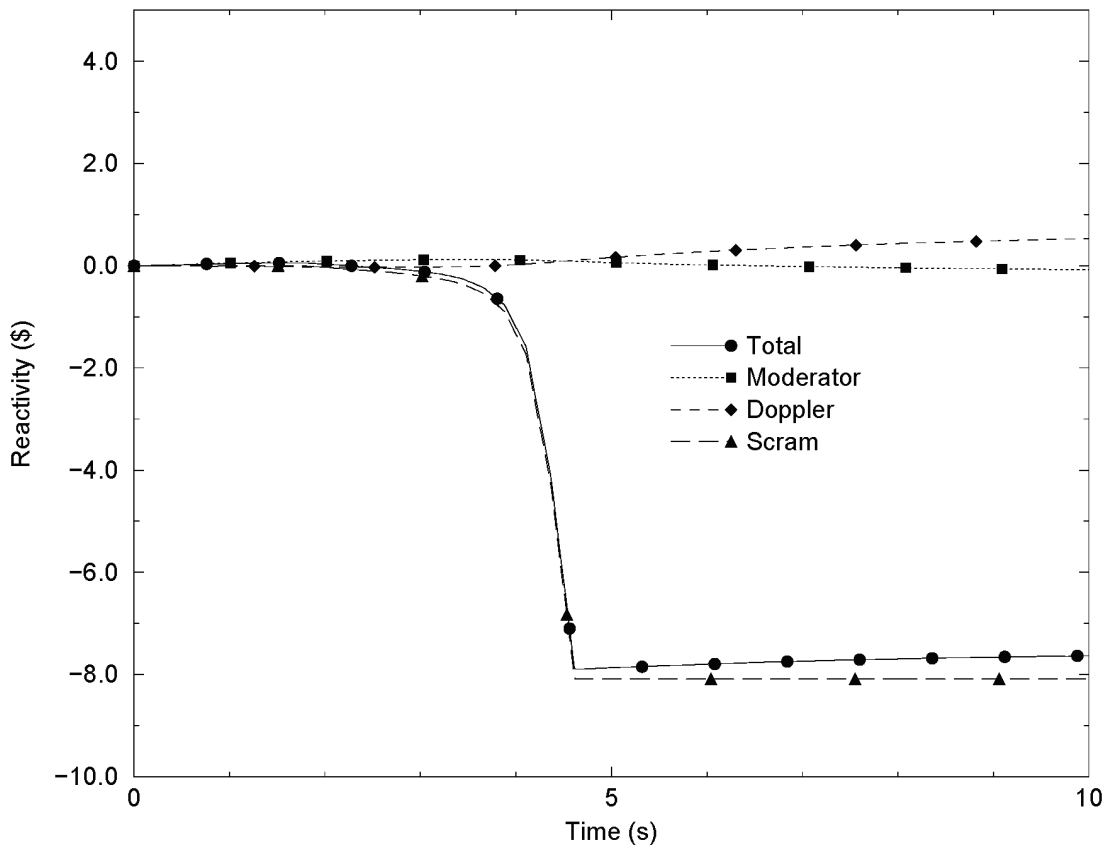
ST. LUCIE PLANT UNIT 2

Figure 15.3.3-15
Locked Rotor / Shaft Break (AREVA DNB):
RCS Loop Flow Rates vs. Time



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ST. LUCIE PLANT UNIT 2

Figure 15.3.3-16
Locked Rotor / Shaft Break (AREVA DNB):
Reactivity Feedback vs. Time

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

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

Discussions of the following events are presented in this section:

a. Uncontrolled control element assembly bank withdrawal from a subcritical or low power startup condition (Section 15.4.1)

b. Uncontrolled control element assembly bank withdrawal at power (Section 15.4.2)

c. Control element assembly misoperation (Section 15.4.3)

d. Startup of an inactive reactor coolant pump at an incorrect temperature (Section 15.4.4)

e. A malfunction or failure of the flow controller in a BWR recirculation loop that results in an increased reactor coolant flow rate (Section 15.4.5 - not applicable to St. Lucie Unit 2)

f. Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant (Section 15.4.6)

g. Inadvertent loading and operation of a fuel assembly in an improper position (Section 15.4.7)

h. Spectrum of control element assembly ejection accidents (Section 15.4.8)

Items (a), (b), (d), (e), and (f) are considered to be ANS Condition II events. Item (h) is an ANS Condition IV event. Item (c) entails both Conditions II and III events. Item (g) is considered to be an ANS Condition III event. Section 15.0.6 contains a discussion of ANS classifications.

15.4.1 UNCONTROLLED CONTROL ELEMENT ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL OR LOW POWER STARTUP CONDITION

15.4.1.1 Accident Description

The Control Element Assembly (CEA) withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of CEA banks resulting in a power excursion. While the occurrence of a transient of this type is unlikely, such a transient could be caused by a malfunction of the reactor control or the control element drive system. This could occur with the reactor either subcritical, at hot zero power (HZP), or at power. The "at power" case is discussed in Section 15.4.2.

Withdrawal of a CEA bank adds reactivity at a prescribed and controlled rate to bring the reactor from a subcritical condition to a low power level during startup. Although the initial startup

procedure typically uses the method of boron dilution, the normal startup is with CEA bank withdrawal. A CEA bank movement can cause much faster changes in reactivity than can be made by changing boron concentration (see Section 15.4.6, Chemical and Volume Control System Malfunction).

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self- limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous control element assembly withdrawal event occur, the following automatic features of the reactor protection system are available to terminate the transient:

- Variable Power Level Trip
- Rate-of-Change of Power Trip

Setpoints assumed and trip functions are summarized in Table 15.0-29.

15.4.1.2 Method of Analysis

The analysis of the uncontrolled CEA bank withdrawal from subcritical accident is performed in three stages. First, the spatial neutron kinetics computer code TWINKLE (Reference 15.4-1) is used to calculate the core average nuclear power transient including the various core feedback effects; that is, Doppler and moderator reactivity. FACTRAN (Reference 15.4-2) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the average heat flux and temperature transients. Finally, the peak core-average heat flux calculated by FACTRAN is used in VIPRE (see Section 15.0.14.5) for transient Departure from Nucleate Boiling Ratio (DNBR) calculations.

In order to give conservative results for a startup accident, the following assumptions are made:

1. Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler power defect, a conservatively low (absolute magnitude) value is used.

2. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and the moderator is much longer than the neutron flux response time constant. However, after the initial neutron flux peak, the moderator temperature coefficient (MTC) can affect the succeeding rate of power increase. The effect of moderator temperature changes on the rate of nuclear power increase is calculated in TWINKLE based on temperature-dependent moderator cross-sections.

3. The analysis assumes the reactor to be at HZP nominal temperature. This assumption is more conservative than that of a lower initial system temperature (that is, shutdown conditions). The higher initial system temperature yields a larger fuel-to-water heat transfer coefficient, a larger specific heat of the water and fuel, and a less negative (smaller absolute magnitude) Doppler Power Coefficient (DPC). The less negative DPC reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel-specific heat and larger heat transfer coefficient yields a larger peak heat flux. The analysis assumes

the initial effective multiplication factor (k_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

4. Reactor trip is initiated by the Variable High Power trip at a conservative trip setpoint of 35 percent. This increase from the nominal setpoint of 15 percent accounts for uncertainties. Figure 15.4.1-1 shows that the rise in nuclear power is so rapid that the effect of error in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position. Further, the delays for trip signal actuation and CEA release are accounted for in the analysis.

5. A very conservative maximum positive reactivity insertion rate of 53 pcm/sec was assumed, which is greater than that for the simultaneous withdrawal of the two sequential CEA banks having the greatest combined worth at the maximum speed (30 in/min). This is confirmed for each reload cycle.

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

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

8. The accident analysis does not use RTDP methodology. The reactor coolant system (RCS) flow rate will be based on the Thermal Design Flow (TDF) and that the RCS pressure is the nominal pressure minus the uncertainty. Since the event is analyzed from HZP, the steady-state uncertainties on core power and RCS average temperature are not used in defining the initial conditions.

9. The fuel rod heat transfer calculations performed to determine the maximum fuel temperature during this event assume a total peaking factor or hot channel factor, Fq, that is a function of the axial and radial power distributions.

10. Both UO_2 -only fuel and fuel with up to 8 weight percent (w/o) Gadolinia content were considered in the transient analysis.

AREVA Analysis

The analysis was performed with the approved non-LOCA methodology given in Reference 15.4-10. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), maximum fuel centerline temperature, and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.4-11), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.4-12). EC287528

Key input parameters and their values used in the analysis of this event were consistent with, or conservative relative to, the approved Reference 15.4-10 methodology. See Table 15.0-27 for key input parameter values.

- Initial Conditions – HZP initial conditions, maximum HZP core inlet temperature, and TS minimum RCS flow rate (for four-pump operation) were assumed, in order to maximize the challenge to DNB.

- Reactivity Feedback – Because this event involves a rapid increase in reactor power, the Doppler reactivity feedback is a key parameter. BOC Doppler reactivity feedback was assumed to minimize the negative reactivity resulting from the heatup of the fuel during the event. The TS maximum MTC at HZP was assumed. The scram worth was conservatively set to the TS minimum shutdown margin.

- Reactor Protection System Trips and Delays – The reactor protection system trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, a maximum CEA holding coil release delay was assumed. For conservatism, the High Rate-of-Change of Power trip was not credited in the analysis, except to the extent that it was used as justification for not initiating this event from subcritical modes of operation. EC287528

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and PORVs) parameters and equipment states were selected to reduce the primary system pressure, which provided a conservative calculation of the MDNBR during the transient.

- CEA Withdrawal Characteristics – To maximize the reactivity insertion from the CEA withdrawal, a bounding differential worth was assumed, together with a maximum CEA withdrawal speed. The reactivity insertion rate used for this event bounds the reactivity insertion rate corresponding to a Boron Dilution event.

- Gap Conductance – Gap conductance was set to a conservative BOC value, consistent with the time-in-cycle for the reactivity coefficients, to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback.

15.4.1.3 Results

Figures 15.4.1-1 through 15.4.1-3 show the transient behavior for a reactivity insertion rate of 53 pcm/sec, with the accident terminated by the reactor trip at 35 percent of nominal power. The rate is greater than that calculated for the two highest worth sequential control banks, with both assumed to be in their highest incremental worth region.

Figure 15.4.1-1 shows the core response transient. The core response overshoots the full power nominal value for a very short period of time. Therefore, the energy release and fuel temperature increase are relatively small. The heat flux response of interest for the DNB considerations is shown in Figure 15.4.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux of much less than the nominal full power value. Figure 15.4.1-3 shows the transient response of the hot spot fuel centerline, fuel average, and cladding temperatures. DNBR calculations indicate that the minimum DNBR remains above the safety analysis limit value at all times.

Table 15.4.1-1 presents the calculated sequence of events. After reactor trip, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal shutdown procedures.

AREVA Analysis

The sequence of events is given in Table 15.4.1-2

The transient response is shown in Figure 15.4.1-4 through Figure 15.4.1-8. Figure 15.4.1-4 shows the total reactivity feedback and its components, as functions of time. Figure 15.4.1-5 shows the reactor power and the core power based on rod surface heat flux. Figure 15.4.1-6 shows the fuel hot spot centerline temperature. Figure 15.4.1-7 shows the reactor coolant loop temperatures. Figure 15.4.1-8 shows the pressurizer pressure. EC287528

The results with respect to acceptance criteria are shown in Table 15.4.1-3. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation. The peak fuel centerline temperature was calculated to be less than the fuel centerline melt temperature.

15.4.1.4 Conclusions

In the event of a CEA withdrawal accident from the subcritical condition, the core and the RCS are not adversely affected since the combination of thermal power and coolant temperature result in a DNBR greater than the limit value. Therefore, no fuel or cladding damage is predicted as a result of this transient. In addition, the RCS pressure will not approach the limit since the total amount of excess energy deposited in the reactor coolant is relatively small and there is no prolonged power mismatch between the primary and secondary side that could cause a significant RCS pressure increase. In addition, any insurge during this event would not be nearly as severe as for the Loss of Condenser Vacuum/Turbine Trip event. Therefore, all acceptance criteria for this event are met.

15.4.2 UNCONTROLLED CONTROL ELEMENT ASSEMBLY BANK WITHDRAWAL AT POWER

15.4.2.1 Accident Description

The uncontrolled control element assembly (CEA) withdrawal at power event is defined as the inadvertent addition of reactivity to the core caused by the withdrawal of CEA banks when the core is above the no-load condition. The reactivity insertion resulting from the bank (or banks) withdrawal will cause an increase in core nuclear power and a subsequent increase in core heat flux and RCS temperature. A CEA bank withdrawal can occur with the reactor subcritical, at HZP, or at power. The uncontrolled CEA bank withdrawal at power event is analyzed for Mode 1 (power operation). The uncontrolled CEA bank withdrawal from a subcritical or low-power condition is considered as an independent event in Section 15.4.1.

The CEA withdrawal at power event is simulated by modeling a constant reactivity insertion rate starting at time zero and continuing until an automatic reactor trip occurs or, for very low reactivity insertion rates, sufficient time has passed to credit a manual reactor trip. The analysis assumes a spectrum of possible reactivity insertion rates up to a maximum positive reactivity insertion rate greater than that occurring for the simultaneous withdrawal, at maximum speed, of two sequential CEA banks having the maximum differential rod worth.

The transient RCS response to the CEA bank withdrawal event is terminated by manual or automatic action to preclude the power mismatch and resultant temperature rise from resulting in DNB and/or fuel centerline melt. Additionally, the increase in RCS temperature caused by this

event will increase the RCS pressure and, if left unchecked, could challenge the integrity of the RCS pressure boundary or the main steam system (MSS) pressure boundary.

To avert the core damage that might otherwise result from this event, the reactor protection system (RPS) is designed to automatically terminate any such event before the DNBR falls below the limit value, the peak linear heat rate limit is reached, or the peak primary and secondary pressures exceed their respective limits. Depending on the initial power level and the reactivity insertion rate, the reactor may be tripped and the CEA withdrawal terminated by any of the following trip signals:

- Variable High Power (VHP)
- High Pressurizer Pressure
- Thermal Margin/Low Pressure
- High Local Power Density

15.4.2.2 Method of Analysis

The uncontrolled CEA bank withdrawal at power event is analyzed to show that: (1) the integrity of the core is maintained by the RPS because the DNBR and peak linear heat rate remain within the safety analysis limit values and (2) the peak RCS and MS system pressures remain below 110 percent of the corresponding design limits. Of these criteria, the most limiting are the need to ensure that the DNBR and peak linear heat rate limits are met.

The CEA bank withdrawal at power transient is analyzed with the RETRAN computer program (References 15.4-4 and 15.4-5). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator relief and safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Selected initial conditions used in the safety analysis are summarized in Table 15.0-27. To obtain conservative values for minimum DNBR and ensure that the peak kW/ft limits are met, the following analysis assumptions are made:

1. Cases analyzed to assess the acceptability with respect to DNBR limits are analyzed with the RTDP DNB methodology (Reference 15.4-6). Therefore, initial reactor power, RCS pressure, RCS flow and RCS temperatures are assumed to be at their nominal values. Uncertainties in these initial conditions are included in the DNBR limit. Minimum measured Flow is modeled.

2. Reactivity coefficients - Two feedback conditions are analyzed:

    a. Minimum reactivity feedback - A zero MTC of reactivity (0 pcm/°F) is assumed at full power. For power levels less than or equal to 70-percent power, a positive MTC of reactivity (+5 pcm/°F) is conservatively assumed, corresponding to the beginning of core life. A conservatively small (in absolute magnitude) Doppler power coefficient is used in the analysis (see Figure 15.0-4).

b. Maximum reactivity feedback - A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed (Figure 15.0-4).

3. The variable high power reactor trip on high neutron flux or high indicated power from temperature measurement (ΔT-power) is actuated at a conservative safety analysis ceiling value of 112.2 percent of nominal full power. The decalibration of the excore detectors is conservatively modeled as the CEAs are withdrawn to account for the effect of the reduced indicated excore detector power which delays the reactor trip on the neutron flux signal.

4. A conservative safety analysis variable high power trip (VHPT) offset setpoint of 12% of rated thermal power (RTP) at 100% power and 14% of RTP at part power conditions are modeled. For part power RCS overpressure cases, a VHPT offset setpoint of 12% RTP is assumed for the 50% of full power and greater cases. The 25% of full power case is analyzed with a VHPT offset setpoint of 14% RTP. These setpoints include both power measurement and process uncertainties.

5. In all cases, the thermal margin/low pressure trip is modeled without taking credit for any reduction in the calculated trip setpoint pressure associated with any skewed axial shape index (ASI). Two different approaches are employed with regard to the indicated core power signal that is used by the thermal margin/low pressure function. The initial power level dictates the approach selected for any particular case.

   a. For the cases initiated from less than full power (20, 50 and 65 percent of nominal full power) excore decalibration due to CEA withdrawal was not modeled. No such modeling was required because all of these cases produced an earlier reactor trip on signals other than the thermal margin/low pressure trip function.

   b. For cases initiated from 100 percent power, the highest of the excore or ΔT-power signals is used by the thermal margin /low pressure trip logic. The decalibration of the excore detectors is conservatively modeled as the CEAs are withdrawn to account for the effect of the reduced indicated excore detector power which delays the reactor trip on the neutron flux signal input to the TM/LP.

6. The high pressurizer pressure reactor trip setpoint assumed in the safety analysis is 2415 psia.

7. All of the reactor trip functions modeled in the CEA withdrawal at power analysis include appropriate instrumentation and setpoint errors. The delays for trip actuation are assumed to be the maximum values (see Table 15.0-29).

8. The CEA trip insertion characteristics are based on the assumption that the highest worth assembly is stuck in its fully withdrawn position (see Figure 15.0-6).

9. A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservative speed. The maximum bounding reactivity insertion rate

that is required for consideration is 53 pcm/sec. A minimum withdrawal rate of 1 pcm/sec is considered.

10. The analysis includes consideration of up to 10% steam generator tube plugging in both steam generators.

11. Power levels of 20, 50, 65 and 100 percent of full power are considered.

AREVA SAFDLs Analyses

The analyses were performed with the approved non-LOCA methodology given in Reference 15.4-10, as supplemented in Section 2.7 of Reference 15.4-13. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.4-11), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.4-12).

A spectrum of positive reactivity insertion rates is possible, from very slow to fast, limited only by bank worth and drive speed. Two reactivity feedback matrices of cases were analyzed: One for most-positive reactivity feedback (most-positive MTC and least-negative Doppler coefficient), and the other for most-negative feedback (most-negative MTC and most-negative Doppler coefficient). A range of initial reactor power levels was analyzed.

For both reactivity feedback matrices of cases, the reactivity insertion rates used bound the respective lowest MDNBR point and the maximum possible reactivity insertion rate: EC287528

Case	Range of Reactivity Insertion Rates (pcm/sec)	
	Minimum	Maximum
BOC, full power	0.001	14
EOC, full power	2.4	20
BOC, 90% RTP	0.001	16
EOC, 90% RTP	2.4	24
BOC, 65% RTP	0.001	26
EOC, 65% RTP	2.3	32
BOC, 20% RTP	0.011	38
EOC, 20% RTP	2.9	50

The lower bound of the reactivity insertion rates also bounds the reactivity insertion rate corresponding to a Mode 1 Boron Dilution event.

Key input parameters and their values used in the analyses of this event were consistent with, or conservative relative to, the approved Reference 15.4-10 methodology, as supplemented in Section 2.7 of Reference 15.4-13. See Table 15.0-27 for key input parameter values.

- Initial Conditions – Full power, 90% RTP, 65% RTP, and 20% RTP levels were evaluated, with maximum core inlet temperature and TS minimum RCS flow rate, in order to ensure that initial conditions most challenging to the SAFDLs were used.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. Both BOC and EOC kinetics were analyzed, to assess the impact of moderator and Doppler feedback. The MTCs were assumed to be either a value that bounds the TS most-positive limits for the BOC cases or a value that bounds the TS most-negative limit for the EOC cases. Doppler reactivity was biased to bound the range of feedback from BOC to EOC.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, control rod insertion was delayed to account for CEA holding coil release delay time.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and PORVs) parameters and equipment states were selected to reduce the primary system pressure, which provided a conservative calculation of the MDNBR during the transient. EC287528

- CEA Withdrawal Characteristics – As a conservative analytical assumption, withdrawal of the CEAs was not terminated at reactor trip. Decalibration of the NI power signal due to CEA shadowing as the CEAs are withdrawn was conservatively accounted for.

- Gap Conductances – The fuel-to-cladding gap conductances were set to conservative values that are consistent with the time-in-cycle for the reactivity coefficients and that account for the effects of fuel TCD.

15.4.2.3 Results

Selected results are reported in Table 15.4.2-1 for the CEA bank withdrawal at power transients analyzed to support the extended power uprate. The limiting results are summarized in Table 15.4.2-2.

For all of the cases analyzed, including reactivity insertion rates of up to 53 pcm/second, the RCS pressure never exceeds the 110% of design limit of 2750 psia. The reactivity insertion rate of 53 pcm/sec bounds that calculated for the simultaneous withdrawal, at maximum speed, of two sequential CEA banks having the maximum differential rod worth.

Figure 15.4.2-1 shows the response of nuclear power, pressurizer pressure, RCS vessel T_{avg}, and DNBR to a rapid (53 pcm/sec) CEA withdrawal incident starting from full power with minimum reactivity feedback conditions. Reactor trip on the variable high power function occurs shortly after the start of the accident. Since this case results in a rapid increase in the nuclear power with the core heat flux lagging behind because of the thermal time constants of the plant, small changes in the reactor core T_{avg} and pressurizer pressure result. Therefore, a large margin to the safety analysis limit DNBR is maintained.

The response of nuclear power, pressurizer pressure, RCS vessel T_{avg}, and DNBR for a slow (2 pcm/sec) CEA withdrawal from 100-percent power with maximum reactivity feedback conditions is shown in Figure 15.4.2-2. Reactor trip on the variable high power function occurs after a longer period of time compared to the rapid CEA withdrawal mentioned above and thus, the rise in temperature is consequently larger. Again, the minimum DNBR is greater than the safety analysis limit value.

Figure 15.4.2-3 shows the minimum predicted DNBR as a function of the reactivity insertion rate for the four initial power levels analyzed (100 percent, 65 percent, 50 percent and 20 percent) for both minimum and maximum reactivity feedback conditions. It can be seen that the combination of reactor trip functions modeled provides protection over the entire range of reactivity insertion rates because the minimum DNBR is never less than the safety analysis limit value. In the referenced figures, the shape of the curves of minimum DNBR versus reactivity insertion rate is a function of both the reactor core and coolant system transient response and the reactor trips assumed to provide protection for this event.

Referring to Figure 15.4.2-3 (Sheet 1) for example, it is noted that:

1. For the minimum reactivity cases initialized from 100% power, the reactor was tripped on either a High Pressurizer Pressure Trip or a Variable High Power Trip. Cases with low reactivity insertion rates were tripped on High Pressurizer Pressure, while large reactivity insertion rates were tripped on Variable High Power. For the variable high power trip cases, even with excore decalibration effects modeled, the variable high power reactor trip on the excore detector indicated power signal produces the reactor trip. For the full power minimum feedback cases over the entire range of reactivity insertion rates considered, the minimum predicted DNBR values remain well above the safety analysis limit value.

2. When modeling maximum reactivity feedback for cases initiated from 100% power, protection is provided by a combination of the thermal margin/low pressure and high pressurizer pressure trip functions. For the range of low reactivity insertion rates (from 1 to 5 pcm/sec), reactor trip occurs on the thermal margin/low pressure reactor trip. With these relatively low reactivity insertion rates and maximum reactivity feedback, the core power increase is limited. However, as the reactivity insertion continues, the RCS temperature rises until a thermal margin/low pressure reactor trip is generated. For larger insertion rates (10 - 53 pcm/sec) reactor trip occurs on the High Pressurizer Pressure. The minimum DNBR values predicted for all the maximum feedback cases for the entire range of reactivity insertions are all well above the safety analysis limit value.

AREVA SAFDLs Analyses

The DNB and peak LHR results are given in Table 15.4.2-4. The DNB SAFDL is most challenged at BOC full-power initial conditions. The peak LHR does not significantly challenge the LHR limit for this event.

The sequence of events for the DNB-limiting case (initiated from BOC full-power conditions, with a 0.08 pcm/sec reactivity insertion rate) is given in Table 15.4.2-3. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation. EC287528

The transient response for the DNB-limiting case is shown in Figure 15.4.2-4 through Figure 15.4.2-9. Figure 15.4.2-4 shows the reactor power as a function of time. Figure 15.4.2-5 shows the core power based on rod surface heat flux. Figure 15.4.2-6 through Figure 15.4.2-9 show the pressurizer pressure, pressurizer liquid level, RCS loop temperatures, and reactivity feedback, respectively.

15.4.2.4 Conclusions

The results for the uncontrolled CEA bank withdrawal at power transient demonstrate that the combination of the variable high power, thermal margin/low pressure, and high pressurizer pressure reactor trip functions provide adequate protection over the entire range of possible reactivity insertion rates, expected initial power levels and for different times in life. That is, the minimum calculated DNBR is always greater than the safety analysis limit value. In addition, it was demonstrated that the peak kW/ft is less than the limit value for fuel melting and that the peak pressures in the RCS and secondary steam system do not exceed 110 percent of their respective design pressures.

Thus, all pertinent safety analysis criteria are met for the uncontrolled CEA bank withdrawal at power event in support of the extended power uprate program.

15.4.3 CONTROL ELEMENT ASSEMBLY (CEA) MISOPERATION

15.4.3.1 Accident Description

A Control Element Assembly (CEA) Drop Event is a Condition II event that is assumed to be initiated by a single electrical or mechanical failure which causes any number and combination of rods from a CEA subgroup to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor may occur due to the skewed power distribution representative of a CEA drop configuration. Since this is a Condition II event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a CEA Drop Event.

The CEA Drop Event accident includes:

- Full-length CEA drop
- Full-length CEA subgroup drop

The St. Lucie Unit 2 CEA drop detection system is assumed inoperable with no credit taken for the turbine runback feature. With a decrease in reactor power, the turbine load is not reduced, but is assumed to remain the same prior to the dropped CEA. This results in a power mismatch between the primary and secondary system, which leads to a cooldown of the reactor coolant system. In addition, the automatic withdrawal capability of the Control Element Drive Mechanism is disabled. Following a CEA drop the plant will establish a new equilibrium condition at the original power level but at a reduced reactor coolant system temperature and pressure.

15.4.3.2 Method of Analysis

Full-length CEA Subgroup and Full-length CEA Drop

The transient following a CEA Drop Event is determined by a detailed digital simulation of the plant using the RETRAN code as described in References 15.4-4 and 15.4-5. The RETRAN code is a digital computer code, developed to simulate transient behavior in light water reactor systems. This program includes point kinetics and one-dimensional kinetics model, one-dimensional homogenous equilibrium mixture thermal-hydraulic model, control system models,

two-phase natural convection heat transfer correlation, a non-equilibrium pressurizer model, etc. The code computes pertinent plant variables including temperatures, pressures, and power levels. Since RETRAN employs a point kinetics model, a CEA drop is modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped CEA regardless of the configuration of the CEA(s) that drop. The system transient is calculated by assuming a constant turbine load demand at the initial value (no turbine runback) and no bank withdrawal. A spectrum of dropped CEA worths from 100 pcm to 1000 pcm was analyzed.

Transient conditions are calculated that are then analyzed with nuclear models to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met.

AREVA Analyses

Detailed analyses were performed with the approved non-LOCA methodology given in Reference 15.4-10. For this event, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.4-11), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.4-12).

Calculations were performed at EOC full-power conditions, TS maximum core inlet temperature, and TS minimum RCS flow rate. This produces the minimum margin to the DNB limit. The event was analyzed with the most-negative MTC limit, which results in the most-positive moderator reactivity feedback as the RCS cools down, due to the dropped CEA. EC287528

A range of dropped CEA worths from 25 to 1000 pcm was analyzed, to allow determination of the most limiting combination of augmented radial peaking and core boundary conditions.

The key input parameters and their values used in the analyses of this event are consistent with, or conservative relative to, the Reference 15.4-10 approved methodology. See Table 15.0-27 for key input parameter values.

- Load Demand – A constant turbine load demand at full power was assumed.
- Trip Setpoints and Delays – Conservative trip setpoints and delay times were used.

15.4.3.3 Results

Full-length CEA Subgroup and Full-length CEA Drop

Full-length CEA drops result in a negative reactivity insertion. Full-length CEA subgroup drops typically result in a negative reactivity insertion greater than 500 pcm. The core is not adversely affected during this period since power is decreasing rapidly.

Following a CEA Drop Event power may be reestablished by reactivity feedback. In cases where reactivity feedback does not offset the worth of the dropped CEA, a cooldown condition exists until a reactor trip is reached on a Thermal Margin/Low Pressure (floor) or a low steam generator pressure signal. Figures 15.4.3-1 through 15.4.3-4 show typical transient response of

a dropped CEA of 500 pcm worth at a moderator temperature coefficient of 0 pcm/°F. In cases where reactivity is large enough to offset the worth of the dropped CEA, reactor power is reestablished at the original power level at a reduced reactor coolant system temperature and pressure condition. Figures 15.4.3-5 through 15.4.3-8 show a typical transient response of a dropped CEA of 500 pcm worth at a moderator temperature coefficient of -25 pcm/°F. In all cases, the minimum DNBR remains greater than the limit value.

Following plant stabilization, the operator may manually retrieve the CEA by following approved operating procedures.

AREVA Analyses

The MDNBR and peak LHR results for all cases are given in Table 15.4.3-4. The limiting MDNBR was calculated to be 1.554, which is above the 95/95 limit of 1.164 for the HTP CHF correlation. The peak LHR for the 1000 pcm case was calculated to be 15.71 kW/ft, which bounds the other cases and is less than the FCM limit.

The sequence of events for the DNB-limiting (25 pcm) case is given in Table 15.4.3-3, and the transient response for that case is shown in Figure 15.4.3-9 through Figure 15.4.3-12. For the 25 pcm case, the indicated thermal power does not change significantly, and the VHP trip setpoint is not reached. Thus, no reactor trip occurs. Without the occurrence of a reactor trip, the power asymptotically reaches a new steady value near the initial power level. The maximum return-to-power was calculated to be 3029.8 MW_t and is reported at the end of the calculation, when there is no significant increase in reactor power and no significant change in any of the parameters that are input to the DNBR calculation. EC287528

15.4.3.4 Conclusions

Following a limiting CEA Drop condition event, the plant will return to a stabilized condition at the initial power level. Results of the analysis show that a CEA Drop Event does not adversely affect the core, since the DNBR remains above the safety analysis limit value for a bounding range of dropped CEA worths.

15.4.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP AT AN INCORRECT TEMPERATURE

Based on Technical Specification 3.4.1.1, both reactor coolant loops and both reactor coolant pumps in each loop must be in operation in Modes 1 and 2. Therefore, this event is precluded and this section does not apply to St. Lucie Unit 2. This is not changed by the transition to AREVA fuel. EC287528

15.4.5 A MALFUNCTION OR FAILURE OF THE FLOW CONTROLLER IN A BWR RECIRCULATION LOOP THAT RESULTS IN AN INCREASED REACTOR COOLANT FLOW RATE (NOT APPLICABLE TO ST. LUCIE UNIT 2)

This section is not applicable to St. Lucie Unit 2. This is not changed by the transition to AREVA fuel. EC287528

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT RESULTS IN A DECREASE IN THE BORON CONCENTRATION IN THE REACTOR COOLANT

15.4.6.1 Accident Description

An Uncontrolled Boron Dilution event is defined as any event caused by a malfunction or an inadvertent operation of the CVCS that results in a dilution of the active portion of the RCS. The active portion of the RCS is defined as that volume of water that circulates through the core. For example, when in shutdown cooling (SDC), no credit is allowed for the volume of water in the stagnant portions of the RCS. A dilution of the RCS can be the result of adding water, which has a boron concentration that is less than the system boron concentration.

The CVCS regulates both the chemistry and the quantity of coolant in the RCS. Changing the boron concentration in the RCS is a part of normal plant operation, compensating for long-term reactivity effects such as fuel burnup, xenon buildup and decay, and plant startup. During refueling operations, borated water is supplied from the refueling water tank (RWT). EC287528

Boron concentration in the RCS can be decreased by controlled addition of demineralized water. During normal operation, concentrated boric acid solution and demineralized water is introduced into the volume control tank in concentrations corresponding to the required concentration for proper plant operation. A purification ion exchanger with a deborating resin is normally used for boron removal when the boron concentration in the RCS is low and the feed and bleed method becomes inefficient. The following provide a direct indication of a boron dilution in process:

- BDAS - Boron Dilution Alarm System (UFSAR 7.7.1.1.11), which provides alarm,
- and sampling.

The CVCS malfunction analysis (boron dilution) is performed to ensure that the analysis results meet the acceptance criteria for all modes, and remain consistent with the BDAS setpoint and sampling frequency for Modes 3, 4, 5, and 6.

To cover all phases of plant operation, boron dilution during refueling, cold shutdown, hot shutdown, hot standby, startup, and power modes of operation is considered in this analysis. Assumptions used in the analysis result in conservative determinations of the time available for operator or system response after detection of a dilution transient in progress. Dilution flow rates listed for each mode are based on the dilution source fluid conditions for reactor makeup water at 40°F and 14.7 psia. The analysis results are based on calculations which account for density compensation between the dilution source conditions and the mode-specific RCS conditions listed.

15.4.6.2 Method of Analysis

Boron dilutions during all six modes of operation (refueling, cold shutdown, hot shutdown, hot standby, startup, and power operation) are considered in this analysis. The analysis assumed complete mixing in the RCS. The rate of change of boron concentration during dilution is described by the following equation:

$$M\frac{dc}{dt} = -WC \qquad [15.4.6\text{-}1]$$

where

M = RCS mass

C = RCS boron concentration

W = charging mass flow rate of unborated water

The solution of equation 15.4.2.3-1 can be written

$$C(t) = C(o)e^{-t/\tau} \qquad [15.4.6\text{-}2]$$

where

τ = M/W = boron dilution time constant

C (*o*) = initial boron concentration

The change in boron concentration is

$$DC(t) = C(o) - C(t) \qquad [15.4.6\text{-}3]$$

or

$$DC(t) = C(o)\left[1 - e^{-t/\tau}\right] \qquad [15.4.6\text{-}4]$$

and the reactivity insertion is given by:

$$\text{Reactivity Insertion} \quad (t) = \frac{C(o)}{IBW}\left[1 - e^{-t/\tau}\right] \qquad [15.4.6\text{-}5]$$

where

IBW = Inverse Boron Worth

The time required to dilute to criticality is given by

$$T = \tau \ln\left[\frac{C(o)}{Ccrit}\right] \qquad [15.4.6\text{-}6]$$

where

C (o) = critical boron concentration

C_{crit} = critical boron concentration

τ is a time constant, defined by the total active RCS mass divided by the unborated dilution mass rate

Equation 15.4.6-6 was used to generate the time from initiation of the event until criticality. Alarm setpoints were chosen to ensure that the minimum time criterion to lose shutdown margin was preserved. The reactivity insertion, corresponding to the time mentioned above was used to generate the startup channel alarm setpoint.

Dilution during Refueling (Mode 6)

The plant is normally maintained in Mode 6 at the beginning of cycle when fuel is being loaded and arranged in the core and at the end of cycle for the removal of spent fuel. Mode 6 is also used for the performance of plant maintenance. In Mode 6, when the head bolts are being tensioned or detensioned for the replacement or removal of the vessel head, the water level in the vessel is maintained below the top of the flange. The primary coolant forced flow is provided by the shutdown cooling system (SCS). Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode.

The following conditions are assumed for the limiting Mode 6 analysis with the RCS drained to the hot leg centerline:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.

- A minimum RCS water volume of 3410 ft^3 is assumed, which is more conservative (that is, smaller) than the volume necessary to fill the reactor vessel up to the mid-plane of the nozzles plus the volume of one SCS train.

- The minimum boron concentration during refueling ($k_{eff} < 0.95$) and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload process.

Dilution during Cold Shutdown (Mode 5)

In this mode, the plant is being taken from a long-term mode of operation, refueling (Mode 6), to a short-term mode of operation, hot shutdown (Mode 4). Typically, the plant is maintained in the cold shutdown mode when reduced RCS inventory is necessary or ambient temperatures are required. The water level can be dropped to the mid-plane of the hot leg for maintenance work that requires the steam generators to be drained. The limiting scenario for Mode 5 is typically the case where the vessel is drained and the reactor is shut down by boron to the technical specifications requirement. Cases with 1, 2, and 3 charging pumps operating are analyzed for the case with the water level at (or above) the hot leg centerline, and with 1 charging pump for the case with the water level at the bottom of the hot leg. The boron dilution event is analyzed assuming the following conditions:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.

- Minimum RCS water volumes of 3410 ft^3 corresponding to the active RCS volume (not including the pressurizer volume) for the case with the water level at the hot leg

centerline, and 2655 ft^3 corresponding to the active RCS volume for the case with the water level at the bottom of the hot leg are assumed.

- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload verification process.

Dilution during Hot Shutdown (Mode 4)

In Mode 4, the plant is being taken from a short-term mode of operation, cold shutdown (Mode 5) to a long-term mode of operation, hot standby (Mode 3). Typically, the plant is maintained in the hot shutdown mode to achieve plant heatup before entering Mode 3. In Mode 4, the primary coolant forced flow can be provided by either the SCS or an RCP, depending on the system pressure. Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode. The boron dilution event in Mode 4 is analyzed assuming the following conditions:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.

- A minimum RCS water volume of 3711 ft^3 corresponding to the active RCS volume (not including the pressurizer volume) is assumed for the case with the plant on shutdown cooling system with no RCPs running. A minimum RCS water volume of 8332 ft^3 (not including the pressurizer volume and including the effects of 10% SGTP) is assumed for the case with the plant operating with at least one RCP running.

- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload verification process.

Dilution during Hot Standby (Mode 3)

In Mode 3, the plant is being taken from one short-term mode of operation, hot shutdown (Mode 4), to another, startup (Mode 2). The plant is maintained in Mode 3 at the beginning of cycle for startup testing of certain systems and to achieve plant heatup before entering Mode 2 and going critical. During cycle operation, the plant will enter Mode 3 following a reactor trip or as the result of a technical specification action statement. In Mode 3, all reactor coolant pumps may not be in operation. If the control rods are withdrawn to the HZP insertion limits, the inadvertent dilution scenario is similar to the Mode 2 analysis. Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode. Conditions assumed for the analysis are:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.

- A minimum RCS water volume of 8332 ft^3 corresponding to the active RCS volume (not including the pressurizer volume and including the effects of 10% steam generator tube plugging) with at least one RCP running is assumed.

- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload verification process.

Dilution during Startup (Mode 2)

In this mode, the plant is being taken from one long-term mode of operation, hot standby (Mode 3), to another, power (Mode 1). All normal actions required to change power level require operator initiation. For a normal approach to criticality, the operator manually initiates a limited dilution and manually withdraws the control rods. Conditions assumed for the analysis are:

- Dilution flow is the maximum capacity of all three charging pumps, 147 gpm.
- A minimum RCS water volume of 8332 ft^3 corresponding to the active RCS volume (not including the pressurizer and including the effects of 10% steam generator tube plugging) is assumed.
- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions during startup are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

This mode of operation is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to take the plant critical. During this mode, the plant is in manual rod control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator must manually initiate a limited dilution and withdraw the control rods. This process takes several hours. The technical specifications require that the reactor does not go critical with the control rods below the insertion limits. For inadvertent boron dilution with slow reactivity additions, this event is bounded by the CEA withdrawal event. For fast reactivity additions, this event is protected by the high rate of change of power reactor trip. Once dilution has been identified, the operator terminates the flow of non-borated water.

Dilution at Power (Mode 1)

The plant is operated at power with the rod control system in the manual mode. The analysis is performed assuming three charging pumps are in operation. Conditions assumed for this mode are:

- Dilution flow is the maximum capacity of all three charging pumps, 147 gpm.
- A minimum RCS water volume of 8332 ft^3 at 581.5°F is assumed. This is a very conservative estimate of the active RCS volume (not including the pressurizer and including the effects of 10% steam generator tube plugging).
- The maximum critical boron concentration (corresponding to the rods inserted to the insertion limits) and the minimum change in boron concentration from this initial condition to an HZP critical condition with all rods inserted are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process. Full rod insertion, minus the most reactive stuck rod, is assumed to occur due to reactor trip.

If the dilution is not secured, the reactor will be shut down by either the TM/LP reactor trip, the high pressurizer pressure (HPP) reactor trip or the variable high power trip (VHPT).

Once dilution has been identified, the operator terminates the flow of non-borated water.

15.4.6.3 Results

Analyses to determine the extent of fuel cladding damage and the overpressurization of the RCS are not done for this event. Instead, a calculation is performed to determine the amount of time available for operator action prior to the loss of the plant shutdown margin due to the dilution. Fifteen minutes for modes 1, 2, 3, 4, and 5 and thirty minutes for the refueling condition (Mode 6) of plant operation for operator action are the criteria outlined in the Standard Review Plan (SRP), Section 15.4.6. If these operator action times are met, it can be concluded that the fuel cladding damage and RCS overpressurization criteria are also satisfied.

The results provided below are based on using representative St. Lucie Unit 2 boron concentration values, which will be verified every cycle.

Dilution during Refueling (Mode 6)

For dilution during refueling, the maximum time available for alarm annunciation, such that the 30-minute operator action criterion remains satisfied, is 75, 40, 30 minutes with 1, 2, or 3 charging pumps, respectively.

Dilution during Cold Shutdown (Mode 5 - filled to hot leg centerline)

For dilution during cold shutdown (filled to hot leg centerline), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 30 minutes with 1, 2, or 3 charging pumps.

Dilution during Cold Shutdown (Mode 5 - drained to bottom of hot leg)

For dilution during cold shutdown (drained to bottom of hot leg), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 30 minutes with 1 charging pump.

Dilution during Hot Shutdown (Mode 4 - at least one RCP operating)

For dilution during hot shutdown (at least one RCP operating), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 130, 50, 30 minutes with 1, 2, or 3 charging pumps, respectively.

Dilution during Hot Shutdown (Mode 4 - with Shutdown Cooling System)

For dilution during hot shutdown (with SCS), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 75, 35, 30 minutes with 1, 2, or 3 charging pumps, respectively.

Dilution during Hot Standby (Mode 3)

For dilution during hot standby, the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 100, 40, 25 minutes with 1, 2, or 3 charging pumps, respectively.

For Dilution during Startup (Mode 2)

For dilution during startup, the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied is 100 minutes.

For Dilution during Full-Power Operation (Mode 1)

With the reactor in manual control, if no operator action is taken, the power and temperature rise causes the reactor to reach the HPP reactor trip setpoint. The boron dilution accident in this case is essentially identical to a CEA withdrawal accident at power. Prior to the HPP trip, an HPP alarm would be actuated. There is sufficient time available (89 minutes) after a reactor trip for the operator to determine the cause of dilution, isolate the reactor makeup water source, and initiate reboration before the reactor can return to criticality.

Monitoring Frequency

Should the automatic boron dilution alarm be inoperable, UFSAR Section 13.7.2.4 contains requirements for the maximum frequency of RCS chemistry sampling. These sampling frequencies ensure that the specified criteria are met to ensure sufficient time is available to the operators, from the detection of dilution until criticality is achieved to mitigate the consequences of this event. The backup boron dilution detection monitoring frequencies provided in UFSAR Table 13.7.2-3 are verified every cycle and changed as necessary.

15.4.6.4 Conclusions

The time sequence of events is provided in Table 15.4.6-1. These times meet the requirements specified in Table 13.7.2-3. The boron dilution analyses at refueling, cold shutdown, hot shutdown, hot standby, startup, and full-power conditions show the acceptability of the EPU with up to 10% steam generator tube plugging. These results and conclusions remain valid with the transition to AREVA fuel. EC287528

15.4.7 INADVERTENT LOADING OF A FUEL ASSEMBLY

The original analysis provided the following considerations:

The fuel enrichment within a fuel assembly is identified by a coded serial number marked on the exposed surface of the upper end fitting of the fuel assembly. This serial number is used as a means of positive identification for each assembly in the plant. A status board is provided in the refueling control center showing a schematic representation of the reactor core, spent fuel pool and new fuel storage area. During the period of core loading, the location of each CEA, fuel assembly, and source will be shown by its identification number on this status board.

The status board in the refueling control center will be constantly updated by a designated member of the reactor operations staff whenever a fuel assembly is being moved. The staff member in the refueling control center will be in constant communication with each area where this is occurring. Also, a senior licensed operator will be present during alteration of the core to directly supervise the activity and ensure that the assemblies are moved to the correct locations. Fuel assemblies will not be moved unless these lines of communication are available. In addition to these precautions, periodic independent inventories of components in the reactor core, spent fuel, and new fuel storage areas will be made to ensure that the status board is correct. Also, at the completion of core loading, the exposed surfaces of the upper end fittings are inspected to verify that all assemblies are correctly located. These precautions are included in the core loading procedures which are to be reviewed by appropriate plant personnel.

If, however, in spite of these precautions it is assumed that an assembly is placed in the wrong core position, then many possibilities exist. The worst situation would be the interchange of two assemblies of equal BOC K-inf, but different poison rod loading, as will be shown below.

If, in spite of the extreme precautions described above, it is postulated that a fuel assembly is misloaded, several situations may be postulated. The misloading of a fuel assembly may effect the core power distribution only slightly, for example, if assemblies of similar enrichments and reactivities are misloaded. Alternatively, the core power distribution may be affected enough so that core performance would be affected if assemblies having different enrichments or reactivities are misloaded.

In the unlikely event that two assemblies of different enrichments would be interchanged, some misloadings would be detected using ex-core startup detectors and the reactivity computer during the low power physics testing. In this testing a symmetry check is performed in which the reactivity worths of symmetrically located CEAs are compared against one another with the aid of the ex-core startup detectors and the reactivity computer. In these events of assembly misloading, this check would indicate significantly different CEA worths between symmetrically located CEAs. This asymmetry would be corroborated by symmetry checks performed for other symmetric rod groups thereby indicating a fuel misloading. Table 15.4.7-1 shows the worths of two symmetrically located CEAs insert into the core misloaded by:

a. Interchanging a type A and Type B assembly near the core center.

b. Interchanging a Type B and Type C assembly near the core periphery.

Figures 15.4.7-1 and 15.4.7-2 show the loading patterns for these misloadings and the locations of the two symmetrically located CEAs.

Table 15.4.7-1 clearly shows that detectable differences exist in the worths of two symmetrically located CEAs for each of these misloadings and therefore demonstrates the detectability of the misloading.

In addition, the misloading could be detected by either the ex-core detectors directly or the incore detector channels which become operable during the power generating mode of operation. Figures 15.4.7-3 and 15.4.7-4 show the core power distributions for the above misloadings for an unrodded core.

As shown above, many of the fuel assembly misloadings that can be postulated are easily detectable both during the rod symmetry checks and during power range operation. However, one can postulate a small number of misloadings which are undetectable during the rod symmetry testing or even early in the cycle with incore instrumentation during power range operation. Of this small class certainly the worst case that can be envisioned is the interchange of a shimmed assembly with an unshimmed one at the center of the core. This case may not be detectable at BOL, but may still cause local power peaking as the shims burn out. Two cases of this type of misloading accident are shown in Figures 15.4.7-5 and 15.4.7-6. The maximum pin power peaks occurring with these misloads are presented in Table 15.4.7-2. The minimum DNBR associated with this power distribution is 1.61 for the worst case (Figure 15.4.7-6). Since this is greater than the 1.19 DNBR limit, no clad damage is predicted. Furthermore, it is very probable that these misloadings will be detected early in the cycle before these maximum pin peaks are attained. Certainly the reactor operator would be alerted to the possibility of a fuel assembly misloading by the rather large power perturbations (e.g., tilts on the order of eight-

nine percent) which would begin to appear early in the cycle, which should be detectable by the incore instrumentation. Tilt amplitudes are normally expected to be two percent.

In view of the foregoing, it is not expected that these misloads would significantly affect reactor safety or result in offsite dose consequences which are a measurable fraction of the guidelines established for design basis accidents.

The analysis above concludes that misloads that are not easily detectable would not significantly affect reactor safety or result in offsite dose consequences, which are a measurable fraction of guidelines established for design basis accidents. This conclusion remains unaffected by implementation of EPU. The transition to AREVA fuel does not affect the previous conclusion, and no additional analyses were performed as a result. EC287528

15.4.8 SPECTRUM OF CONTROL ELEMENT ASSEMBLY EJECTION ACCIDENTS

15.4.8.1 Accident Description

This accident is the result of postulated mechanical failure of a control element drive mechanism (CEDM) pressure housing such that the reactor coolant system (RCS) pressure would eject the CEA and drive shaft. The consequences of this mechanical failure, in addition to being a minor LOCA, may also be a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Rapid ejection of a CEA from the core would require a complete circumferential break of the CEDM housing or the CEDM nozzle on the reactor vessel head. The CEDM housing and CEDM nozzle are an extension of the reactor coolant system boundary and designed and manufactured to Section III of the ASME boiler and Pressure Vessel Code. Hence, the occurrence of such a failure is considered highly unlikely.

If a CEA ejection accident were to occur, a fuel rod thermal transient that could cause a Departure from Nucleate Boiling (DNB) may occur together with limited fuel damage. The amount of fuel damage that can result from such an accident will be governed mainly by the worth of the ejected CEA and the power distribution attained with the remaining control element pattern. The transient is limited by the Doppler reactivity effects of the increase in fuel temperature and is terminated by reactor trip actuated by the high power level trip. The transient is terminated before conditions are reached that can result in damage to the reactor coolant pressure boundary, or significant disturbances in the core, its support structures or other reactor pressure vessel internals that would impair the capability to cool the core.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler Power Coefficient (DPC). This self limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a CEA ejection accident occur, the following automatic features of the reactor protection system are available to terminate the transient:

- Variable Power Level Trip High
- Rate-of-Change of Power Trip High

Setpoints assumed and trip functions are summarized in Table 15.0-29.

The ultimate acceptance criteria for this event is that any consequential damage to either the core or the RCS must not prevent long-term core cooling, and that any offsite dose consequences must be within the guidelines established for design basis accidents. To demonstrate compliance with these requirements, it is sufficient to show that the RCS pressure boundary remains intact, and that no fuel dispersal in the coolant, gross lattice distortions, or severe shock waves will occur in the core. Therefore, the following acceptance criteria are applied to the CEA ejection accident:

- Maximum average fuel pellet enthalpy at the hot spot must remain below 200 cal/g (360 Btu/lbm).
- Peak RCS pressure must remain below that which would cause the stresses in the RCS to exceed the faulted condition stress limits.
- Maximum fuel melting must be limited to the innermost 10 percent of the fuel pellet at the hot spot, independent of the above pellet enthalpy limit.

For the AREVA fuel thermal analyses, the following acceptance criteria are applicable:

- The total radially averaged enthalpy deposition at the fuel hot spot must remain below 230 cal/g (for fuel coolability).
- The peak fuel temperature must remain below the fuel melting point (for fuel coolability).
- The total extent of fuel rod failures from exceeding either of the following two limits must be less than that assumed in the radiological consequences analysis: EC287528
  - Total radially averaged fuel hot spot enthalpy deposition less than 150 cal/g (to avoid pellet / cladding mechanical interaction [PCMI])
  - MDNBR greater than 95/95 DNBR limit (to avoid DNB)

15.4.8.2 Method of Analysis

The calculation of the CEA ejection transient is performed in two stages: a core neutron kinetic analysis and a hot-spot fuel heat transfer analysis. The spatial neutron kinetics code TWINKLE (Reference 15.4-1) is used in a 1-D axial kinetics model to calculate the core nuclear power including the various total core feedback effects; that is, Doppler reactivity and moderator reactivity. The average core nuclear power is multiplied by the post-ejection hot-channel factor, and the fuel enthalpy and temperature transients at the hot spot are calculated with the detailed fuel and cladding transient heat transfer computer code, FACTRAN (Reference 15.4-2). The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient. Additional details of the methodology are provided in WCAP-7588 (Reference 15.4-3).

In calculating the nuclear power and hot-spot fuel rod transients following CEA ejection, the following conservative assumptions are made:

1. The maximum uncertainties are applied to the initial conditions in the conservative direction. The analysis assumes uncertainties of 3.0°F in nominal vessel T_{avg}, and

45 psi in nominal pressurizer pressure. The core power used represents the upper limit on core power.

2. A minimum value for the delayed neutron fraction for BOC and EOC conditions is assumed, which increases the rate at which the nuclear power increases following CEA ejection.

3. A minimum value of the Doppler power defect is assumed, which conservatively results in the maximum amount of energy deposited in the fuel following CEA ejection. A minimum value of the moderator feedback is also assumed. A positive MTC is assumed for the BOC, zero-power case.

4. Maximum values of ejected CEA worth and post-ejection total hot-channel factors are assumed for all cases considered. These parameters are calculated using standard nuclear design codes for the maximum allowed bank insertion at a given power level as determined by the rod insertion limits. No credit is taken for the flux flattening effects of reactivity feedback.

5. The total time for CEA ejection is assumed to be 0.05 seconds.

6. For the HZP cases, the reactor is assumed to be tripped by the nuclear power signal of the Variable High Power (VHP) trip at the lower limit (floor) setpoint. For the HFP cases, the reactor trip is assumed to occur on the variable power level function of the VHP trip at a conservative setpoint. Appropriate error allowances are added to the Technical Specification setpoints to determine the analysis trip point. A trip time delay of 0.4 seconds for reactor trip breaker opening is used, with the control rods assumed to start moving 0.74 seconds after breaker opening.

7. The analysis conservatively assumes the trip rods are inserted starting from the fully withdrawn position, using a conservative rod position versus time curve. Also, the total trip reactivity is based on the conservative assumption that the highest worth adjacent CEA is stuck in its fully withdrawn position in addition to the ejected rod.

8. Both UO_2-only fuel and 8 weight percent (w/o) gadolinium-doped fuel were modeled in the analysis.

AREVA Fuel Thermal Analyses

With the approved non-LOCA methodology given in Reference 15.4-10, the S-RELAP5 code was used to model the key system components and calculate the neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and maximum fuel centerline temperature. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 15.4-11), which was used to calculate the MDNBR using the HTP CHF correlation (Reference 15.4-12). Deposited enthalpy was calculated using the Reference 15.4-14 methodology. EC287528

Eight different initial-condition cases were analyzed for the event: (1) BOC full power, (2) EOC full power, (3) BOC 65% RTP, (4) EOC 65% RTP, (5) BOC 20% RTP, (6) EOC 20% RTP, (7) BOC HZP, and (8) EOC HZP. Per the TS, the core is held subcritical by more than 1% Δρ for Mode 3 (Hot Standby), Mode 4 (Hot Shutdown), and Mode 5 (Cold Shutdown). Since 1% Δρ is

more than the worth of the ejected control rod, evaluation of these modes is not required. For this analysis, HZP was assumed to be Mode 2 (Startup).

All four reactor coolant pumps were assumed to be in operation for both Mode 1 (Power Operation) and Mode 2 (Startup).

Conservative assumptions are typically used to bias the RCS pressure transient response. For evaluation of DNB, the RCS pressure was held constant at the initial value and was assumed to neither increase nor decrease.

The key input parameters and their assumed values (listed in Table 15.4.8-2a) used in the analyses of this event are consistent with, or conservative relative to, the approved Reference 15.4-10 methodology. See Table 15.0-27 for additional key input parameter values.

- Initial Conditions – The analyses were performed from full power, 65% RTP, 20% RTP and HZP initial conditions. Respective maximum core inlet temperatures were assumed for each initial condition. The TS minimum RCS flow rate was used.

- Reactivity Feedback – Due to the rapidity of the transient, moderator feedback has a second-order impact on the consequences. TS/COLR MTC limits were used for the cases initiated at BOC, whereas conservatively biased “least negative” EOC MTCs were used for the EOC cases. The event is initially mitigated by the negative Doppler reactivity feedback. As such, the Doppler reactivity assumed in the analyses was conservatively biased to minimize the negative feedback due to increasing fuel temperatures. For the HZP initiated cases, fuel temperature dependent Doppler feedback was used. EC287528

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay actuation of the trip function. In addition, rod insertion was delayed to account for the CEA holding coil release delay time.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters, and PORVs) parameters and equipment states were selected to reduce the primary system pressure.

- Ejected CEA Worth – To maximize the reactor power response to the ejected CEA, a conservatively high ejected CEA worth was assumed for each case, based on St. Lucie Unit 2 specific rod patterns and power-dependent insertion limits.

- Gap Conductances and Fuel Thermal Properties – Fuel-to-cladding gap conductances and fuel thermal properties that account for TCD were applied. BOC or EOC gap conductances and fuel properties, consistent with the time-in-cycle for the reactivity coefficients, were conservatively chosen.

- Single Failure – Because the systems designed to mitigate this event (namely, the RPS) are redundant, there is no single active failure that will adversely affect the consequences of the event.

15.4.8.3 Results

Figures 15.4.8-1 through 15.4.8-8 present the nuclear power and hot-spot fuel rod thermal transients for the CEA ejection cases analyzed. The transient results of the analysis are summarized in Table 15.4.8-1. A time sequence of events is provided in Table 15.4.8-2. For all cases, the maximum fuel pellet enthalpy remained below 200 cal/g, and the peak hot-spot fuel centerline temperature remained below the fuel melting temperature (4900°F at BOC and 4800°F at EOC for UO_2-only; 4816°F at BOC and 4717°F at EOC for 8 w/o gad-doped fuel). The Gd_2O_3-doped UO_2 fuel was found to be more limiting for cases. The 8 w/o gad-doped fuel (without taking credit for the power suppression due to the gadolinium) was more limiting for the HFP cases.

AREVA Fuel Thermal Analyses

The sequence of events is shown in Table 15.4.8-2b. Results are given in Table 15.4.8-2c and Table 15.4.8-2d. The fuel coolability enthalpy and avoidance-of-melting criteria were met for all cases. Also, no fuel rod failures due to PCMI or DNB were predicted.

The BOC full power case presented the most significant challenge to the DNB and PCMI limits. The transient response is shown in Figure 15.4.8-9 through Figure 15.4.8-14. Figure 15.4.8-9 shows the reactor power as a function of time. Figure 15.4.8-10 shows the core power based on rod surface heat flux. Figure 15.4.8-11 through Figure 15.4.8-14 show the RCS loop temperatures, reactivity feedback, peak fuel centerline temperatures, and pressurizer pressure, respectively. EC287528

The BOC 20% RTP case presented the most significant challenge to the FCM acceptance criterion. The transient response is shown in Figure 15.4.8-15 through Figure 15.4.8-20. Figure 15.4.8-15 shows the reactor power as a function of time. Figure 15.4.8-16 shows the core power based on rod surface heat flux. Figure 15.4.8-17 through Figure 15.4.8-20 show the RCS loop temperatures, reactivity feedback, peak fuel centerline temperatures, and pressurizer pressure, respectively.

15.4.8.4 Radiological Analysis

15.4.8.4.1 Background

This event consists of an uncontrolled withdrawal of a single control element assembly (CEA). This event is the same as the Rod Ejection event referred to in RG 1.183. The CEA Ejection results in a reactivity insertion that leads to a core power level increase and subsequent reactor trip. Following the reactor trip, plant cooldown is performed using steam release from the SG ADVs. Two CEA Ejection cases are considered. The first case assumes that 100% of the activity released from the damaged fuel is instantaneously and homogeneously mixed throughout the containment atmosphere. The second case assumes that 100% of the activity released from the damaged fuel is completely dissolved in the primary coolant and is available for release to the secondary system. The St. Lucie Unit 2 AST dose analysis methodology is presented in NAI-1101-044, “AST Licensing Technical Report for St. Lucie Unit 2”.

15.4.8.4.2 Compliance with RG 1.183 Regulatory Positions

The CEA Ejection dose consequence analysis followed the guidance provided in RG 1.183 Appendix H, "Assumptions for Evaluating the Radiological Consequences of a PWR Rod Ejection Accident," as discussed below:

1. Regulatory Position 1 - The total core inventory of the radionuclide groups utilized for determining the source term for this event is based on RG 1.183, Regulatory Position 3.1, and is provided in Table 15.0-32. The inventory provided in Table 15.0-32 is adjusted for the fraction of fuel damaged and a radial peaking factor of 1.65 is applied. The release fractions provided in RG 1.183 Table 3 are adjusted to comply with the specific RG 1.183 Appendix H release requirements. For both the containment and secondary release cases, the activity available for release from the fuel gap for fuel that experiences DNB is assumed to be 10% of the noble gas and iodine inventory in the DNB fuel. For the containment release case for fuel that experiences fuel centerline melt (FCM), 100% of the noble gas and 25% of the iodine inventory in the melted fuel is assumed to be released to the containment. For the secondary release case for fuel that experiences FCM, 100% of the noble gas and 50% of the iodine inventory in the melted fuel is assumed to be released to the primary coolant.

2. Regulatory Position 2 - Fuel damage is assumed for this event.

3. Regulatory Position 3 - For the containment release case, 100% of the activity released from the damaged fuel is assumed to mix instantaneously and homogeneously in the containment atmosphere. For the secondary release case, 100% of the activity released from the damaged fuel is assumed to mix instantaneously and homogeneously in the primary coolant and be available for leakage to the secondary side of the SGs.

4. Regulatory Position 4 - The chemical form of radioiodine released from the damaged fuel to the containment is assumed to be 95% cesium iodide (CsI), 4.85% elemental iodine, and 0.15% organic iodide. Containment sump pH is controlled to 7.0 or higher.

5. Regulatory Position 5 - The chemical form of radioiodine released from the SGs to the environment is assumed to be 97% elemental iodine, and 3% organic iodide.

6. Regulatory Position 6.1 - For the containment leakage case, natural deposition in the containment is credited. In addition, the shield building ventilation system (SBVS) is credited. Containment spray is not credited.

7. Regulatory Position 6.2 - The containment is assumed to leak at the TS maximum allowable rate of 0.5% for the first 24 hours and 0.25% for the remainder of the event.

8. Regulatory Position 7.1 - The primary-to-secondary leak rate is apportioned between the SGs as specified by TS 6.8.4.l (0.5 gpm total, 0.25 to any one SG).

9. Regulatory Position 7.2 - The density used in converting volumetric leak rates to mass leak rates is based upon RCS conditions, consistent with the plant design basis

10. Regulatory Position 7.3 - All of the noble gas released to the secondary side is assumed to be released directly to the environment without reduction or mitigation.

11. Regulatory Position 7.4 - Regulatory Position 7.4 refers to Appendix E, Regulatory Positions 5.5 and 5.6. The iodine transport model for release from the steam generators is as follows:

    - Appendix E, Regulatory Position 5.5.1 - For the secondary release case, both steam generators are used for plant cooldown. A portion of the primary-to-secondary leakage is assumed to flash to vapor based on the thermodynamic conditions in the reactor and secondary immediately following plant trip when tube uncovery is postulated. The primary- to-secondary leakage is assumed to mix with the secondary water without flashing during periods of total tube submergence.

    - Appendix E, Regulatory Position 5.5.2 - The portion of leakage that immediately flashes to vapor is assumed to rise through the bulk water of the SG, enter the steam space, and be immediately released to the environment with no mitigation; i.e., no reduction for scrubbing within the SG bulk water is credited.

    - Appendix E, Regulatory Position 5.5.3 - All of the SG tube leakage that does not flash is assumed to mix with the bulk water.

    - Appendix E, Regulatory Position 5.5.4 - The radioactivity within the bulk water is assumed to become vapor at a rate that is a function of the steaming rate and the partition coefficient. A partition coefficient of 100 is assumed for the iodine. The retention of particulate radionuclides in the SGs is limited by the moisture carryover from the SG. The same partition coefficient of 100, as used for iodine, is assumed for other particulate radionuclides. This assumption is consistent with the SG carryover rate of less than 1%.

    - Appendix E, Regulatory Position 5.6 - Steam generator tube bundle uncovery in the SGs is postulated for up to 45 minutes following a reactor trip for St. Lucie Unit 2. During this period, the fraction of primary-to-secondary leakage which flashes to vapor is assumed to rise through the bulk water of the SG into the steam space and is assumed to be immediately released to the environment with no mitigation. The flashing fraction is based on the thermodynamic conditions in the reactor and secondary coolant. The leakage which does not flash is assumed to mix with the bulk water in the steam generator. A conservative uncovery time of 60 seconds was assumed in the analysis.

15.4.8.4.3 Other Assumptions

1. The initial RCS activity is assumed to be at the TS 3.4.8 limit of 1.0 μCi/gm Dose Equivalent I-131 and 518.9 μCi/gm DE Xe-133. The initial SG activity is assumed to be at the TS 3.7.1.4 limit of 0.1 μCi/gm Dose Equivalent I-131.

2. The steam mass release rates for the SGs are provided in Table 15.4.8-5.

3. The RCS fluid density used to convert the primary-to-secondary leakage from a volumetric flowrate to a mass flow rate is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. The high initial cooldown rate conservatively maximizes the fluid density. The SG tube leakage mass flow rate is provided in Table 15.4.8-6.

4. The RCS mass is assumed to remain constant throughout the event.

5. For the purposes of determining the iodine concentrations, the SG mass is assumed to remain constant throughout the event. However, it is also assumed that operator action is taken to restore secondary water level above the top of the tubes within a conservative time of one hour following a reactor trip.

6. Following the CEA Ejection event, 9.5% of the fuel is assumed to fail as a result of DNB and 0.5% of the fuel is assumed to experience fuel centerline melt.

7. All secondary releases are postulated to occur from the ADV with the most limiting atmospheric dispersion factors. Releases from containment through the SBVS are assumed to be released from the plant stack with a filter efficiency of 99% for particulates and 95% for both elemental and organic iodine. The activity that bypasses the SBVS is released unfiltered to the environment via a ground level release from containment.

8. The initial leakage rate from containment is 0.5% of the containment volume per day. This leak rate is reduced by 50% after 24 hours to 0.25% /day. 9.6% of the containment leakage is assumed to bypass the SBVS filters.

9. For the release inside of containment, natural deposition of the radionuclides is credited consistent with the LOCA methodology presented in Section 15.6.5.5.3. Containment sprays are not credited.

15.4.8.4.4 Methodology

Input assumptions used in the dose consequence analysis of the CEA Ejection are provided in Table 15.4.8-4. The postulated accident consists of two cases. One case assumes that 100% of the activity released from the damaged fuel is instantaneously and homogeneously mixed throughout the containment atmosphere, and the second case assumes that 100% of the activity released from the damaged fuel is completely dissolved in the primary coolant and is available for release to the secondary system.

For the containment release case, 100% of the activity is released instantaneously to the containment. The releases from the containment correspond to the same leakage points discussed for the LOCA in Section 15.6.5.5.3. Natural deposition of the released activity inside of containment is credited. In addition, the shield building ventilation system (SBVS) is credited. Removal of activity via containment spray is not credited.

For the secondary release case, primary coolant activity is released into the SGs by leakage across the SG tubes. The activity on the secondary side is then released via steaming from the ADVs until the RCS is cooled to 212°F. All noble gases associated with this leakage are

assumed to be released directly to the environment. The primary-to-secondary leakage is assumed to continue until the faulted steam generator is completely isolated at 12.4 hours. In addition, the analysis assumes that the initial iodine activity of both SGs is immediately released to the environment. The secondary coolant iodine concentration is assumed to be the maximum value of 0.1 μCi/gm DE I-131 permitted by TS. These release assumptions are consistent with the requirements of RG 1.183.

The CEA Ejection is evaluated with the assumption that 0.5% of the fuel experiences FCM and 9.5% of the fuel experiences DNB. The activity released from the damaged fuel corresponds to the requirements set out in Regulatory Position 1 of Appendix H to RG 1.183. A radial peaking factor of 1.65 is applied in the development of the source terms.

For this event, the Control Room ventilation system cycles through three modes of operation:

- Initially the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 395 cfm of unfiltered inleakage.

- After the start of the event, the Control Room is isolated due to a high radiation reading in the Control Room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 395 cfm of unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

- At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.

- The Control Room ventilation filter efficiencies that are applied to the filtered makeup and recirculation flows are 99% for particulate, and 95% for elemental iodine, and organic iodine.

15.4.8.4.5 Radiological Consequences

The Control Room atmospheric dispersion factors (χ/Qs) used for this event are based on the postulated release locations and the operational mode of the control room ventilation system. The release-receptor point locations are chosen to minimize the distance from the release point to the Control Room air intake.

For the CEA secondary side release case, releases from the SGs are assumed to occur from the ADV that produces the most limiting χ/Qs. When the Control Room Ventilation System is in normal mode, the most limiting χ/Q corresponds to the worst air intake to the control room. When the ventilation system is isolated, the limiting χ/Q corresponds to the midpoint between the two control room air intakes. The operators are assumed to reopen the most favorable air intake at 1.5 hours. Development of control room atmospheric dispersion factors is discussed in Appendix 2.5D. The χ/Qs for the secondary releases are summarized in Table 15.4.8-7. For the CEA inside of containment release case, the χ/Qs for containment leakage are assumed to be identical to those for the LOCA discussed in Section 15.6.5.5.4.

For the EAB dose analysis, the χ/Q factor for the zero to two-hour time interval is assumed for all time periods. Using the zero to two-hour χ/Q factor provides a more conservative determination of the EAB dose, because the χ/Q factor for this time period is higher than for any other time period. The LPZ dose is determined using the χ/Q factors for the appropriate time intervals. These χ/Q factors are provided in Appendix 2.5C.

The radiological consequences of the CEA Ejection are analyzed using the RADTRAD-NAI code and the inputs/assumptions previously discussed. As shown in Table 15.4.8-3, the results of both cases for EAB dose, LPZ dose, and Control Room dose are all within the appropriate regulatory acceptance criteria.

15.4.8.5 Conclusions

The analysis performed has demonstrated that, for the CEA ejection event, the fuel thermal criteria are not exceeded. Based on the generic assessment in WCAP-7588, Revision 1-A (Reference 15.4-3), the peak reactor coolant pressure will be less than that which would cause stresses to exceed the Faulted Condition stress limits. In addition, based on the generic assessment in Reference 15.4-3, the number of rods in DNB is expected to not exceed 9.5%. Therefore, all acceptance criteria for this event have been met.

Radiological consequences calculated based on 0.5% of the rods in centerline melting and 9.5% of the rods in DNB were found to be well within the guidelines established for design basis accidents.

15.4.9 REFERENCES

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15.4-10 EMF-2310(P)(A) Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

15.4-11 XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, August 1983.

15.4-12 EMF-92-153(P)(A) Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005. EC287528

15.4-13 ANP-3347P Revision 0, St. Lucie Unit 2 Fuel Transition Chapter 15 Non LOCA Summary Report, AREVA Inc., December 2014.

15.4-14 XN-NF-78-44(NP)(A), A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors, Exxon Nuclear Company, September 1983.

Table 15.4.1-1
Sequence of Events
Uncontrolled CEA Withdrawal from a Subcritical Condition

Event	**Time (seconds)**
Initiation of Uncontrolled CEA Bank Withdrawal	0.0
Variable High Power Trip Setpoint (Lower Limit Setting) is Reached	13.4
Peak Nuclear Power Occurs	13.7
Rod Motion Begins	14.6
Peak Heat Flux Occurs	15.1
Minimum DNBR Occurs	15.1
Peak Cladding Temperature Occurs	15.3
Peak Fuel Average Temperature Occurs	15.8
Peak Fuel Centerline Temperature Occurs	16.7

Table 15.4.1-2 Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): Sequence of Events

Event	Time (sec)
Bank withdrawal begins	0.00
Indicated reactor power reaches VHP trip setpoint	36.46
Reactor trip signal is generated	37.57
CEAs insertion begins	38.32
Maximum actual power is reached	38.34
Maximum heat flux power occurs	39.64
MDNBR occurs	39.64
Maximum fuel hot spot centerline temperature occurs	41.00

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Table 15.4.1-3 Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): Results

Criterion	Result
MDNBR	1.994
Peak centerline temperature	3194ºF

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Table 15.4.2-1 Time Sequence of Events for Uncontrolled CEA Withdrawal at Power (100% Initial Power & Minimum Reactivity Feedback)	
Event	**Time (Seconds)***
Case A:	
Initiation of Uncontrolled CEA Withdrawal at Full Power with Maximum Reactivity Feedback (53 pcm/sec)	0.0
High Pressurizer Pressure Trip Setpoint Reached	11.14
High Pressurizer Pressure Trip Signal Obtained	12.89
Rods Begin to Fall into Core	14.03
Minimum DNBR Occurs	14.10
Case B:	
Initiation of Uncontrolled CEA Withdrawal at Full Power with Maximum Reactivity Feedback (2 pcm/sec)	0.0
Thermal Margin Low Pressure Trip Setpoint Reached	765.18
Rods Begin to Fall into Core	766.84
Minimum DNBR occurs	765.00

* The 20 second steady state has been subtracted from the noted times.

Table 15.4.2-2
Limiting Results for CEA Bank Withdrawal at Power Transient

Criterion	Limiting Value	Analysis Limit	Case
DNBR	1.74	1.42	100% power, maximum reactivity feedback, 53 pcm/second reactivity insertion rate
Core Heat Flux (FON)	1.246	1.27	100% power, maximum reactivity} feedback 53 pcm/second reactivity insertion rate
MSS Pressure (psia)	1090.74	1100.0	100% power, maximum reactivity feedback, 2 pcm/second reactivity insertion rate

Table 15.4.2-3 Uncontrolled CEA Withdrawal at BOC Full Power (AREVA SAFDLs): Sequence of Events for DNB-Limiting Case

Event	Time (sec)
Bank withdrawal with 0.08 pcm/sec reactivity insertion rate begins	0.00
Pressurizer pressure reaches HPP trip setpoint, pressurizer PORVs open, and pressurizer pressure peaks	166.62
NI power reaches VHP trip setpoint	166.92
Reactor is scrammed on VHP (including signal processing delay)	167.32
Core heat flux through cladding peaks (117.8% RTP)	167.71
MDNBR occurs	167.85
CEA insertion begins, and reactor power peaks (118.5% RTP)	168.07

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Table 15.4.2-4 Uncontrolled CEA Withdrawal at Power (AREVA SAFDLs): Results for Limiting Cases

Initial Power Level	BOC		EOC	
	MDNBR	Peak LHR	MDNBR	Peak LHR
Full power	1.177	Bounded(1)	1.184	Bounded(1)
90% RTP	1.206	16.43 kW/ft	1.241	Bounded(1)
65% RTP	1.484	Bounded(1)	1.435	Bounded(1)
20% RTP	2.735	Bounded(1)	2.744	Bounded(1)

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(1) Bounded by value for BOC 90% RTP

Table 15.4.3-1 Sequence of Events Dropped CEA with Reactor Trip 500 pcm Drop Rod Worth, 0 MTC Case	
Event	**Time (Seconds)**
Initiation of the Event	20.00
Dropped CEA Falls to Bottom of Core	20.01
TMLP Reactor Trip Setpoint Reached	59.42
Maximum Post-Trip Core Heat Flux Occurs (0.6971 frac. of nominal)	61.36
Rods Begin to Fall	61.36

Table 15.4.3-2 Sequence of Events Dropped CEA without Reactor Trip 500 pcm Drop Rod Worth, -25 MTC Case	
Event	**Time (Seconds)**
Initiation of the Event	20.00
Dropped CEA Falls to Bottom of Core	20.01
Return to (near) initial power conditions (1.0090 frac. of nominal)	130.00

Table 15.4.3-3 Dropped CEA (AREVA): Sequence of Events for DNB-Limiting Case	
Event	Time (sec)
25-pcm-worth rod drop is initiated	0.0
Minimum actual reactor power (2940.2 MW_t) occurs	3.0
Maximum return-to-power (3029.8 MW_t) occurs	300.0

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Table 15.4.3-4 Dropped CEA (AREVA): Results				
Criterion	25 pcm Case	200 pcm Case	500 pcm Case	1000 pcm Case
MDNBR	1.554	1.578	1.630	1.702
Peak LHR	Bounded(1)	Bounded(1)	Bounded(1)	15.71 kW/ft

EC287528

(1) Bounded by value for 1000 pcm case

Table 15.4.6-1
Uncontrolled Boron Dilution Sequence of Events

Mode		Event	Time (minutes)
Refueling (Mode 6)		Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	76 (1 charging pump) 45 (2 charging pumps) 33 (3 charging pumps)
		Time from alarm annunciation to criticality	>30
Cold Shutdown (Mode 5)	Filled to hot leg centerline	Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	32 (1 charging pump) 38 (2 charging pumps) 33 (3 charging pumps)
		Time from alarm annunciation to criticality	>15
	Drained to the bottom of hot leg	Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	33 (1 charging pump)
		Time from alarm annunciation to criticality	>15
Hot Shutdown (Mode 4)	At least one RCP operating	Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	194 (1 charging pump) 89 (2 charging pumps) 54 (3 charging pumps)
		Time from alarm annunciation to criticality	>15
	Shutdown Cooling System (SCS)	Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	78 (1 charging pump) 31 (2 charging pumps) 15 (3 charging pumps)
		Time from alarm annunciation to criticality	>15
Hot Standby (Mode 3)		Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	196 (1 charging pump) 90 (2 charging pumps) 55 (3 charging pumps)
		Time from alarm annunciation to criticality	>15
Startup (Mode 2)		Dilution begins	0
		Maximum Available time from initiation of boron dilution to alarm annunciation	85
		Time from alarm annunciation to criticality	>15
At Power (Mode 1)		Dilution begins	0
		HPP reactor trip signal reached	5
		Rod motion begins	5.03
		Shutdown margin is lost (if dilution continues after trip)	>15

Table 15.4.7-1 Worths of Symmetrically Located CEAs Inserted Into a Misloaded 217 Assembly Core (Cycle 1)

	CEA Worth (%Δρ)	
Misloading	**CEA in Quadrant 1**	**Symmetric CEA in Quadrant 3**
Interchange of Type A and Type B assemblies near core center	0.114	0.089
Interchange of Type B and Type C assemblies near the core periphery	0.336	0.025

Table 15.4.7-2 Maximum Pin Power Peaks Occuring With Worst Case Misloads (Cycle 1)

	Misloading	Cycle Max 1-pin Power Peak	Occurring At (MWD/T)	% Diff from Nominal
1.	None: Nominal 100% Power Case	1.420	2000	---
2.	Figure 15C-5*	1.657	6000	16.7
3.	Figure 15C-6*	1.745	2000	23.1

* Figure numbers refer to earlier FSAR amendments and are not included in the current amendment.

Table 15.4.8-1
Assumptions and Results – CEA Ejection

Beginning of Cycle	**Full Power**	**Zero Power**
Initial Power Level, %	100	0
Ejected CEA Worth, % Δk	0.25	0.60
Delayed Neutron Fraction	0.0050	0.0050
Doppler Power Defect, % Δk	0.900	0.900
Feedback Reactivity Weighting	1.262	2.633
Trip Reactivity, % Δk	3.0	2.0
F_Q Before Ejection	2.415	N/A
F_Q After Ejection	5.25	15.0
Number of RCPs Operating	4	4
Maximum Fuel Pellet Enthalpy, cal/g	151.4	78.2
Maximum Fuel Melted, %	None	None
End of Cycle	**Full Power**	**Zero Power**
Initial Power Level, %	100	0
Ejected CEA Worth, % Δk	0.25	0.60
Delayed Neutron Fraction	0.0044	0.0044
Doppler Power Defect, % Δk	0.900	0.900
Feedback Reactivity Weighting	1.262	3.802
Trip Reactivity, % Δk	3.0	2.0
F_Q Before Ejection	2.415	N/A
F_Q After Ejection	5.25	26.25
Number of RCPs Operating	4	4
Maximum Fuel Pellet Enthalpy, cal/g	141.3	88.7
Maximum Fuel Melted, %	None	None

Table 15.4.8-2 (Sheet 1 of 2) Sequence of Events CEA Ejection -- Beginning of Cycle Cases	
Beginning of Cycle - Hot Zero Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint (Lower Limit Setting) is Reached	0.49
Peak Nuclear Power Occurs	0.56
Rods Begin to Fall Into the Core	1.63
Peak Cladding Average Temperature Occurs	2.3
Peak Fuel Average Temperature Occurs	2.6
Beginning of Cycle - Hot Full Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint is Reached	0.03
Peak Nuclear Power Occurs	0.09
Rods Begin to Fall Into the Core	1.17
Peak Fuel Average Temperature Occurs	2.4
Peak Cladding Average Temperature Occurs	2.4

Table 15.4.8-2 (Sheet 2 of 2) Sequence of Events CEA Ejection -- End of Cycle Cases	
End of Cycle - Hot Zero Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint (Lower Limit Setting) is Reached	0.31
Peak Nuclear Power Occurs	0.36
Rods Begin to Fall Into the Core	1.45
Peak Cladding Average Temperature Occurs	1.8
Peak Fuel Average Temperature Occurs	2.0
End of Cycle - Hot Full Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint is Reached	0.03
Peak Nuclear Power Occurs	0.09
Rods Begin to Fall Into the Core	1.17
Peak Fuel Average Temperature Occurs	2.4
Peak Cladding Average Temperature Occurs	2.4

Table 15.4.8-2a CEA Ejection (AREVA Fuel Thermal): Assumptions				
Beginning of Cycle	**Full Power**	**65% RTP**	**20% RTP**	**HZP**
Initial Power Level, % RTP	100.3	65.0	20.0	0.0
Ejected CEA Worth, % Δk	0.280	0.370	0.540	0.620
Doppler Coefficient, % Δk / °F	0.00100	0.00110	0.00116	BOC table(1)
Trip Reactivity, % Δk	5.20	3.60	3.60	3.60
F_Q After Ejection(2)	2.681	4.550	6.240	4.867
Number of RCPs Operating	4	4	4	4
End of Cycle	**Full Power**	**65% RTP**	**20% RTP**	**HZP**
Initial Power Level, % RTP	100.3	65.0	20.0	0.0
Ejected CEA Worth, % Δk	0.061	0.115	0.280	0.525
Doppler Coefficient, % Δk / °F	0.00120	0.00121	0.00126	EOC table(3)
Trip Reactivity, % Δk	5.20	3.60	3.60	3.60
F_Q After Ejection(2)	2.320	3.984	7.271	8.781
Number of RCPs Operating	4	4	4	4

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(1) A table of BOC Doppler reactivity versus fuel temperature, biased less negative than nominal
(2) Before measurement, design allowance, and engineering uncertainties are added
(3) A table of EOC Doppler reactivity versus fuel temperature, biased less negative than nominal

Table 15.4.8-2b (Sheet 1 of 3) CEA Ejection (AREVA Fuel Thermal): Sequences of Events		
Case	Event	Time (sec)
BOC Full Power	Reactivity insertion begins	0.00
	VHP trip setpoint is reached	0.03
	Ejected CEA is fully withdrawn	0.05
	Reactor is scrammed on VHP (including signal processing delay)	0.43
	Maximum neutron power occurs	1.11
	CEA insertion begins	1.17
	Maximum average-core heat flux through cladding occurs	2.07
	MDNBR occurs	2.07
	Maximum fuel centerline temperature occurs	3.25
EOC Full Power	Reactivity insertion begins	0.00
	Ejected CEA is fully withdrawn	0.05
	VHP trip setpoint is reached	0.07
	Maximum neutron power occurs	0.11
	Reactor is scrammed on VHP (including signal processing delay)	0.47
	CEA insertion begins	1.21
	Maximum average-core heat flux through cladding occurs	1.34
	MDNBR occurs	1.34
	Maximum fuel centerline temperature occurs	3.11
BOC 65% RTP	Reactivity insertion begins	0.00
	VHP trip setpoint is reached	0.03
	Ejected CEA is fully withdrawn	0.05
	Reactor is scrammed on VHP (including signal processing delay)	0.44
	Maximum neutron power occurs	1.08
	CEA insertion begins	1.18
	Maximum average-core heat flux through cladding occurs	2.44
	MDNBR occurs	2.44
	Maximum fuel centerline temperature occurs	3.66

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Table 15.4.8-2b (Sheet 2 of 3) CEA Ejection (AREVA Fuel Thermal): Sequences of Events		
Case	Event	Time (sec)
EOC 65% RTP	Reactivity insertion begins	0.00
	Ejected CEA is fully withdrawn	0.05
	VHP trip setpoint is reached	0.07
	Maximum neutron power occurs	0.21
	Reactor is scrammed on VHP (including signal processing delay)	0.47
	CEA insertion begins	1.21
	Maximum average-core heat flux through cladding occurs	1.66
	MDNBR occurs	1.66
	Maximum fuel centerline temperature occurs	3.60
BOC 20% RTP	Reactivity insertion begins	0.00
	VHP trip setpoint is reached	0.05
	Ejected CEA is fully withdrawn	0.05
	Reactor is scrammed on VHP (including signal processing delay)	0.45
	Maximum neutron power occurs	1.07
	CEA insertion begins	1.19
	MDNBR occurs	2.58
	Maximum average-core heat flux through cladding occurs	2.59
	Maximum fuel centerline temperature occurs	3.84
	Reactivity insertion begins	0.00
EOC 20% RTP	Reactivity insertion begins	0.00
	Ejected CEA is fully withdrawn	0.05
	VHP trip setpoint is reached	0.10
	Reactor is scrammed on VHP (including signal processing delay)	0.50
	Maximum neutron power occurs	1.02
	CEA insertion begins	1.24
	MDNBR occurs	2.35
	Maximum average-core heat flux through cladding occurs	2.36
	Maximum fuel centerline temperature occurs	3.88

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Table 15.4.8-2b (Sheet 3 of 3) CEA Ejection (AREVA Fuel Thermal): Sequences of Events		
Case	Event	Time (sec)
BOC HZP	Reactivity insertion begins	0.00
	Ejected CEA is fully withdrawn	0.05
	VHP trip setpoint is reached	2.70
	Reactor is scrammed on VHP (including signal processing delay)	3.81
	Maximum neutron power occurs	4.48
	CEA insertion begins	4.56
	Maximum average-core heat flux through cladding occurs	5.79
	MDNBR occurs	5.79
	Maximum fuel centerline temperature occurs	7.55
EOC HZP	Reactivity insertion begins	0.00
	Ejected CEA is fully withdrawn	0.05
	VHP trip setpoint is reached	2.12
	Maximum neutron power occurs	2.19
	Reactor is scrammed on VHP (including signal processing delay)	3.23
	CEA insertion begins	3.98
	Maximum average-core heat flux through cladding occurs	4.93
	MDNBR occurs	4.93
	Maximum fuel centerline temperature occurs	6.62

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Table 15.4.8-2c CEA Ejection (AREVA Fuel Thermal): Full Power and 65% RTP Case Results					
	Full Power Cases		65% RTP Cases		
Criterion	BOC	EOC	BOC	EOC	Limit
MDNBR (% fuel failure)	1.179 (0%)	2.031 (0%)	1.246 (0%)	2.668 (0%)	1.164
Melt-limiting fuel type Centerline temperature FCM limit (% fuel failure)	UO_2-Gd_2O_3 4500°F [4611]°F (0%)	UO_2-Gd_2O_3 4103°F [4421]°F (0%)	Fresh all-UO_2 4860°F [4879]°F (0%)	UO_2-Gd_2O_3 3813°F [4421]°F (0%)	Case-specific (see left)
Deposited enthalpy (% fuel failure)	144.1 cal/g (0%)	136.9 cal/g (0%)	142.3 cal/g (0%)	135.7 cal/g (0%)	150 cal/g (PCMI)

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Table 15.4.8-2d CEA Ejection (AREVA Fuel Thermal): 20% RTP and HZP Case Results					
	20% RTP Cases		HZP Cases		
Criterion	BOC	EOC	BOC	EOC	Limit
MDNBR (% fuel failure)	1.193 (0%)	3.899 (0%)	2.104 (0%)	4.213 (0%)	1.164
Melt-limiting fuel type Centerline temperature FCM limit (% fuel failure)	Fresh all-UO_2 4876°F [4879]°F (0%)	UO_2-Gd_2O_3 2925°F [4421]°F (0%)	UO_2-Gd_2O_3 4010°F [4565]°F (0%)	UO_2-Gd_2O_3 2677°F [4421]°F (0%)	Case-specific (see left)
Deposited enthalpy (% fuel failure)	119.7 cal/g (0%)	126.0 cal/g (0%)	24.9 cal/g (0%)	26.9 cal/g (0%)	150 cal/g (PCMI)

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Table 15.4.8-3 CEA Ejection Dose Consequences			
Case	**EAB Dose(1) (rem TEDE)**	**LPZ Dose(2) (rem TEDE)**	**Control Room Dose(2) (rem TEDE)**
CEA Ejection – Containment Release	0.29	0.57	2.86
CEA Ejection – Secondary Release	0.31	0.73	3.12
Acceptance Criteria	6.3	6.3	5

(1) Worst 2-hour dose

(2) Integrated 30-day dose

Table 15.4.8-4 Control Element Assembly (CEA) Ejection – Inputs and Assumptions	
Input/Assumption	**Value**
Core Power Level	3030 MW_{th} (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o
Maximum Radial Peaking Factor	1.65
Percent of Fuel Rods in DNB	9.5%
Percent of Fuel Rods with Centerline Melt	0.5%
Core Fission Product Inventory	Table 15.0-32
Initial RCS Equilibrium Activity	1.0 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 gross activity (Table 15.6.5-15)
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/gm DE I-131 (Table 15.1.6-6)
Release Fraction from DNB Fuel Failures	Section 1 of Appendix H to RG 1.183
Release Fraction from Centerline Melt Fuel Failures	Section 1 of Appendix H to RG 1.183
Steam Generator Tube Leakage	0.5 gpm (Table 15.4.8-6)
Time to Terminate SG Tube Leakage	12.4 hours
Secondary Side Mass Releases to Environment	Table 15.4.8-5
SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	 1 hour 5 %
Steam Generator Secondary Side Partition Coefficient	Flashed tube flow – none Non-flashed tube flow – 100
Time to Reach 212 °F and Terminate Steam Release	12.4 hours
RCS Mass	minimum – 420,090 lb_m Minimum mass used for fuel failure dose contribution to maximum SG tube leakage activity

Table 15.4.8-4 (continued) Control Element Assembly (CEA) Ejection – Inputs and Assumptions	
Input/Assumption	**Value**
SG Secondary Side Mass	minimum – 128,390 -5% lb_m (per SG) maximum – 260,000 lb_m (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration.
Chemical Form of Iodine Released to Containment	Particulate – 95% Elemental – 4.85% Organic – 0.15%
Chemical Form of Iodine Released from SGs	Particulate – 0% Elemental – 97% Organic – 3%
Atmospheric Dispersion Factors Offsite Onsite	 Appendix 2.5C Table 15.4.8-7 and Appendix 2.5D
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	 30 seconds 1.5 hours 395 cfm
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6
Control Room Occupancy Factor	RG 1.183 Section 4.2.6
Containment Volume Containment Leakage Rate 0 to 24 hours after 24 hours	2.50E+06 ft^3 0.5% (by weight)/day 0.25% (by weight)/day
Secondary Containment Filter Efficiency	Particulate – 99% Elemental – 95% Organic – 95%
Secondary Containment Drawdown Time	310 seconds
Secondary Containment Bypass Fraction	9.6%
Containment Natural Deposition Coefficients	Aerosols – 0.1 hr^{-1} Elemental Iodine – 2.89 hr^{-1} Organic Iodine – None

Table 15.4.8-5 CEA Ejection Steam Release Rate	
Time (hours)	**SG Steam Release Rate (lb_m/min)**
0.0	11473.7
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0

Table 15.4.8-6 CEA Steam Generator Tube Leakage	
Time (hours)	**SG Tube Leakage (lb_m/min)**
0	3.15
0.50	3.34
1.00	3.50
1.50	3.65
2.00	3.71
4.00	3.80
6.00	3.89
9.00	3.96
11.00	4.00
12.40	0.00

Table 15.4.8-7 Control Room χ/Q for release from SG	
Time (hours)	**χ/Q (sec/m^3)**
0	6.71E-03
0.00833	3.13E-03
1.5	1.89E-03
2	1.53E-03
8	6.02E-04
24	4.55E-04
96	3.89E-04
720	3.89E-04

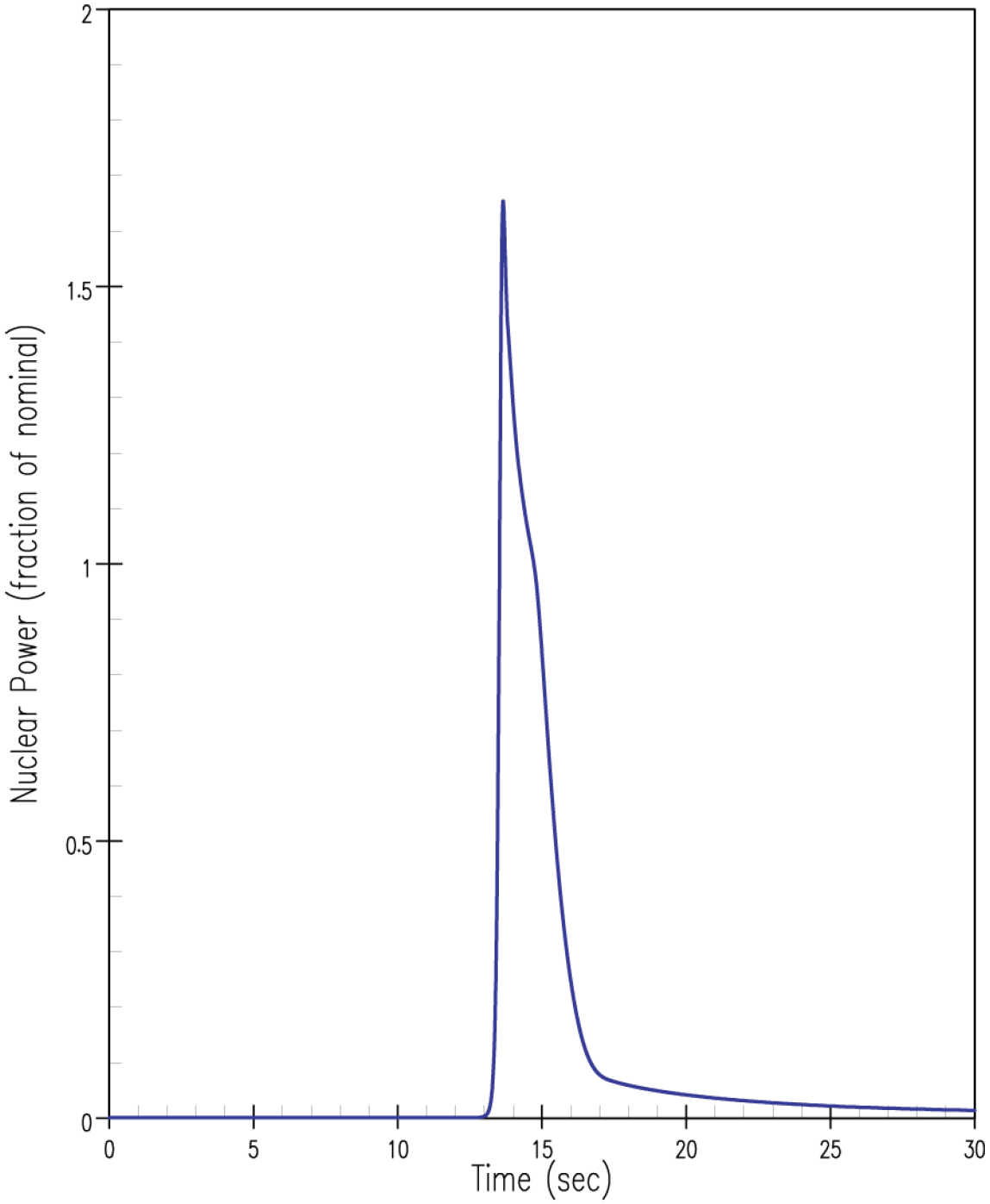

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FIGURE 15.4.1-1 Uncontrolled CEA Withdrawal from a Subcritical or Low Power Condition Nuclear Power vs. Time

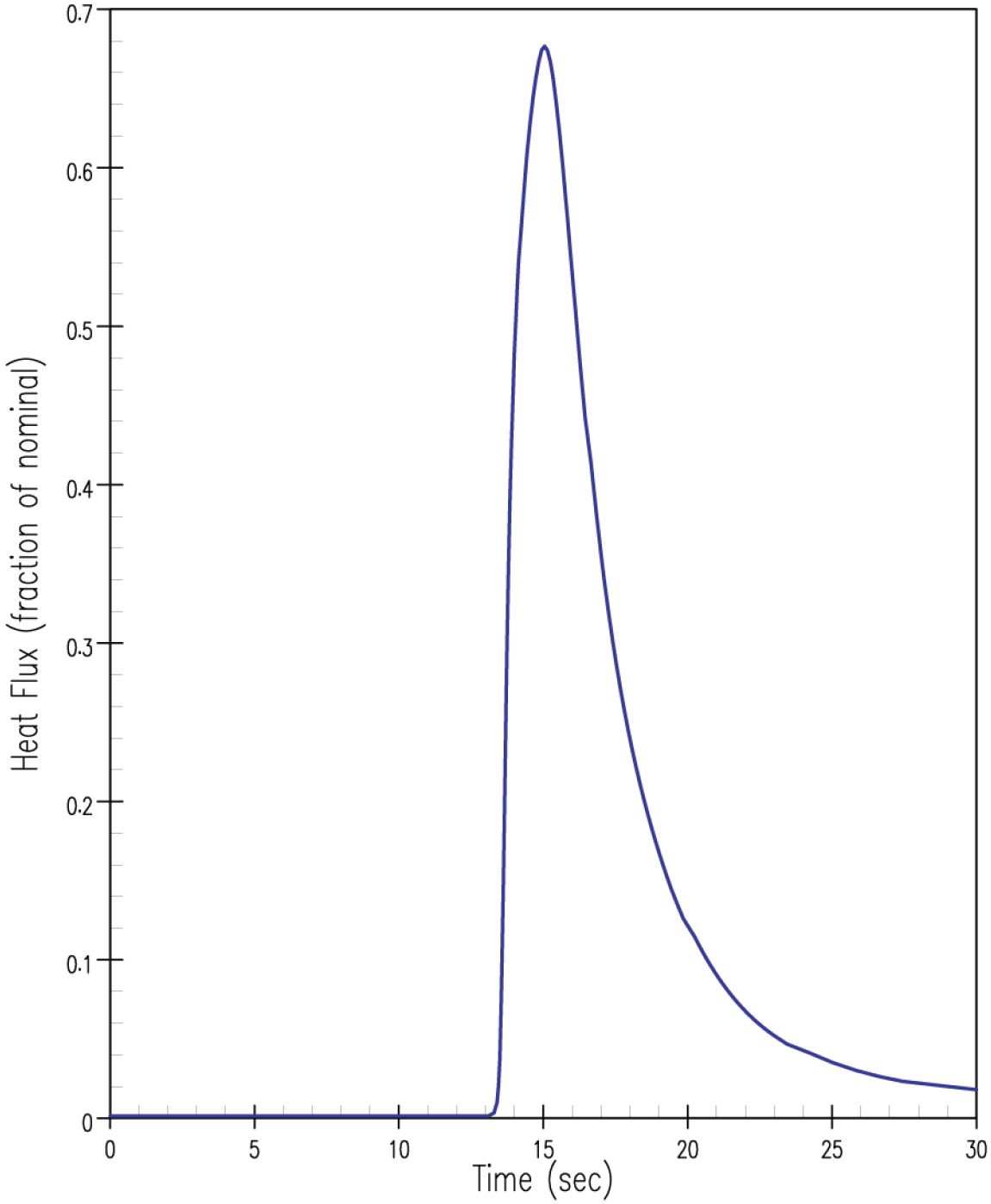

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FIGURE 15.4.1-2 Uncontrolled CEA Withdrawal from a Subcritical or Low Power Condition Heat Flux vs. Time

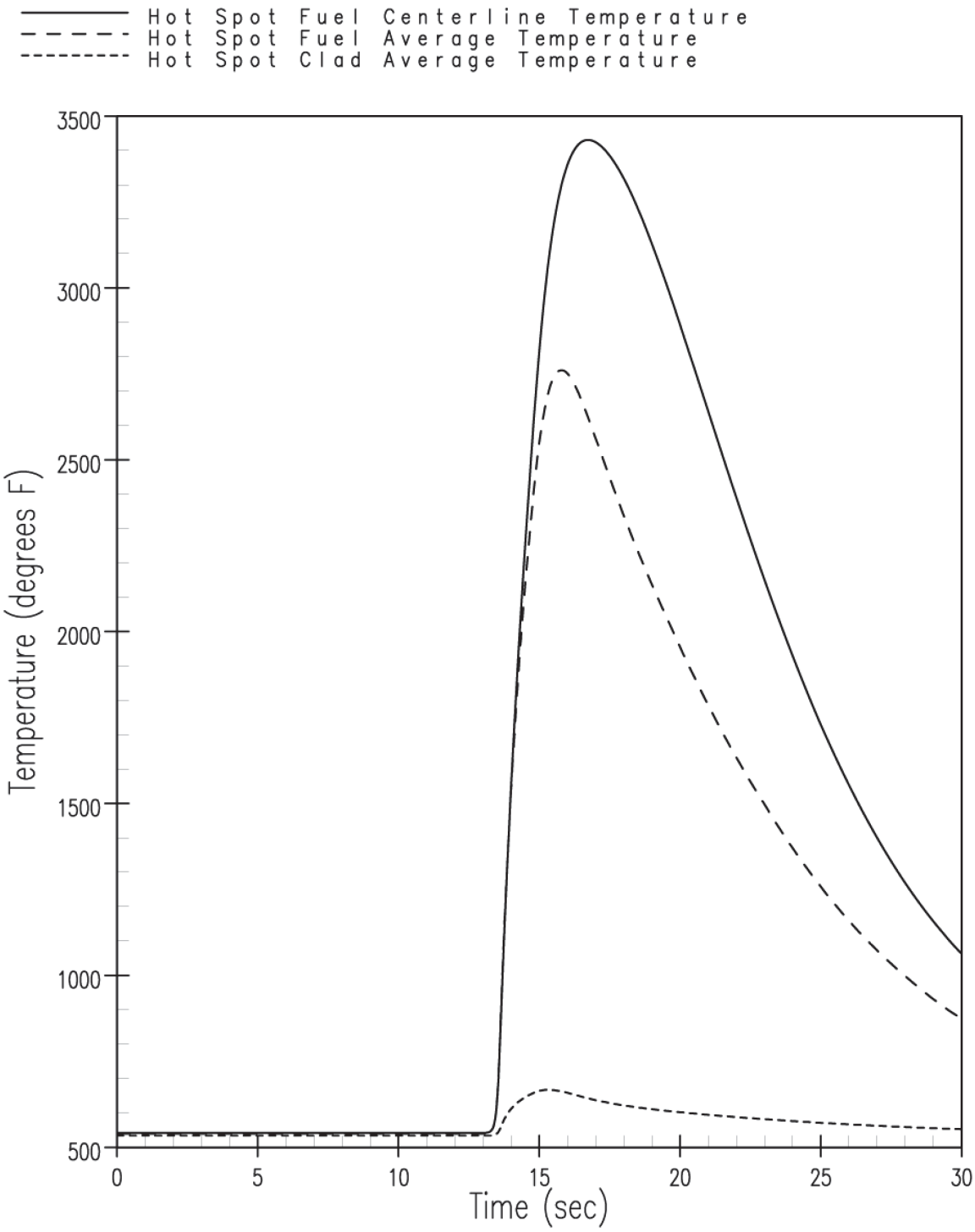

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FIGURE 15.4.1-3 Uncontrolled CEA Withdrawal from a Subcritical or Low Power Condition Hot Spot Temperature vs. Time

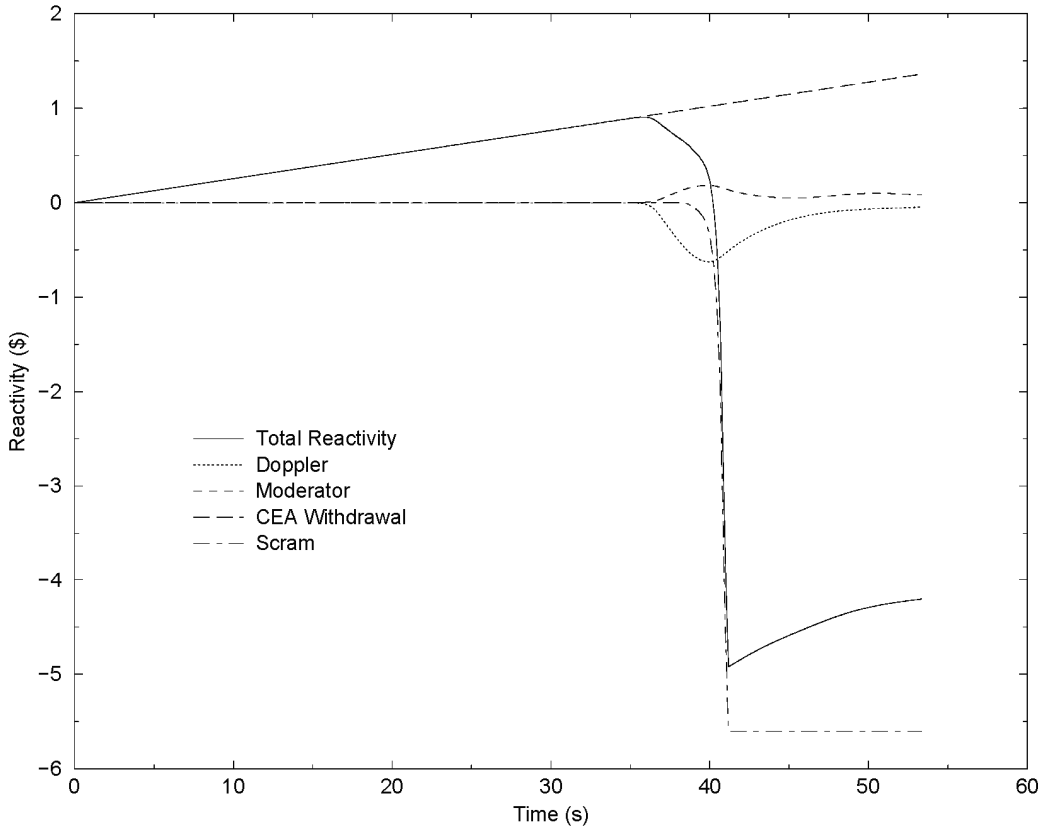

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Figure 15.4.1-4
Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): Reactivity Feedback vs. Time

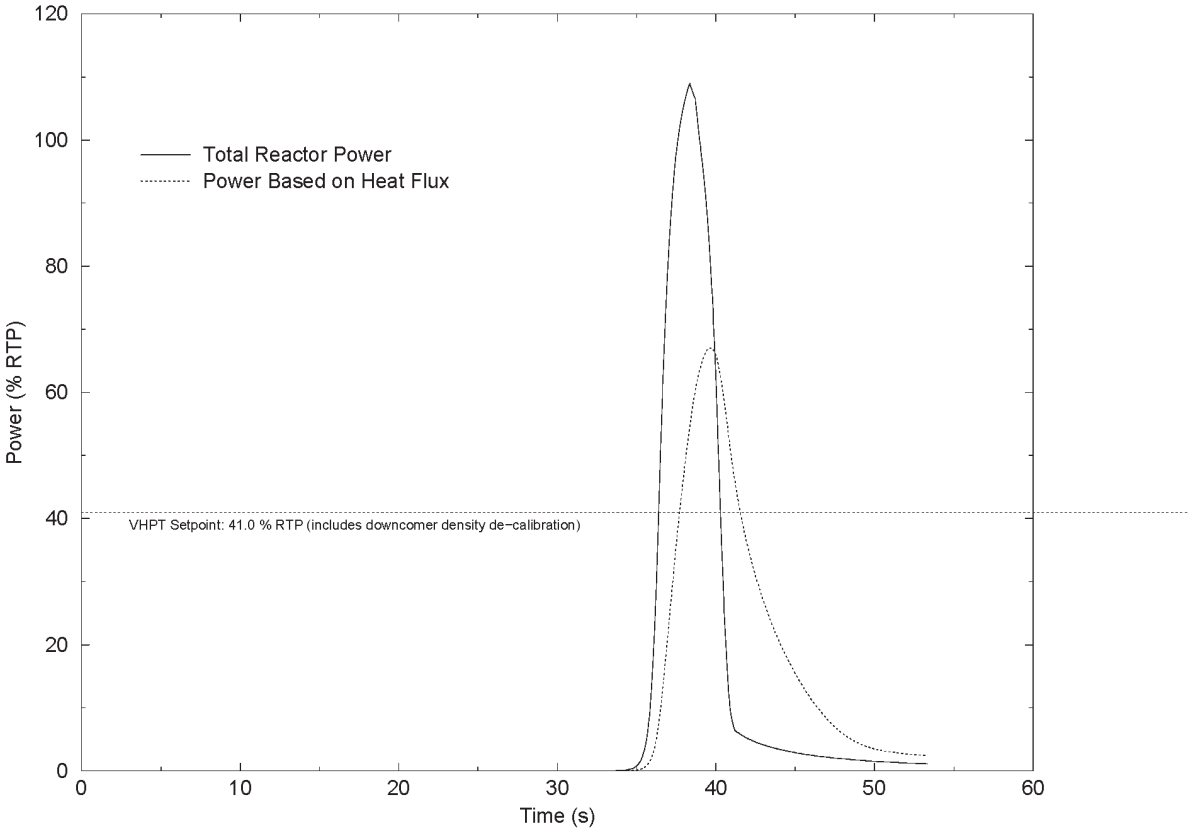

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Figure 15.4.1-5
Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): Reactor Power and Heat Flux vs. Time

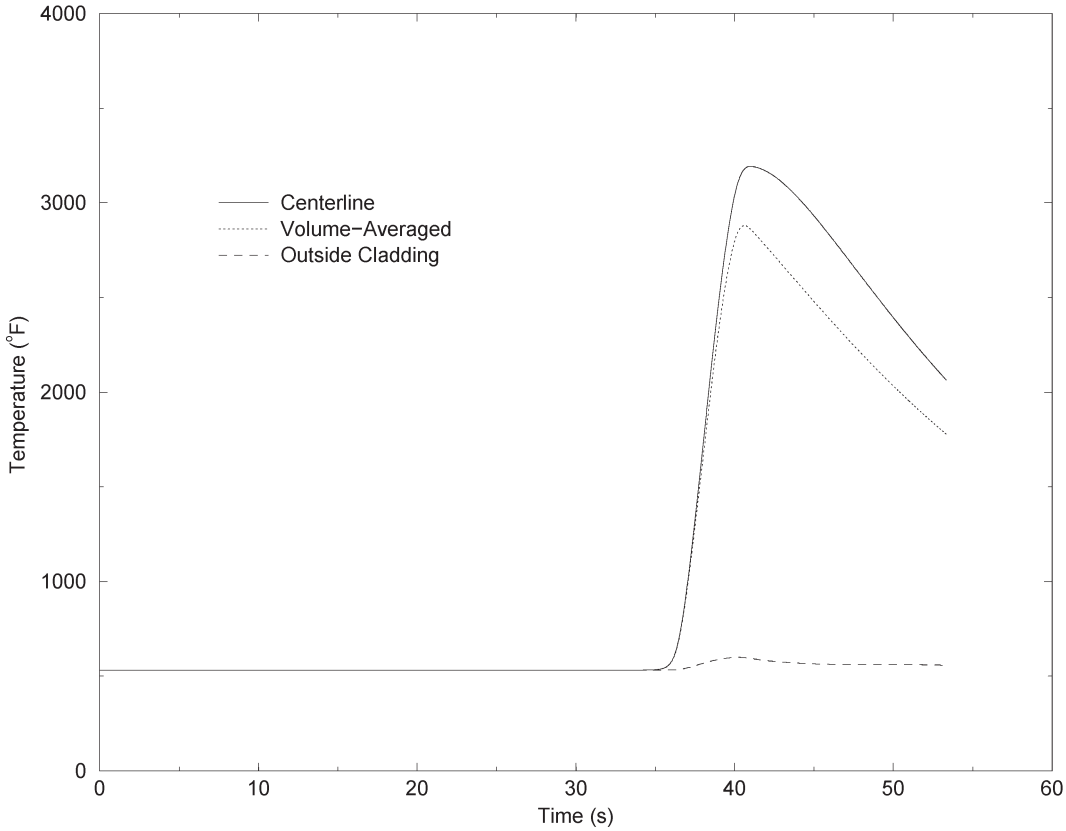

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Figure 15.4.1-6
Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): Hot Spot Temperatures vs. Time

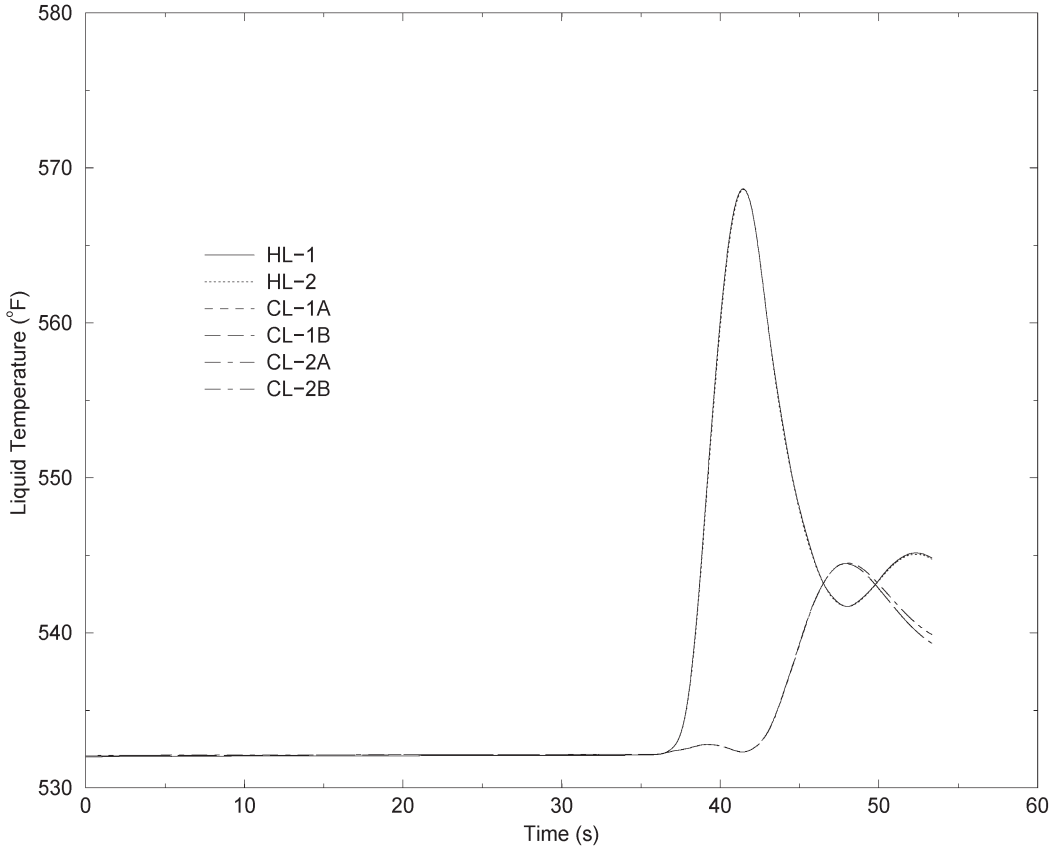

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Figure 15.4.1-7
Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): RCS Loop Temperatures vs. Time

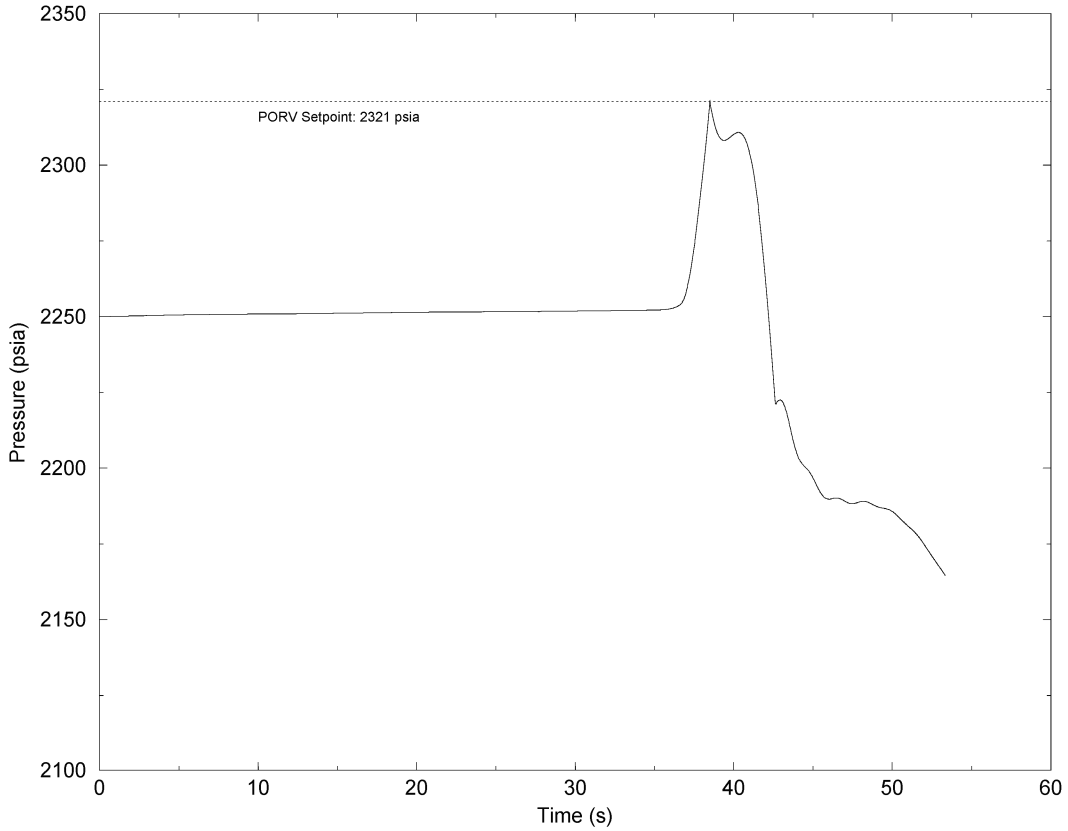

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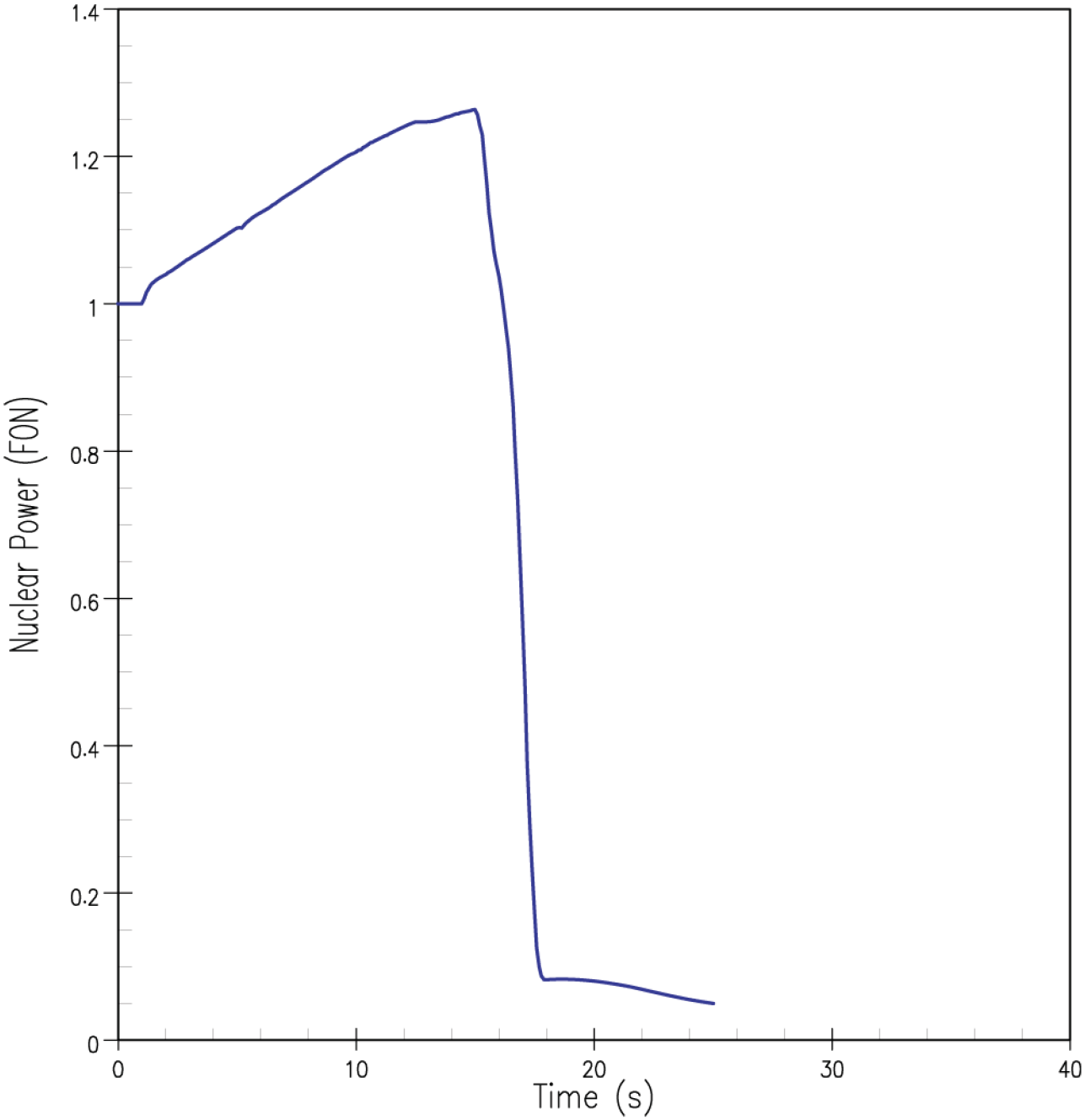
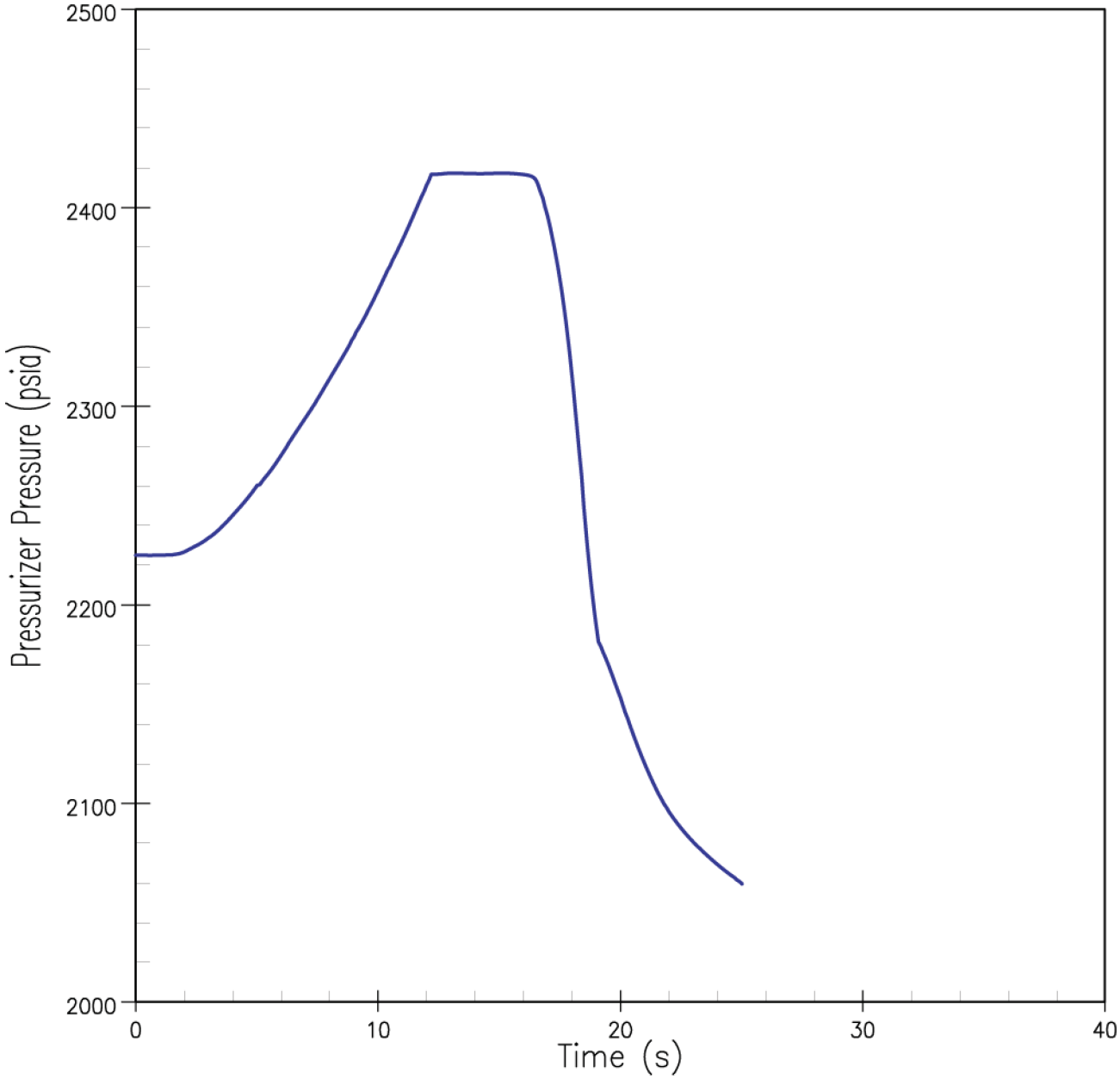
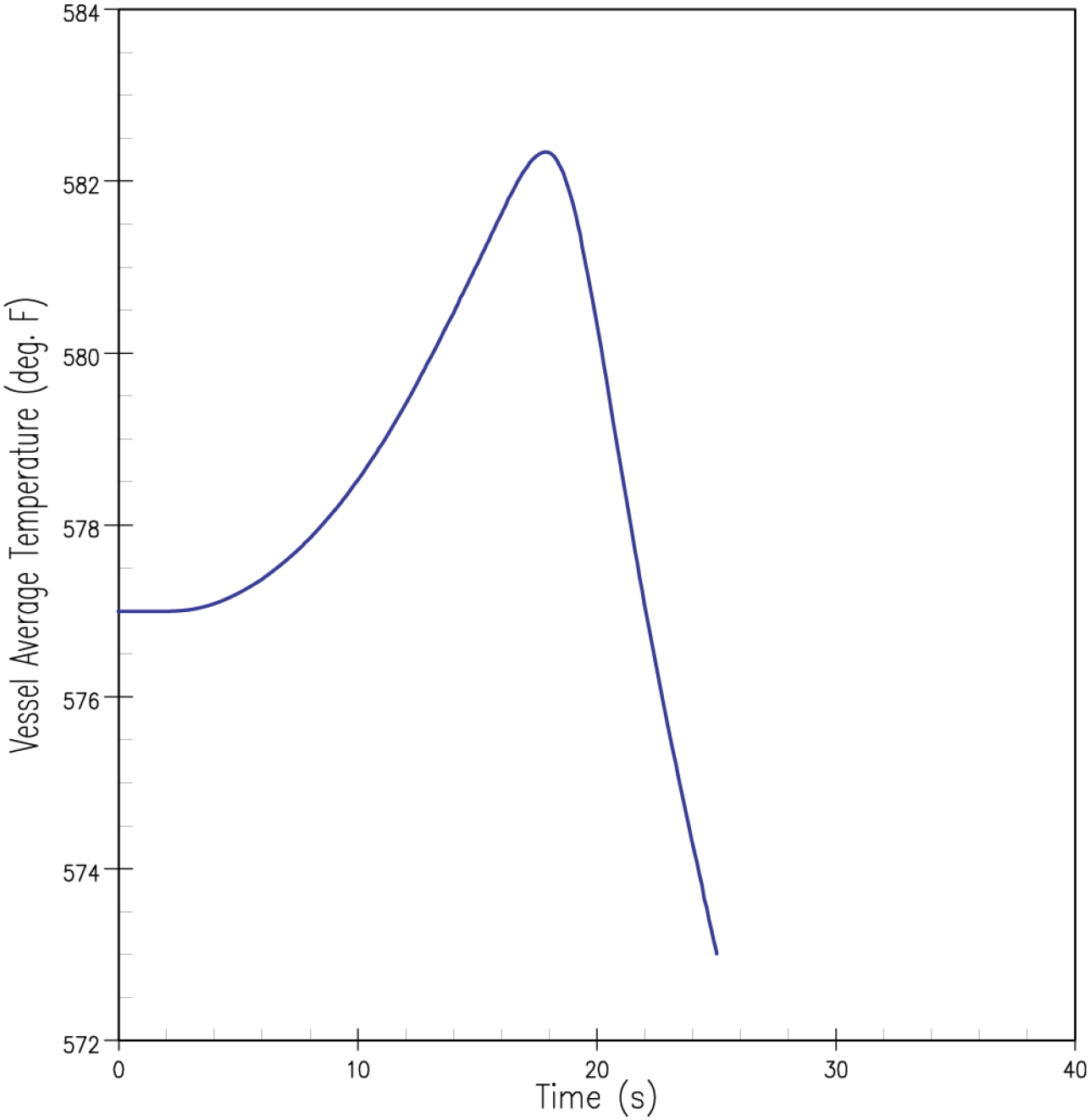
Figure 15.4.1-8
Uncontrolled CEA Withdrawal from Subcritical / Low Power (AREVA): Pressurizer Pressure vs. Time



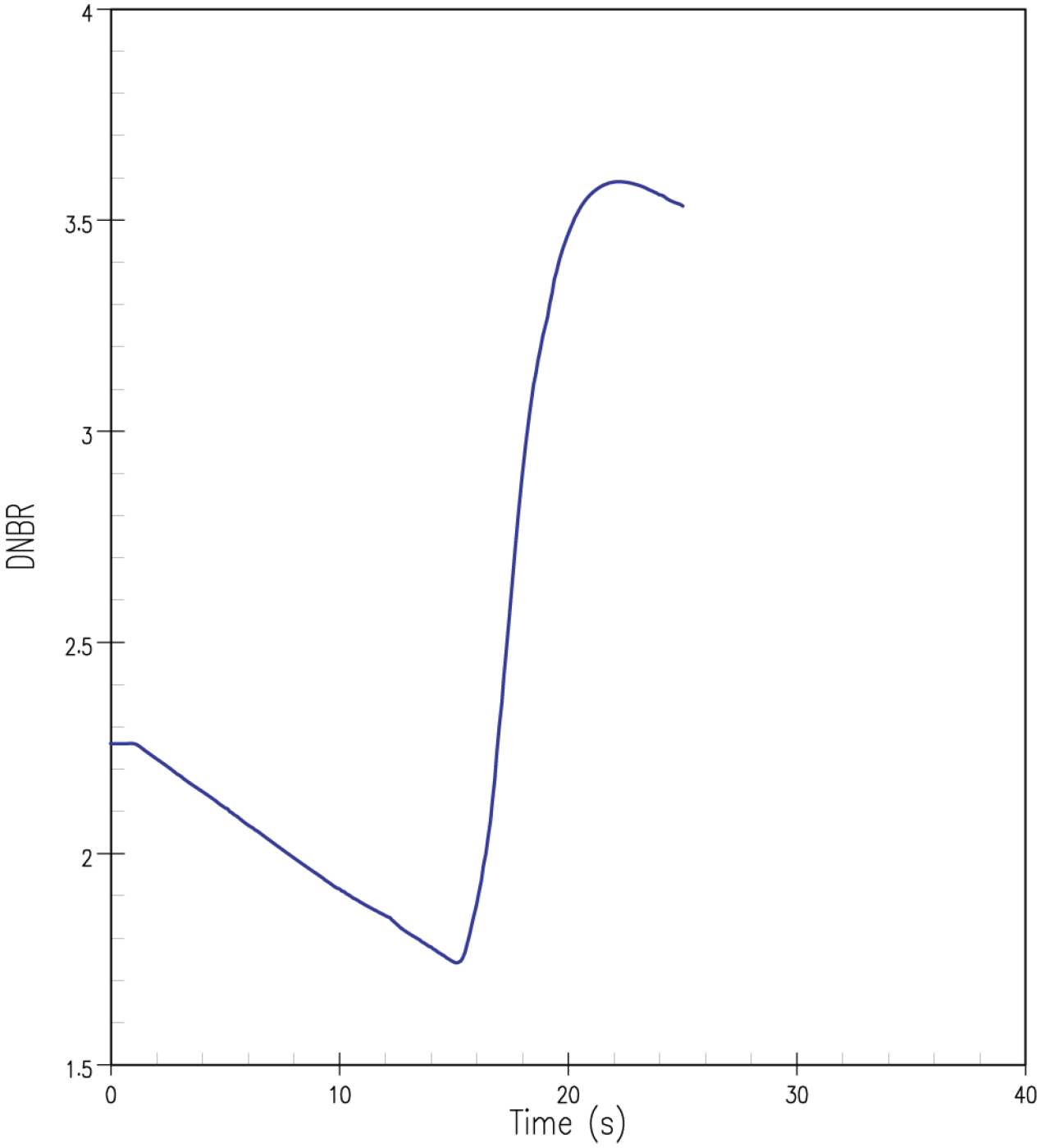
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-1 (Sheet 1 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 53 pcm/sec reactivity insertion rate, Minimum Feedback Nuclear Power vs. Time



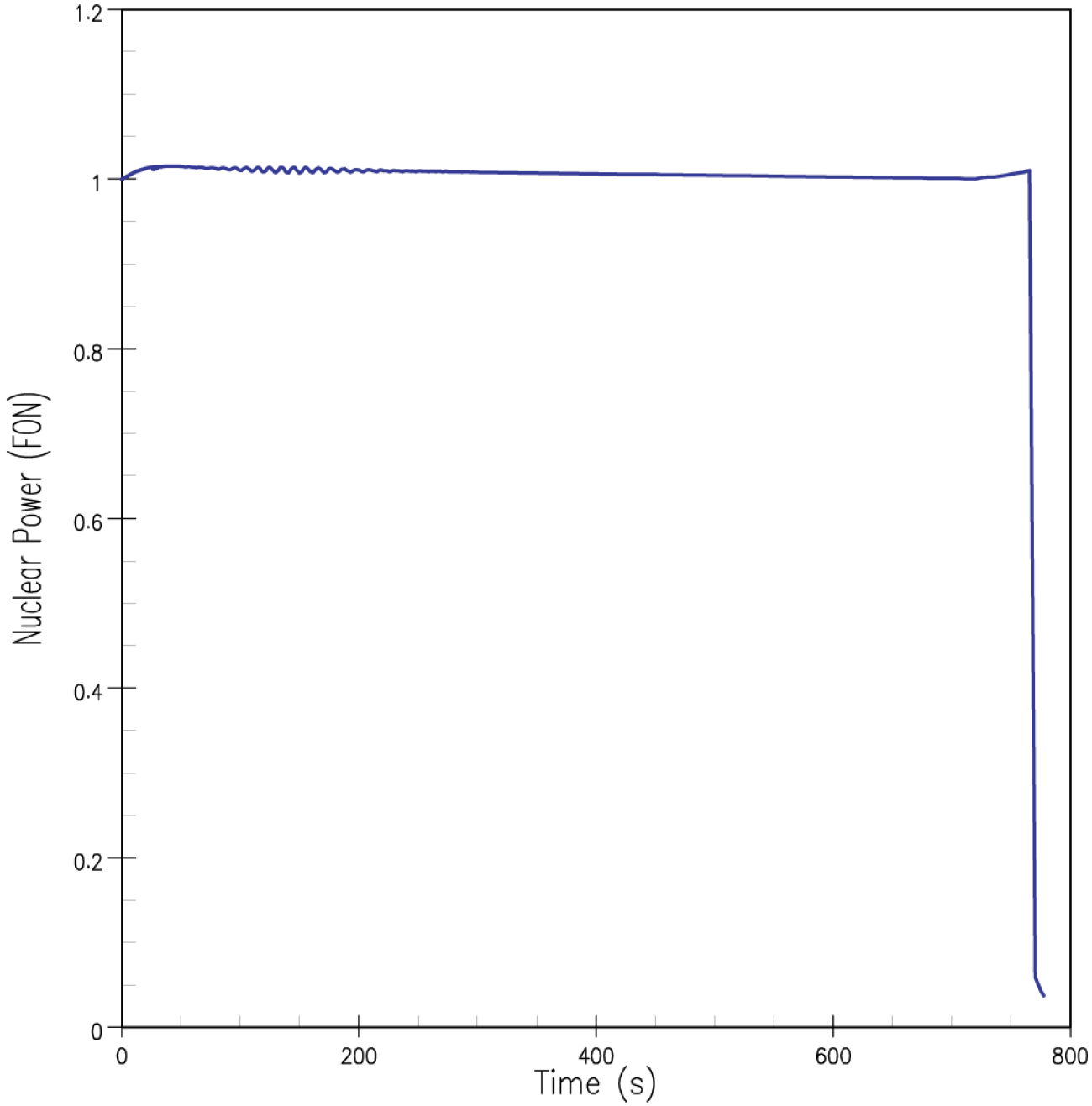
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-1 (Sheet 2 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 53 pcm/sec reactivity insertion rate, Minimum Feedback Pressurizer Pressure vs. Time



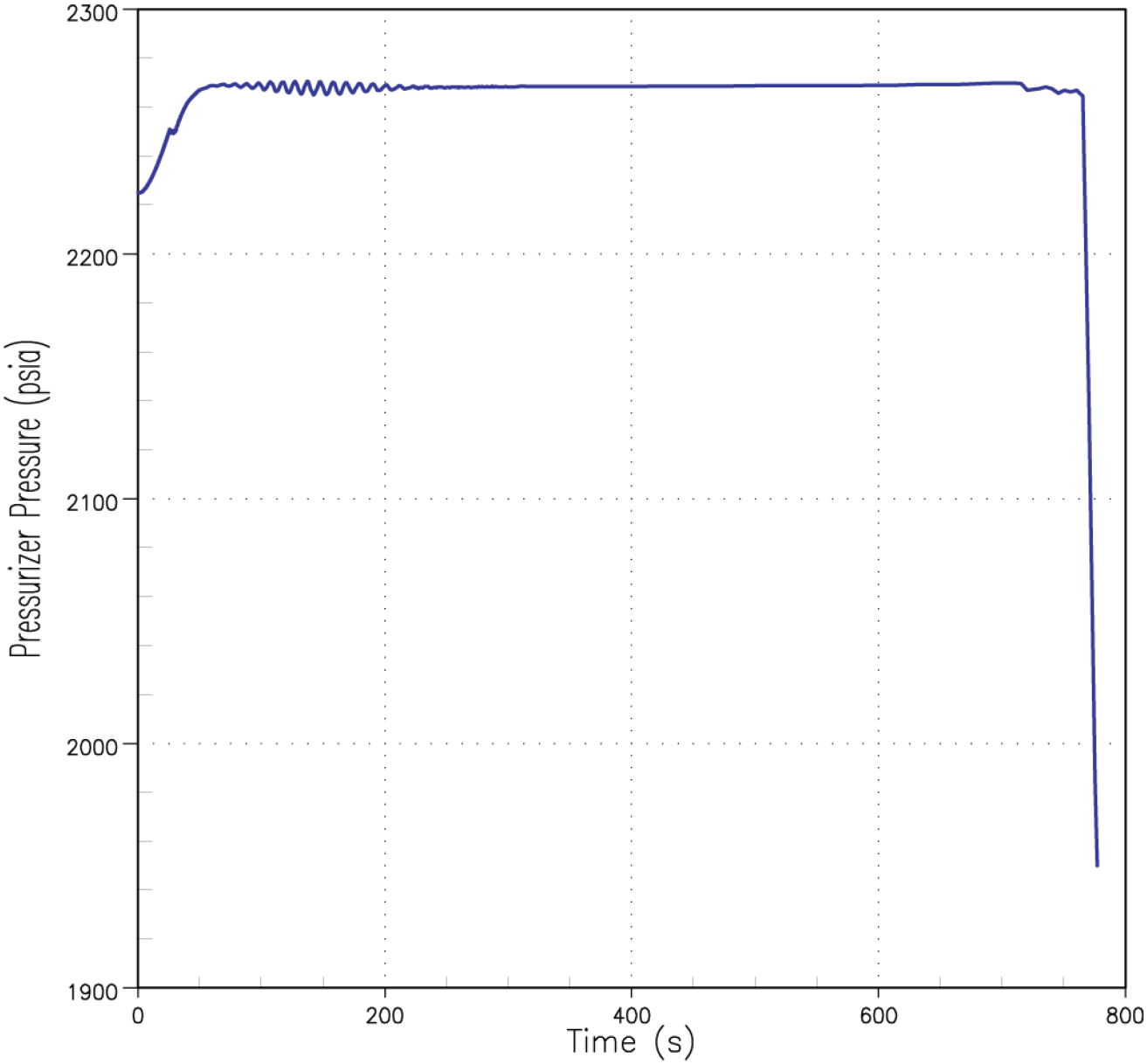
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-1 (Sheet 3 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 53 pcm/sec reactivity insertion rate, Minimum Feedback Vessel T_{avg} vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-1 (Sheet 4 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 53 pcm/sec reactivity insertion rate, Minimum Feedback DNBR vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-2 (Sheet 1 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 2 pcm/sec reactivity insertion rate, Maximum Feedback Nuclear Power vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-2 (Sheet 2 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 2 pcm/sec reactivity insertion rate, Maximum Feedback Pressurizer Pressure vs. Time

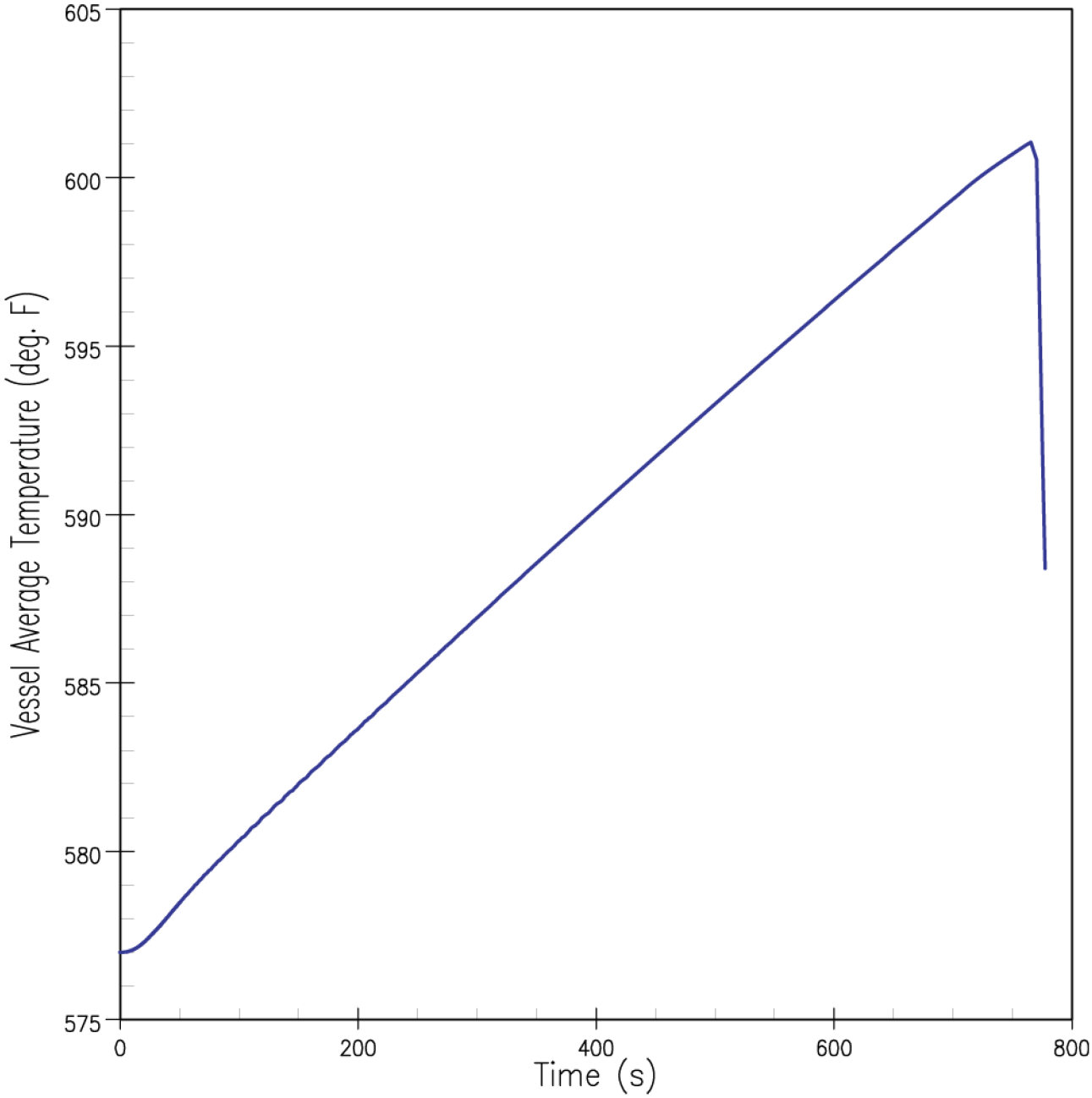


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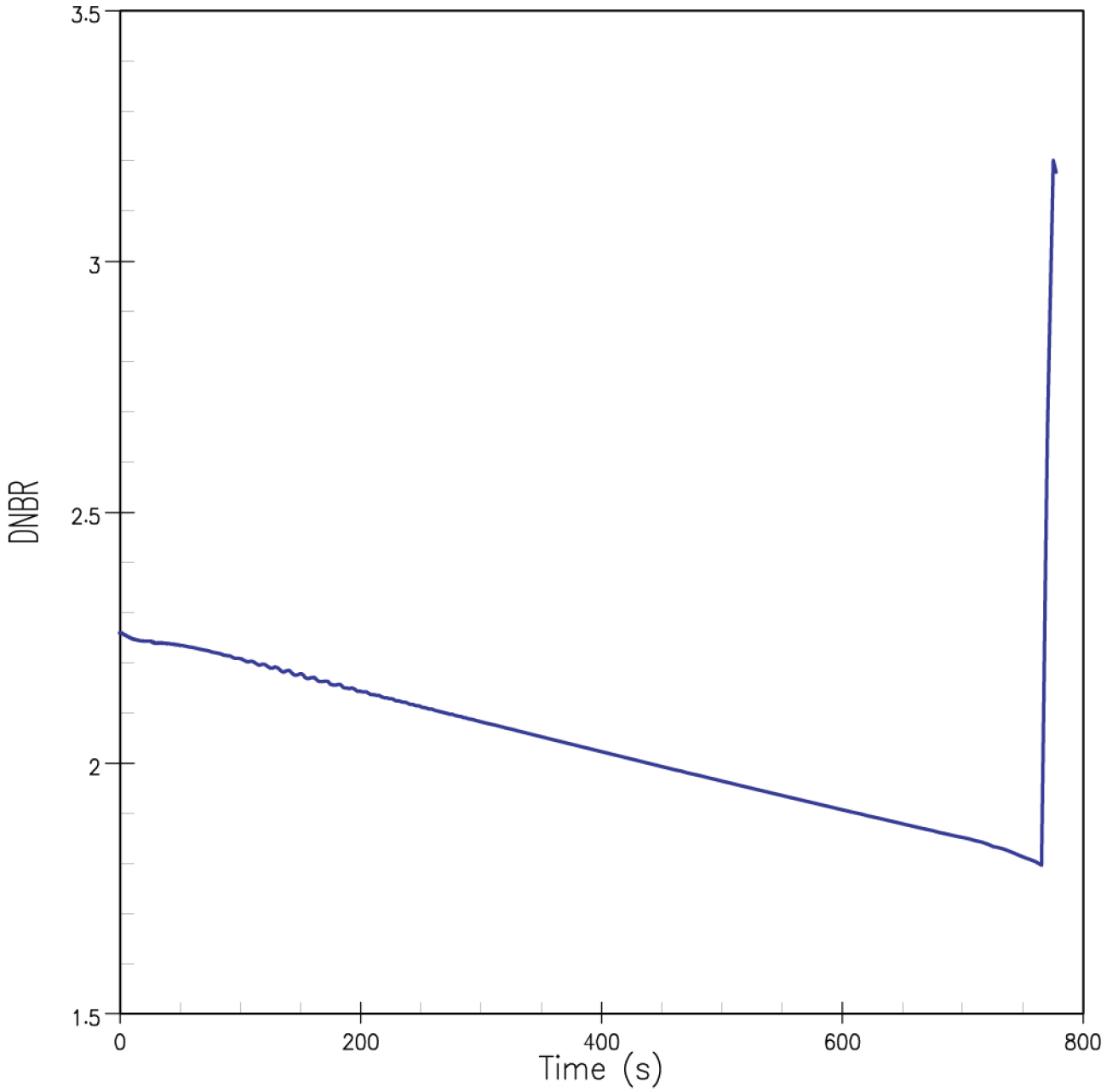
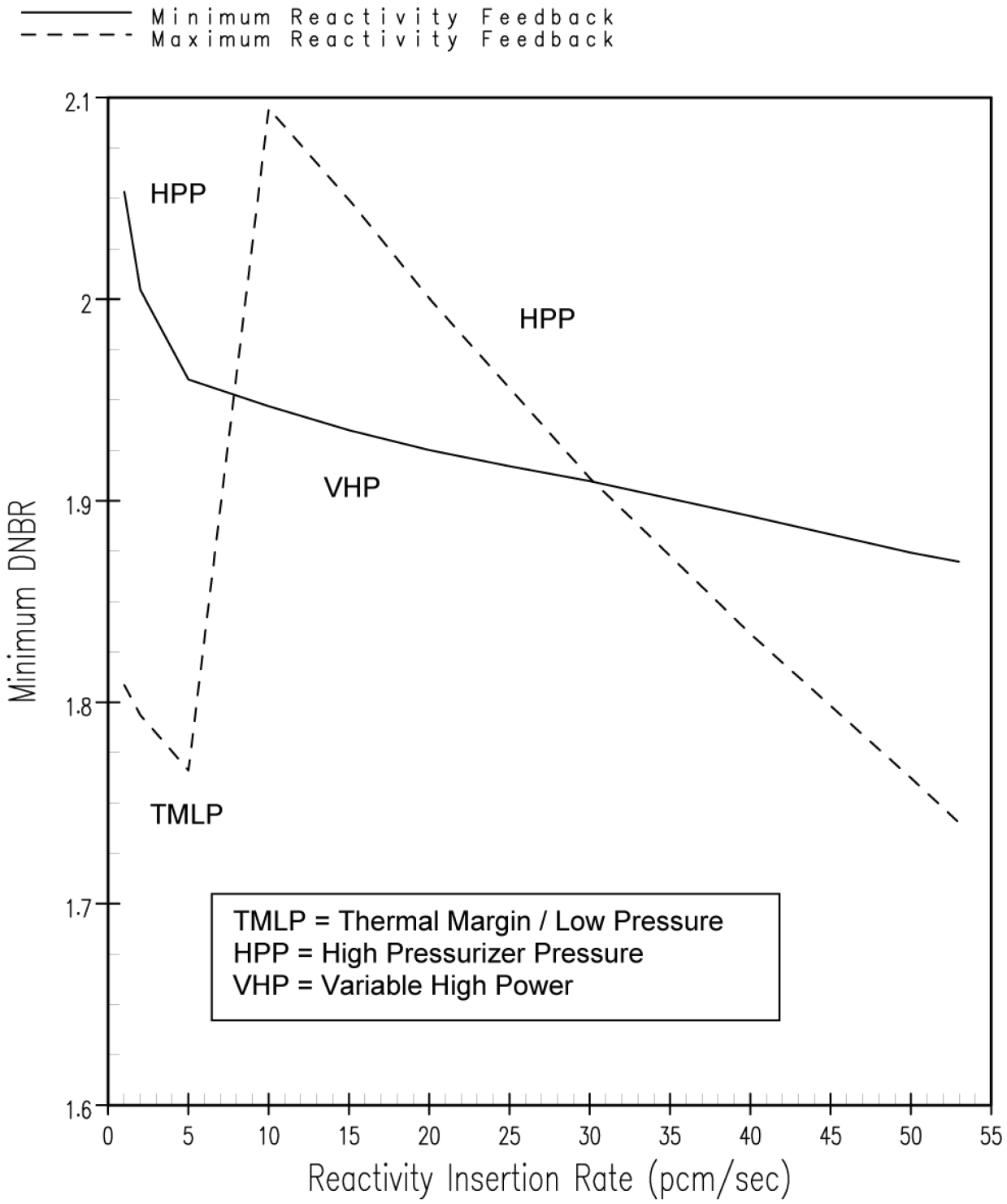
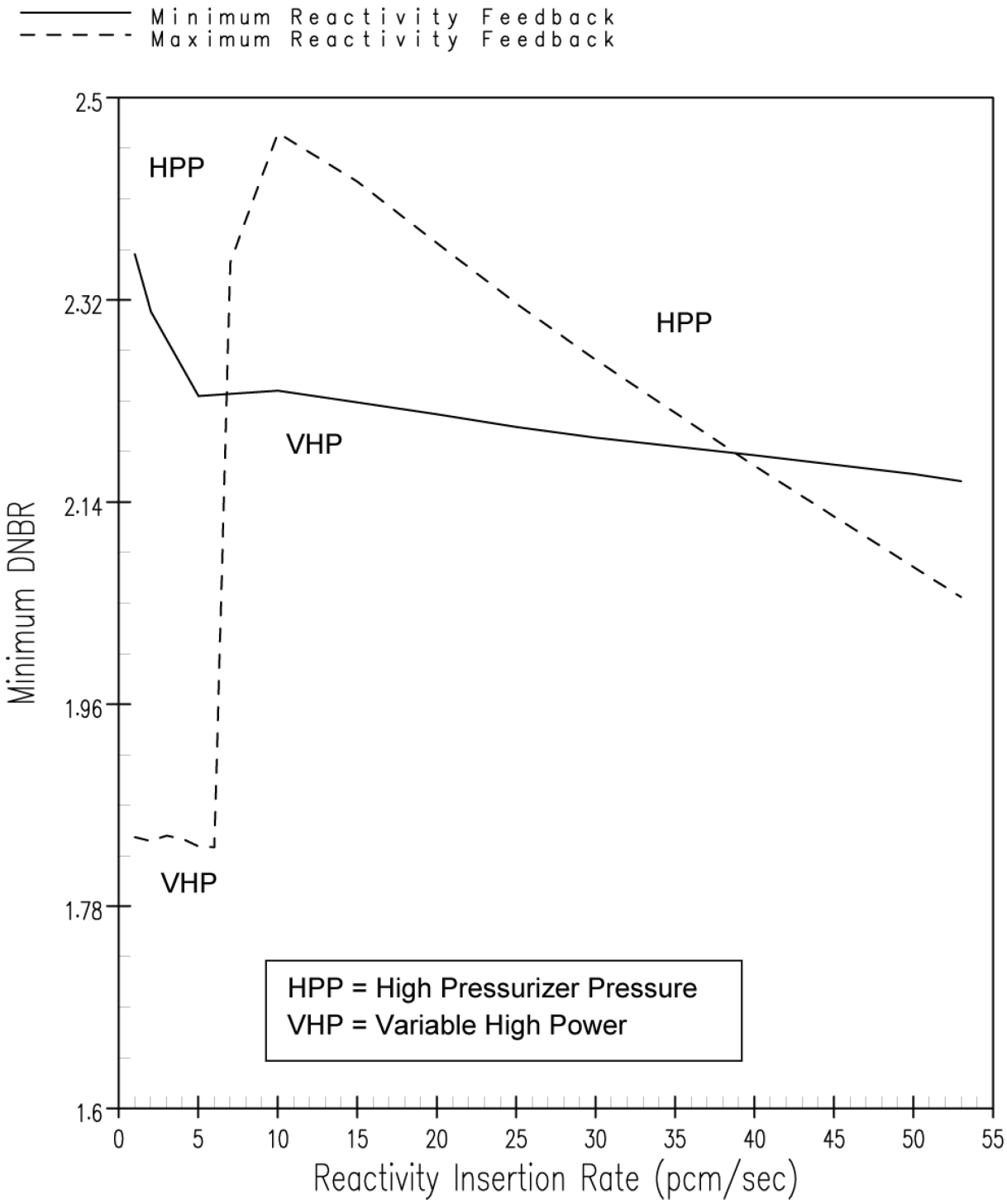
FIGURE 15.4.2-2 (Sheet 3 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 2 pcm/sec reactivity insertion rate, Maximum Feedback Vessel T_{avg} vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-2 (Sheet 4 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power, 2 pcm/sec reactivity insertion rate, Maximum Feedback DNBR vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-3 (Sheet 1 of 4) Uncontrolled CEA Bank Withdrawal at Power 100% Power DNBR vs. Reactivity Insertion Rate



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-3 (Sheet 2 of 4) Uncontrolled CEA Bank Withdrawal at Power 65% Power DNBR vs. Reactivity Insertion Rate

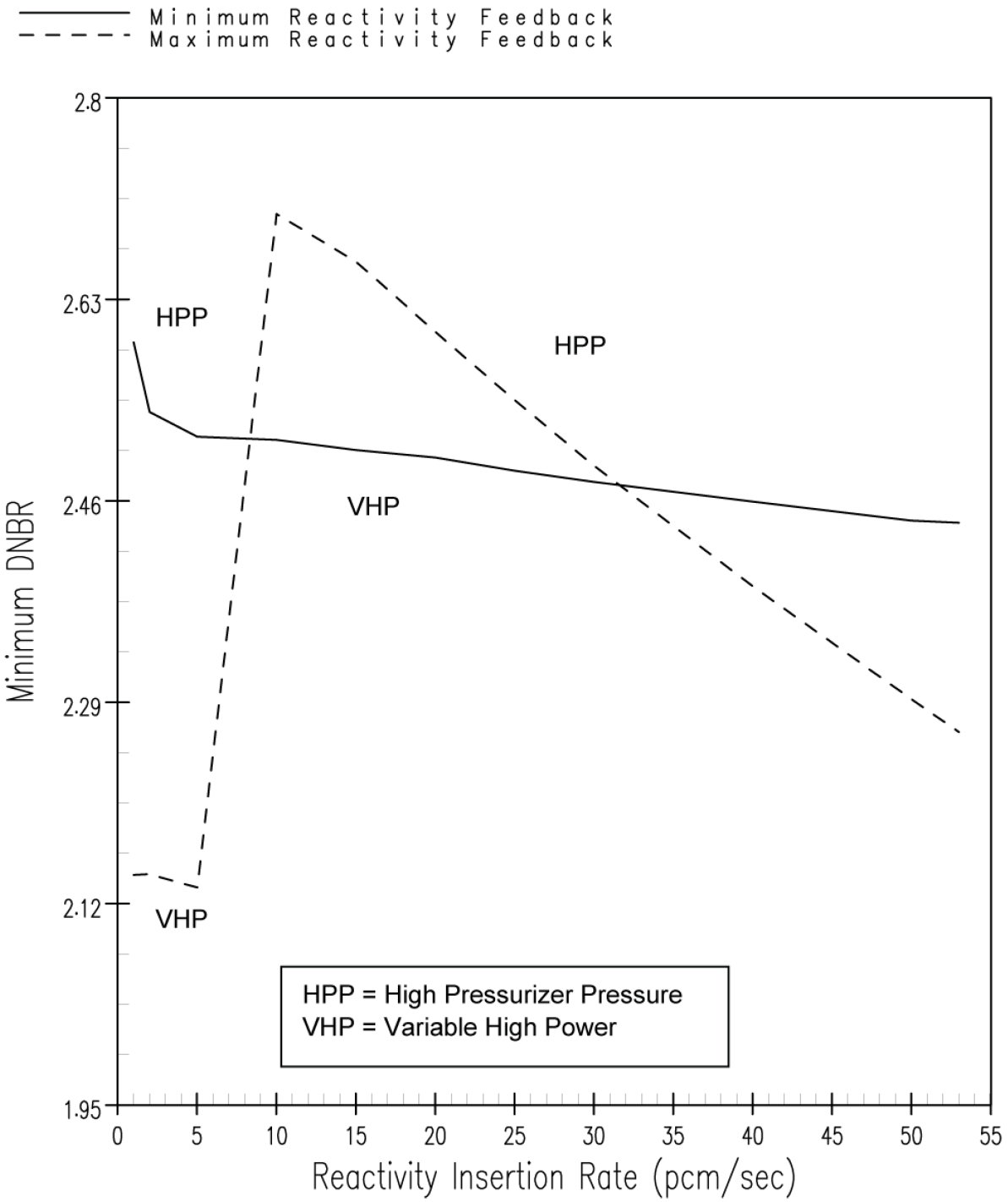


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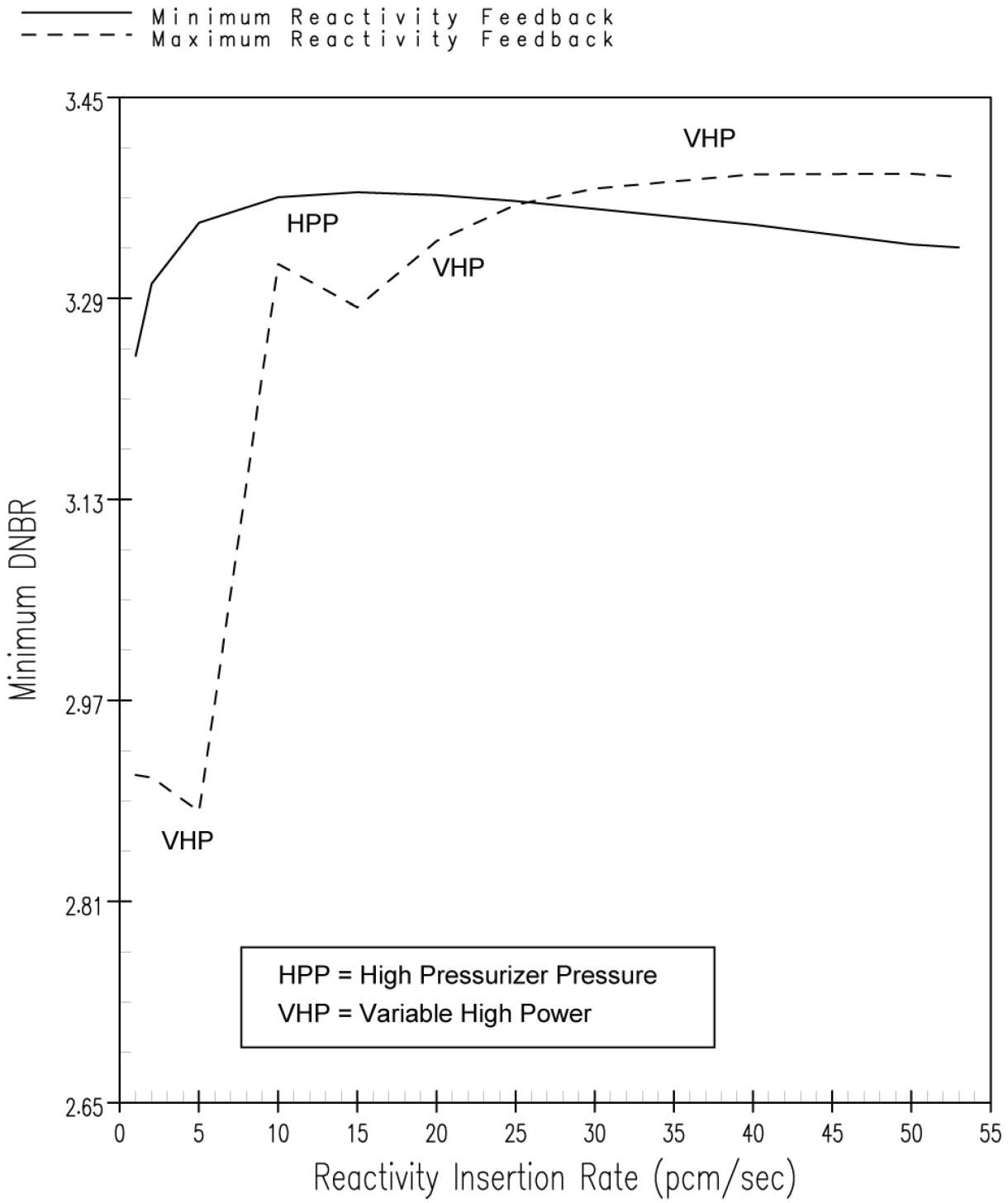
FIGURE 15.4.2-3 (Sheet 3 of 4) Uncontrolled CEA Bank Withdrawal at Power 50% Power DNBR vs. Reactivity Insertion Rate



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.2-3 (Sheet 4 of 4) Uncontrolled CEA Bank Withdrawal at Power 20% Power DNBR vs. Reactivity Insertion Rate

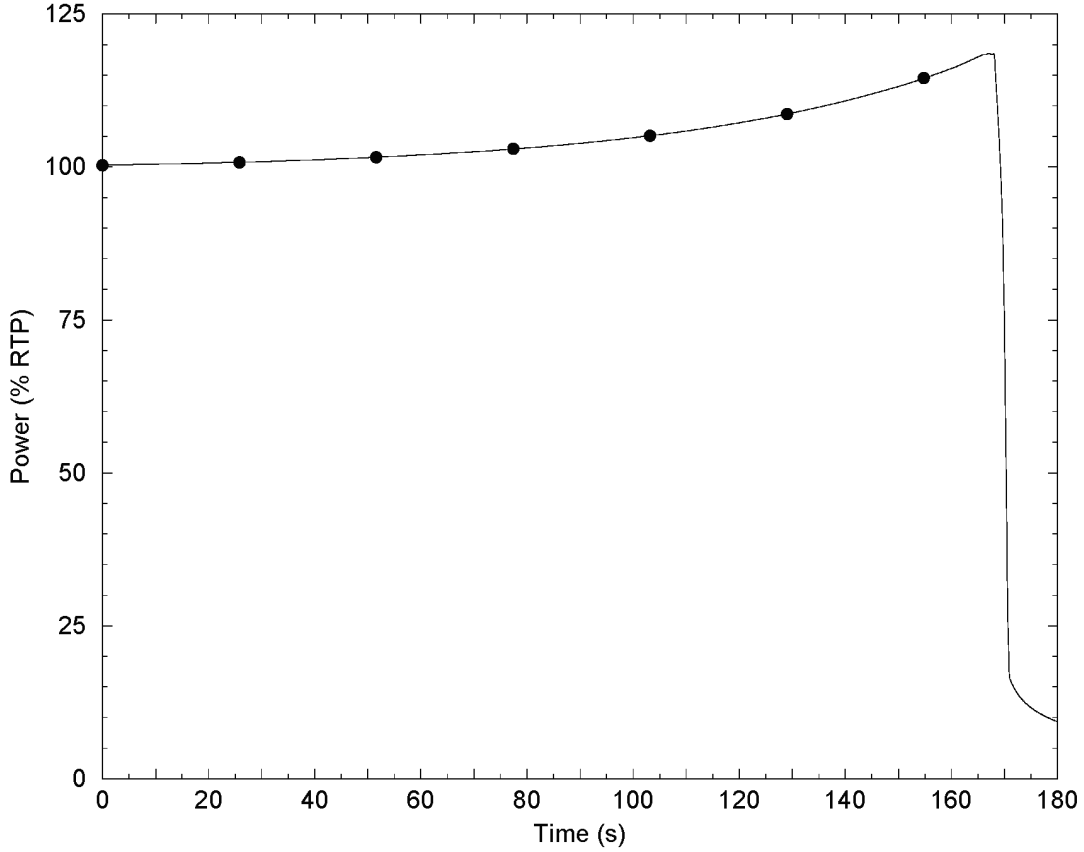


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Figure 15.4.2-4
Uncontrolled CEA Withdrawal at BOC Full Power, 0.08 pcm/sec (AREVA SAFDLs): Reactor Power vs. Time

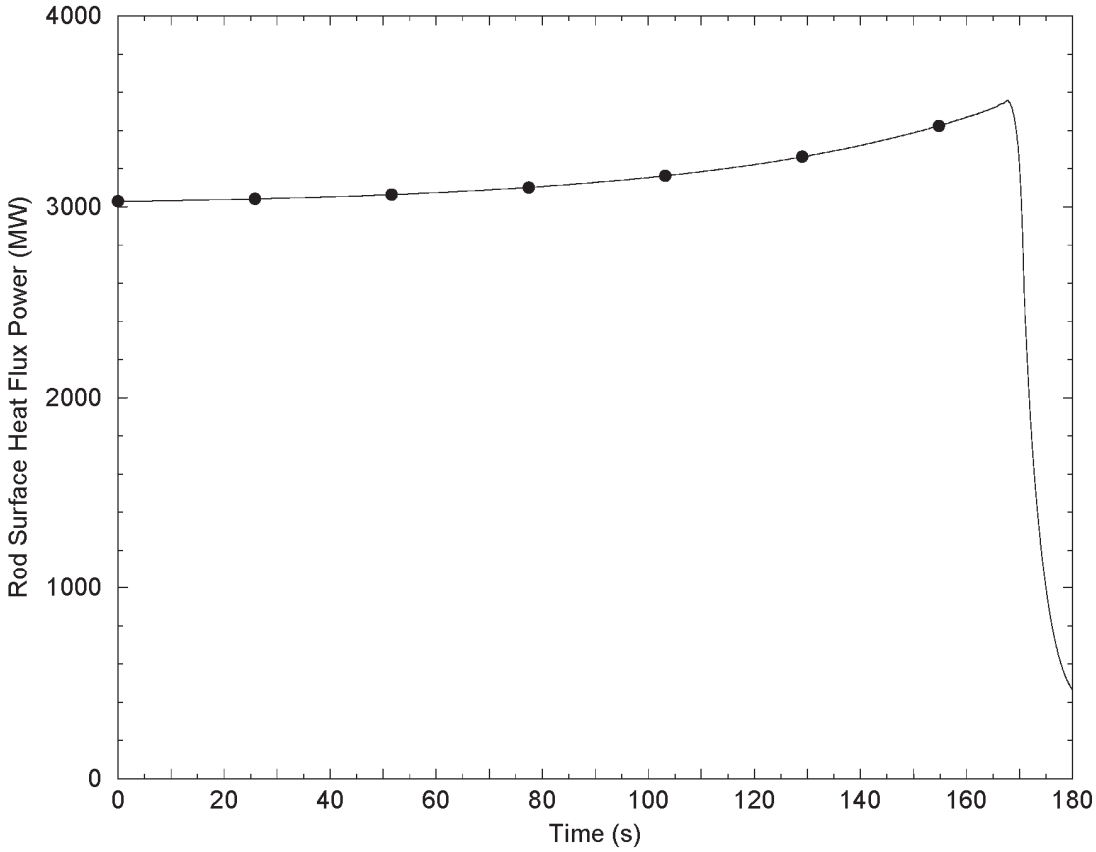

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Figure 15.4.2-5
Uncontrolled CEA Withdrawal at BOC Full Power, 0.08 pcm/sec (AREVA SAFDLs): Total Core Heat Flux Power vs. Time

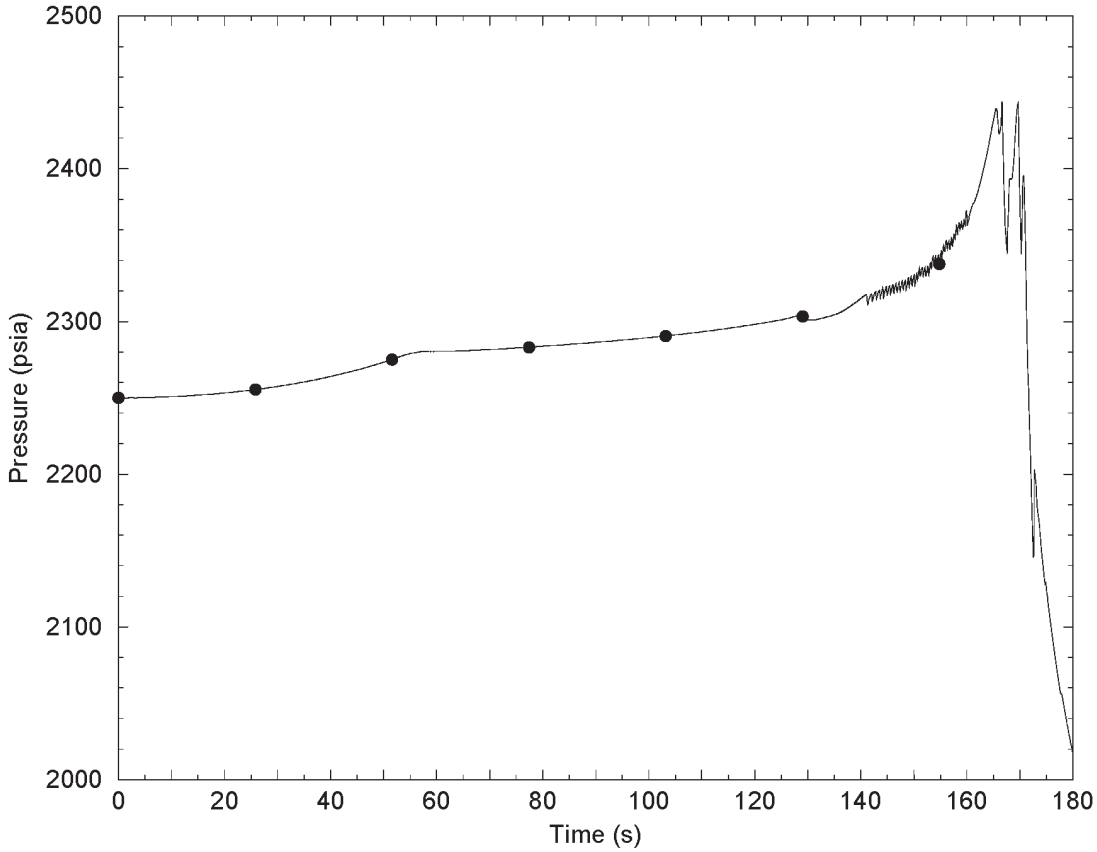

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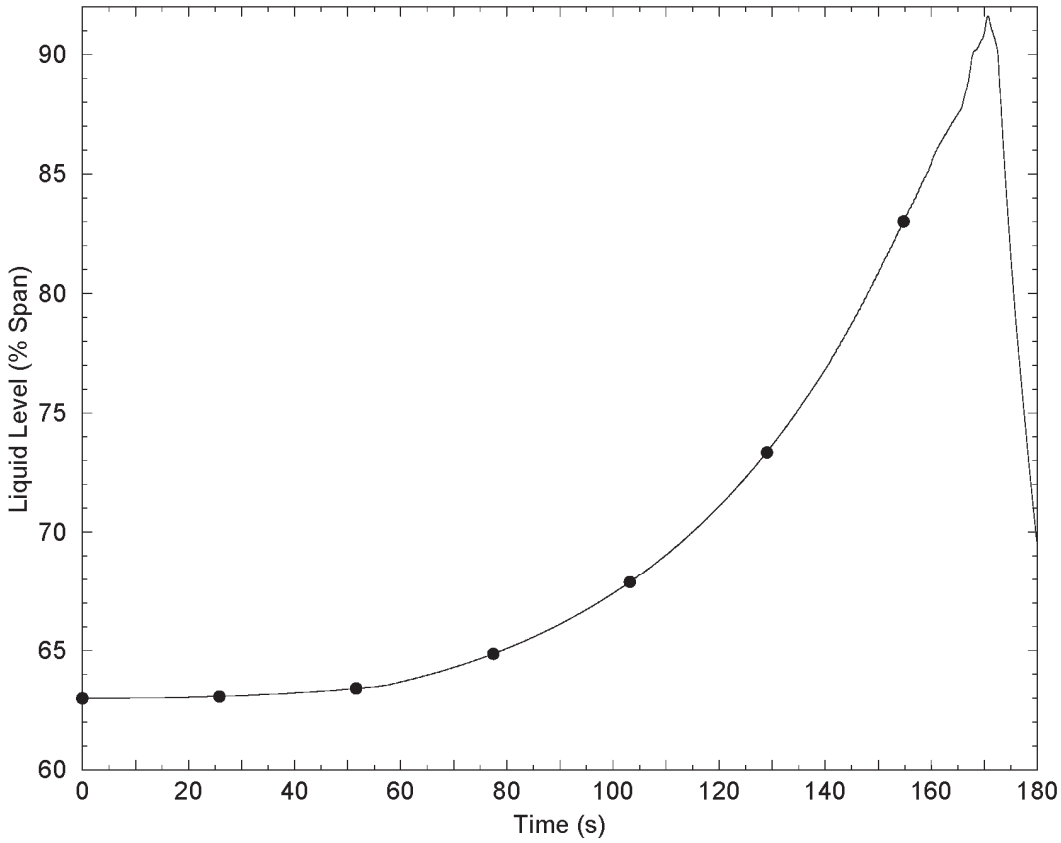
Figure 15.4.2-6
Uncontrolled CEA Withdrawal at BOC Full Power, 0.08 pcm/sec (AREVA SAFDLs): Pressurizer Pressure vs. Time



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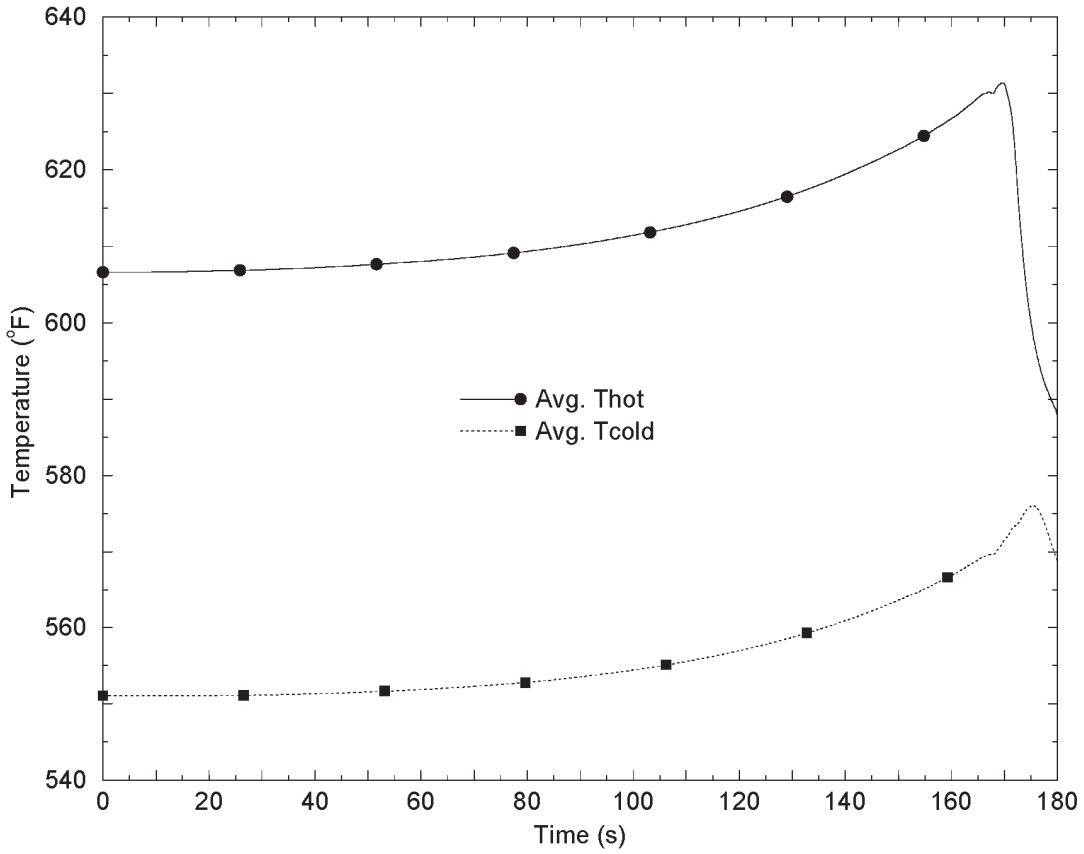
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.4.2-7
Uncontrolled CEA Withdrawal at BOC Full Power, 0.08 pcm/sec (AREVA SAFDLs): Pressurizer Liquid Level vs. Time



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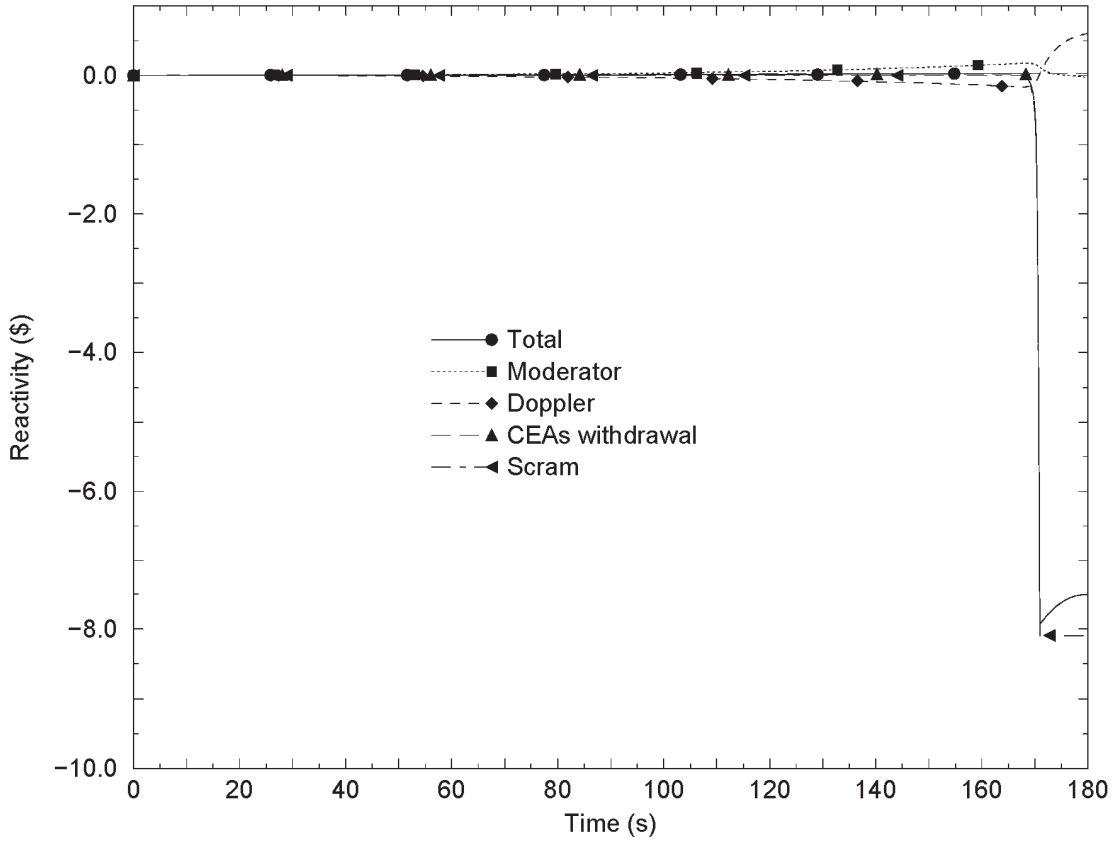
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

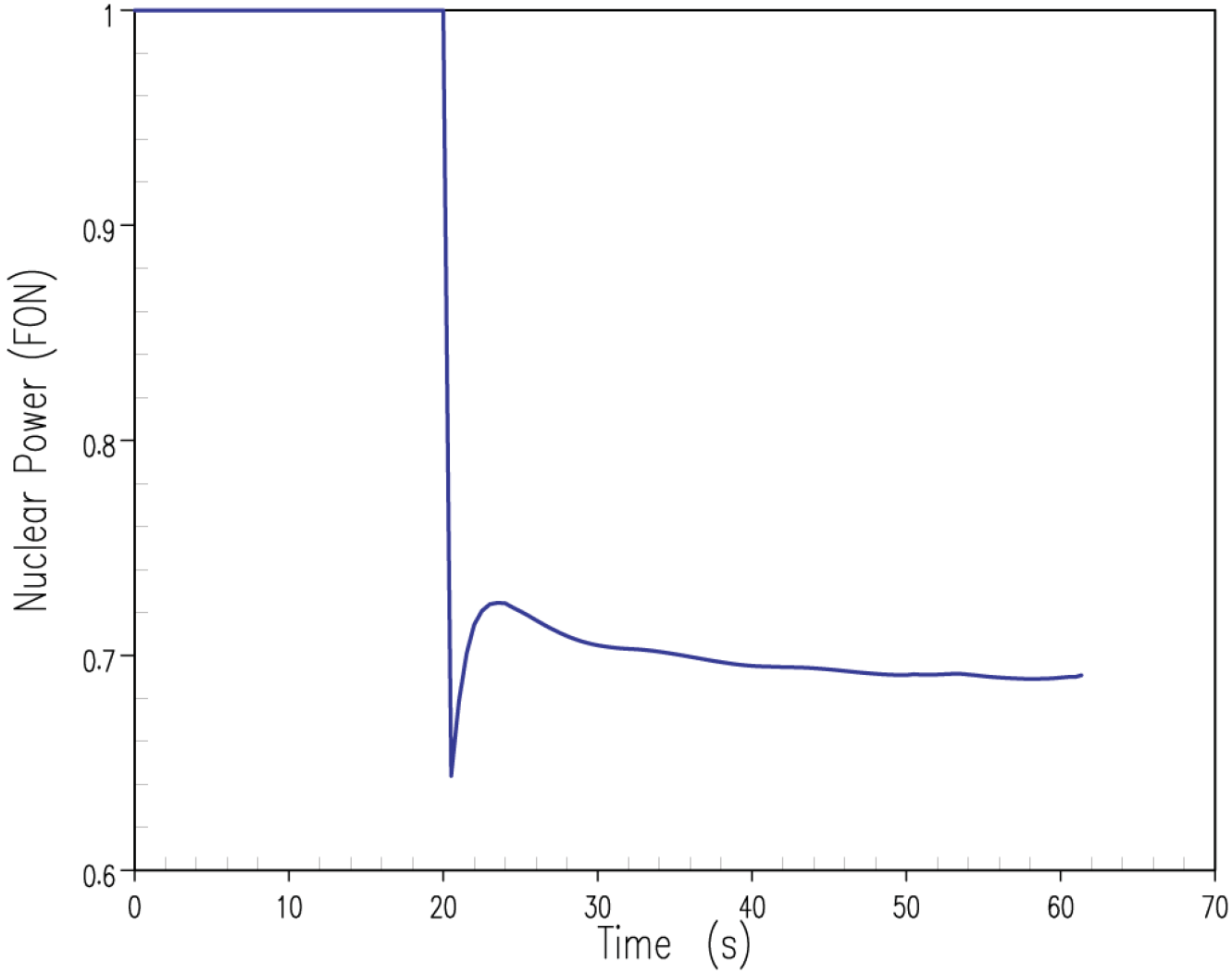
Figure 15.4.2-8
Uncontrolled CEA Withdrawal at BOC Full Power, 0.08 pcm/sec (AREVA SAFDLs): RCS Loop Temperatures vs. Time



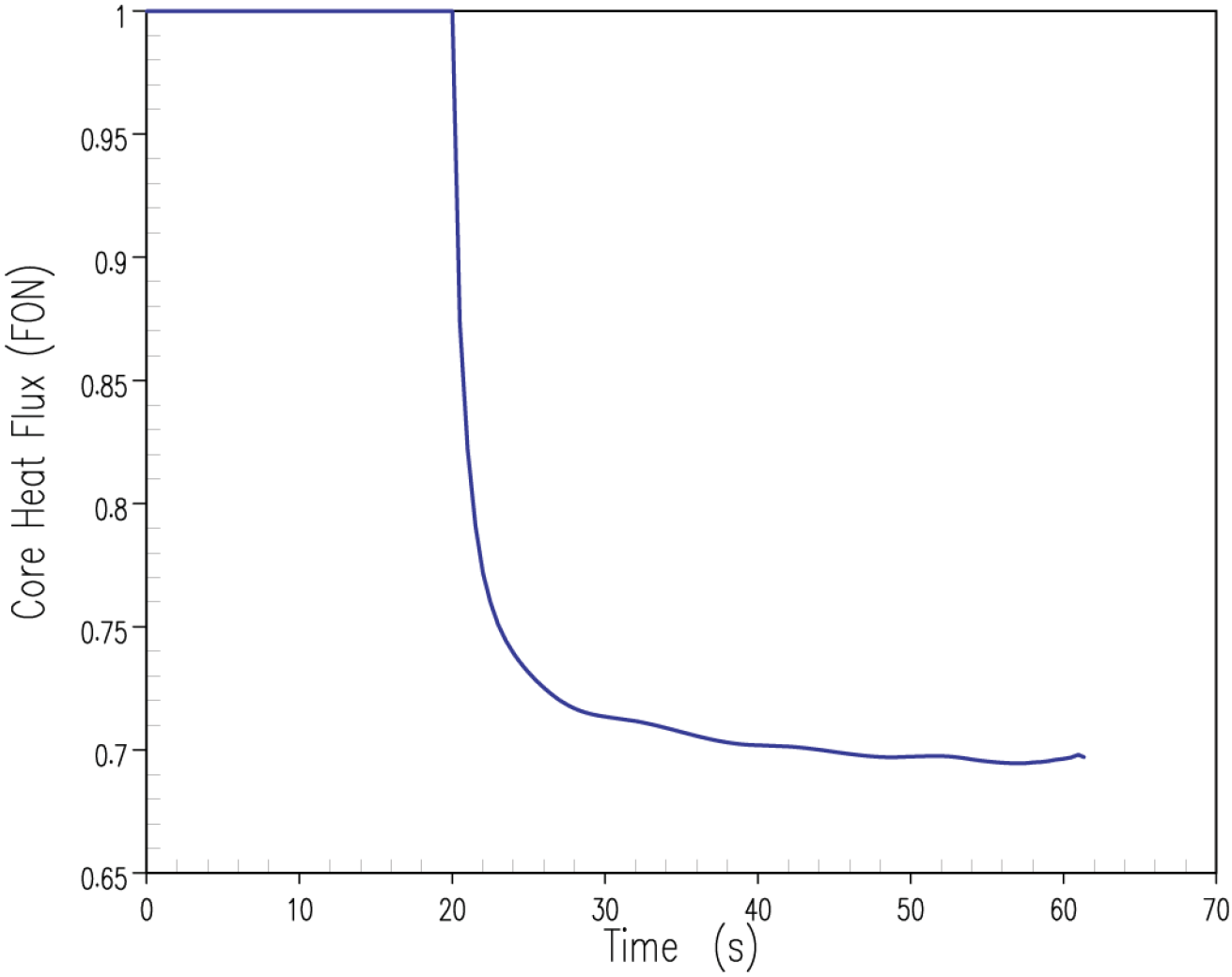
EC287528

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

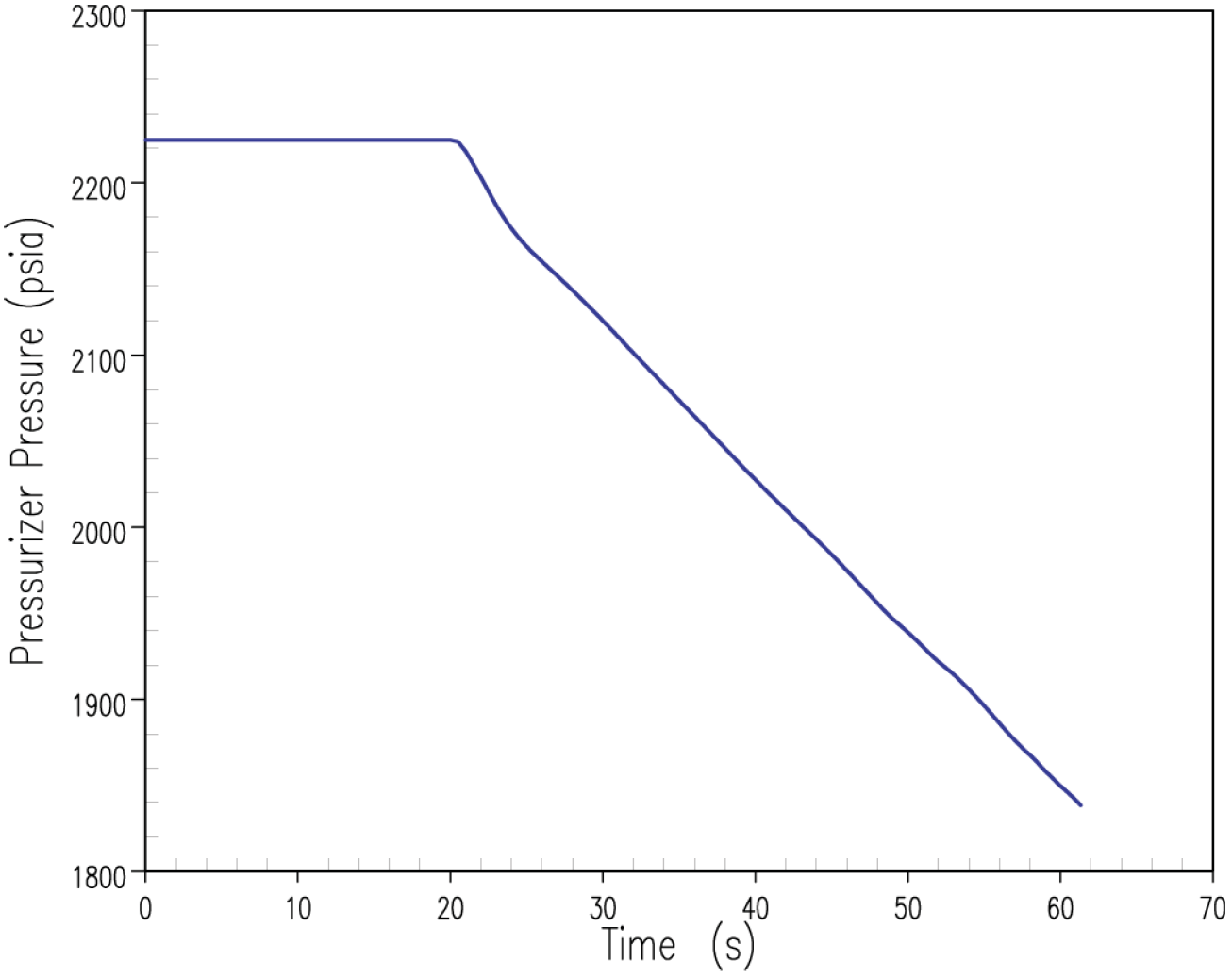
Figure 15.4.2-9
Uncontrolled CEA Withdrawal at BOC Full Power, 0.08 pcm/sec (AREVA SAFDLs): Reactivity Feedback vs. Time



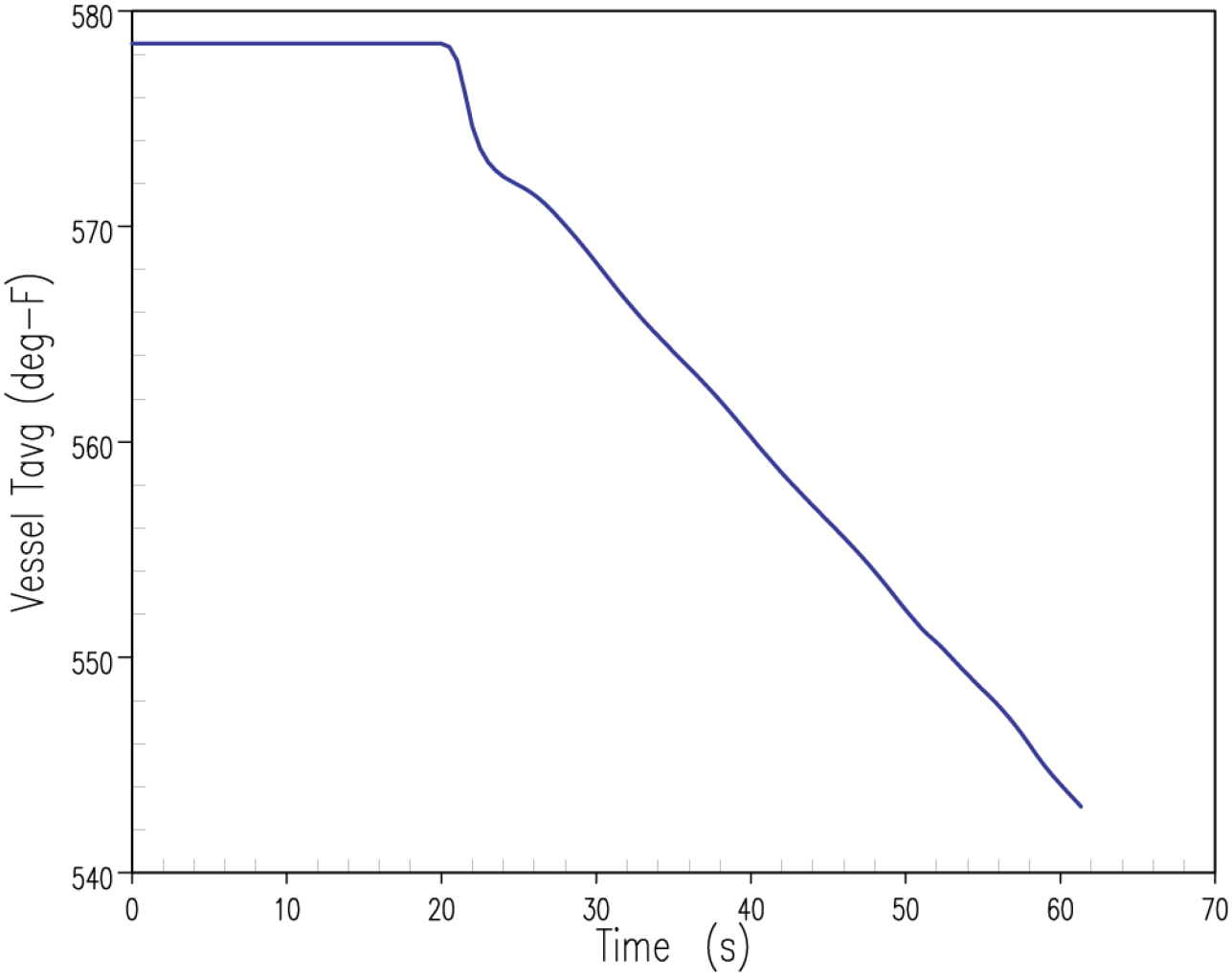
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-1 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of 0 pcm/ºF Nuclear Power versus Time



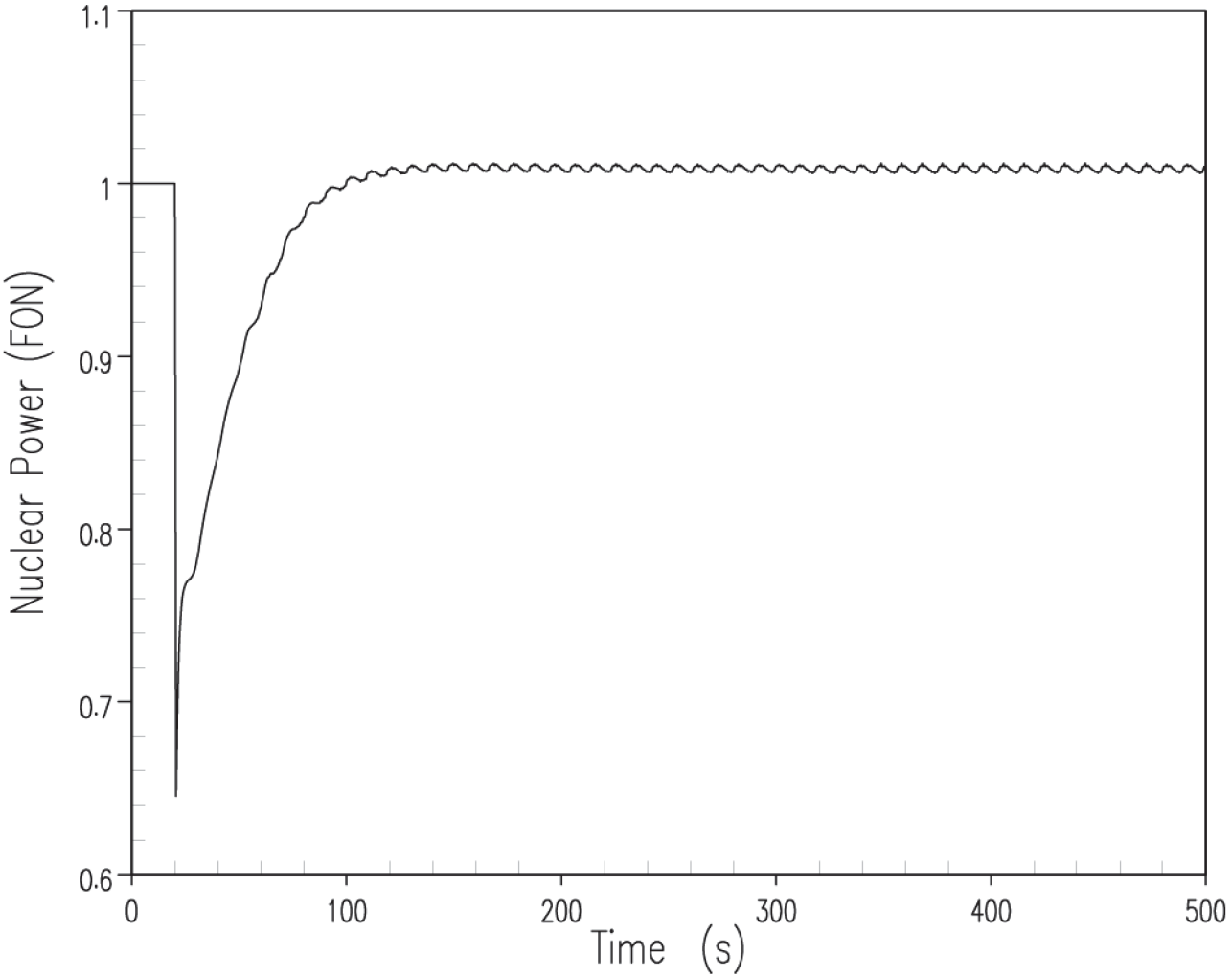
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-2 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of 0 pcm/ºF Core Heat Flux versus Time



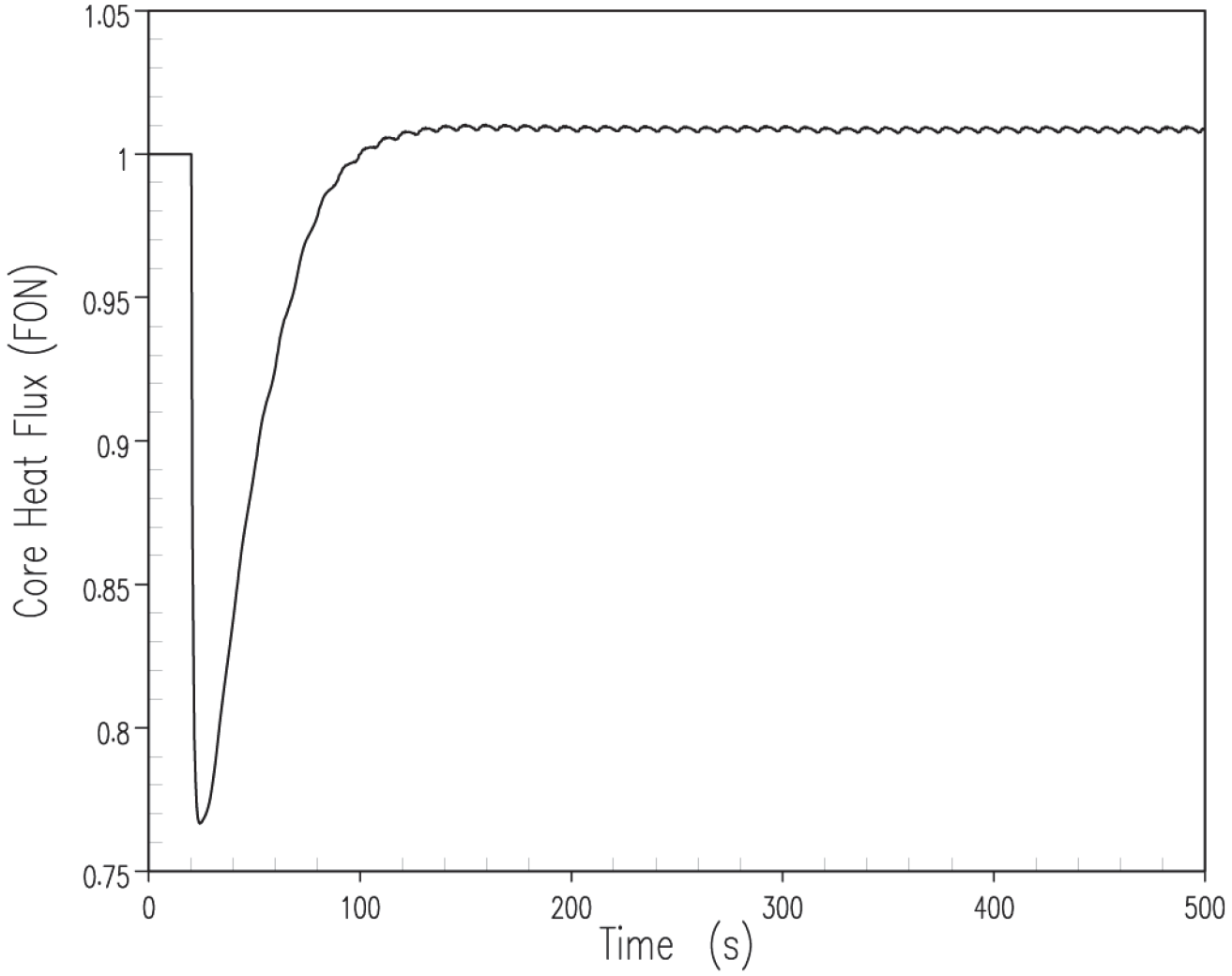
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-3 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of 0 pcm/ºF Pressurizer Pressure vs. Time



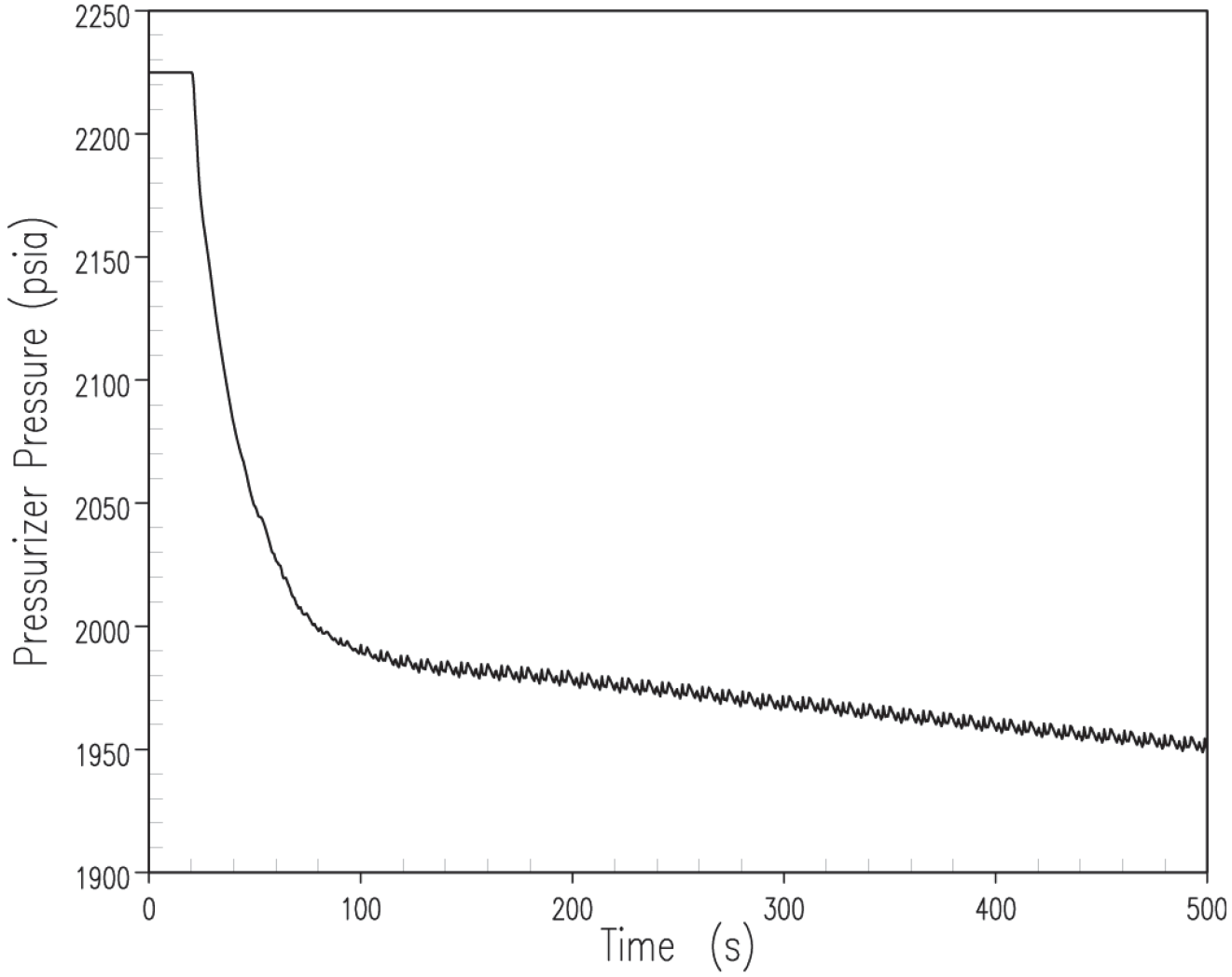
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-4 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of 0 pcm/ºF Vessel Average Temperature vs. Time



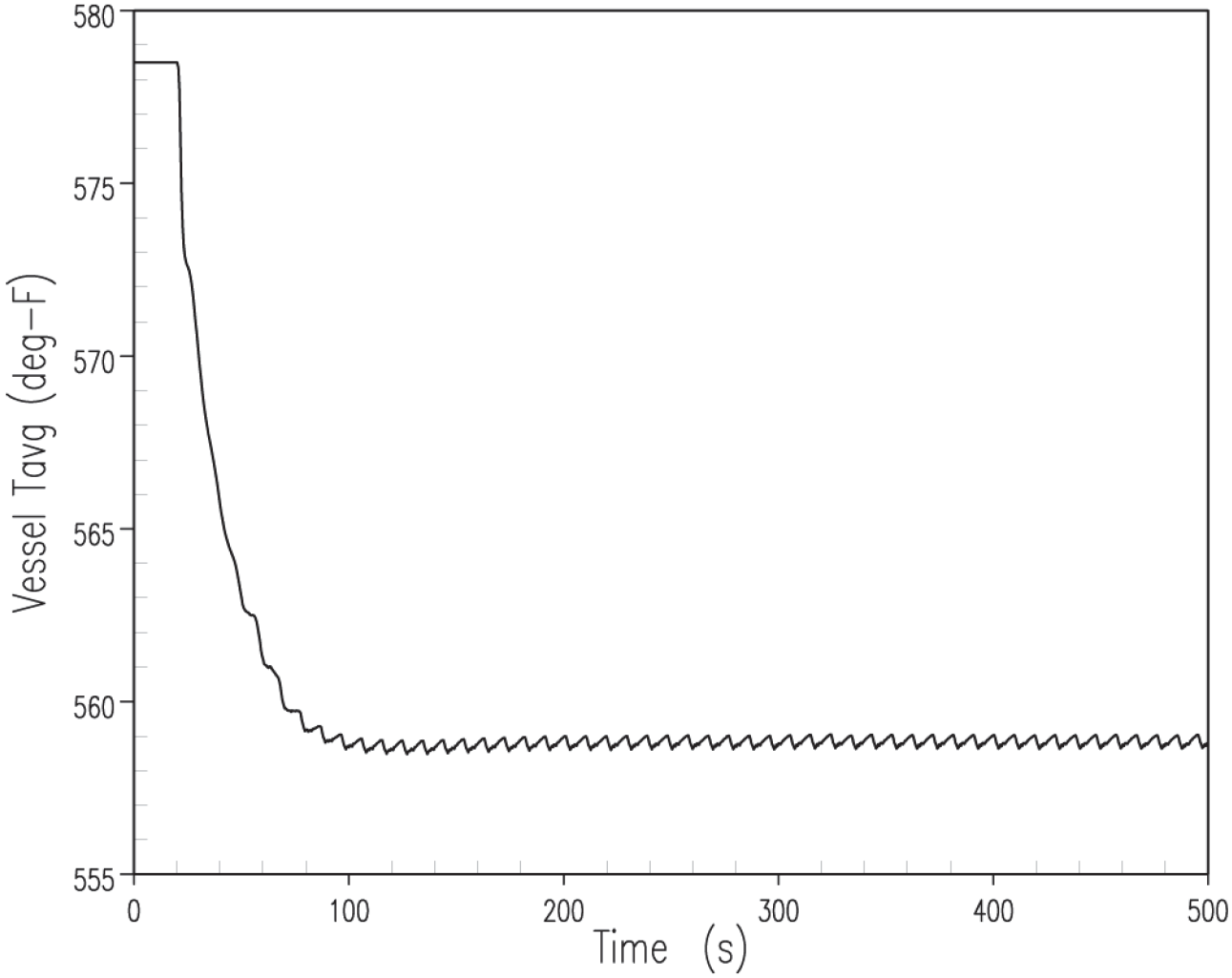
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-5 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of -25 pcm/ºF Nuclear Power vs. Time



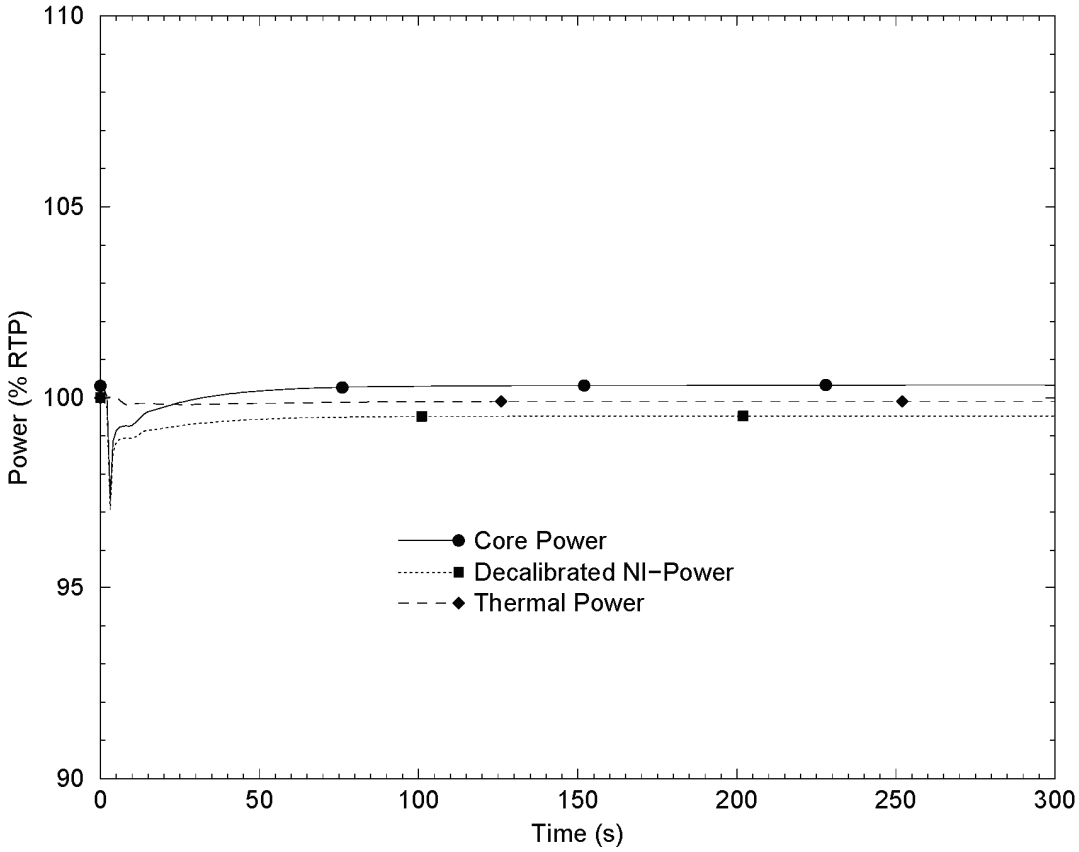
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-6 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of -25 pcm/ºF Core Heat Flux versus Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-7 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of -25 pcm/ºF Pressurizer Pressure versus Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.3-8 Representative Transient Response to a CEA Drop Worth of 500 pcm at a MTC of -25 pcm/ºF Vessel Average Temperature versus Time



EC287528

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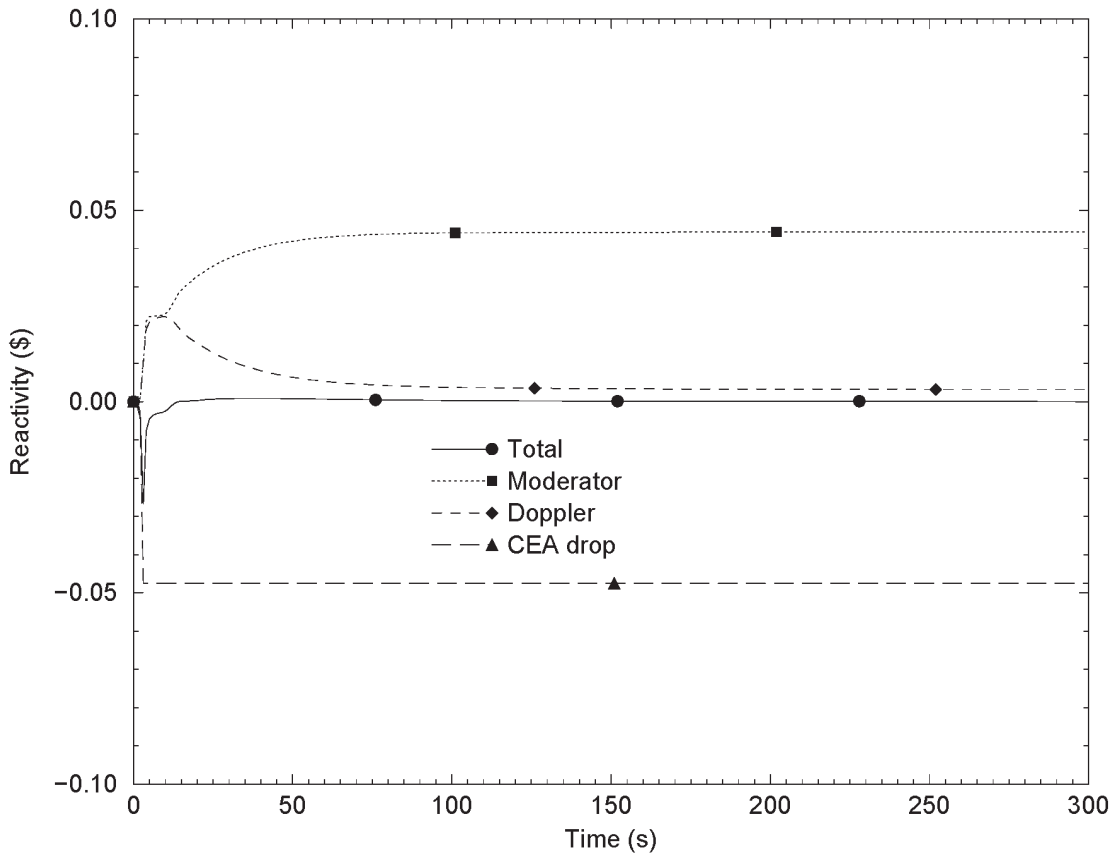
ST. LUCIE PLANT UNIT 2

Figure 15.4.3-9
25-pcm-Worth CEA Drop (AREVA):
Reactor Power vs. Time



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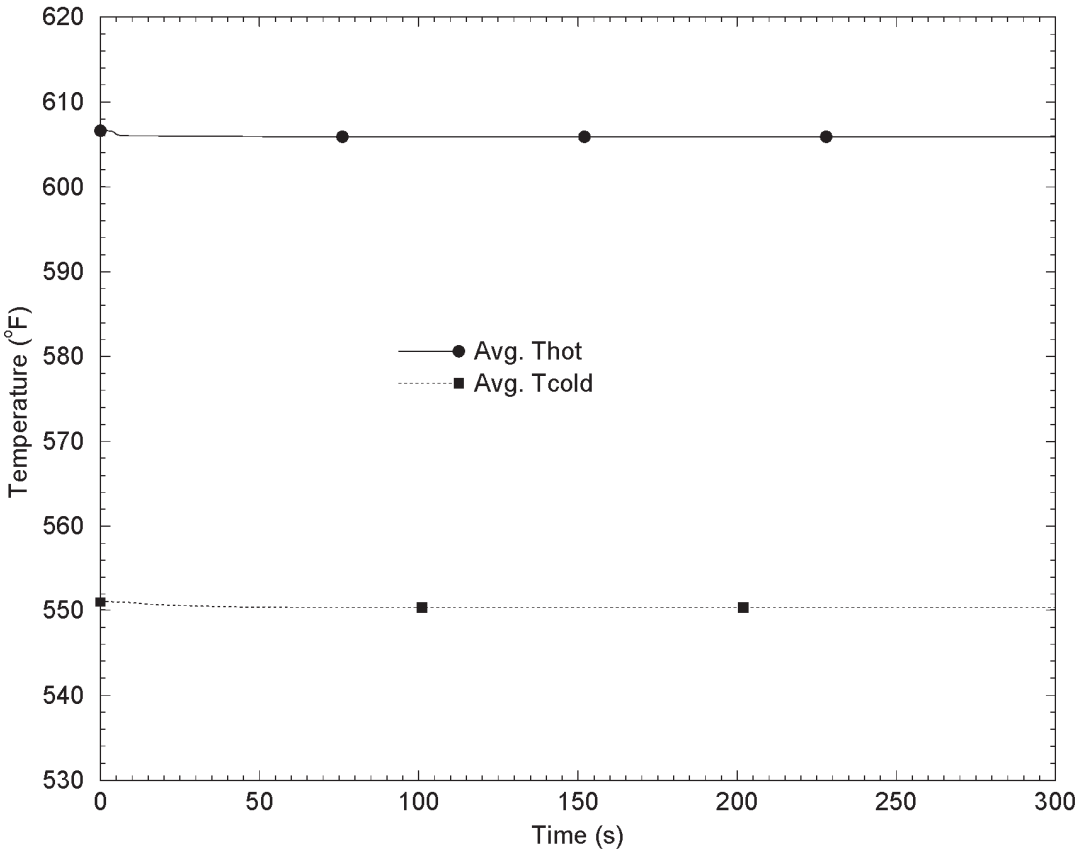
ST. LUCIE PLANT UNIT 2

Figure 15.4.3-10
25-pcm-Worth CEA Drop (AREVA):
Reactivity Feedback vs. Time



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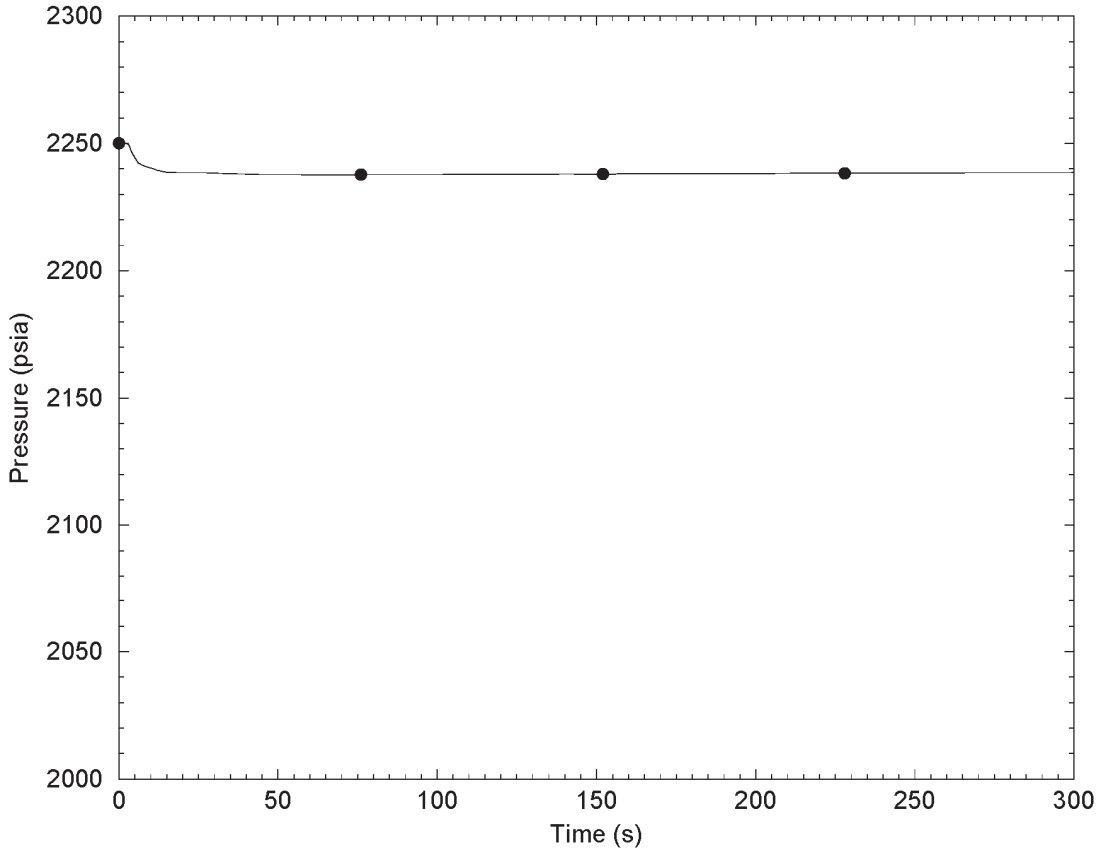
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

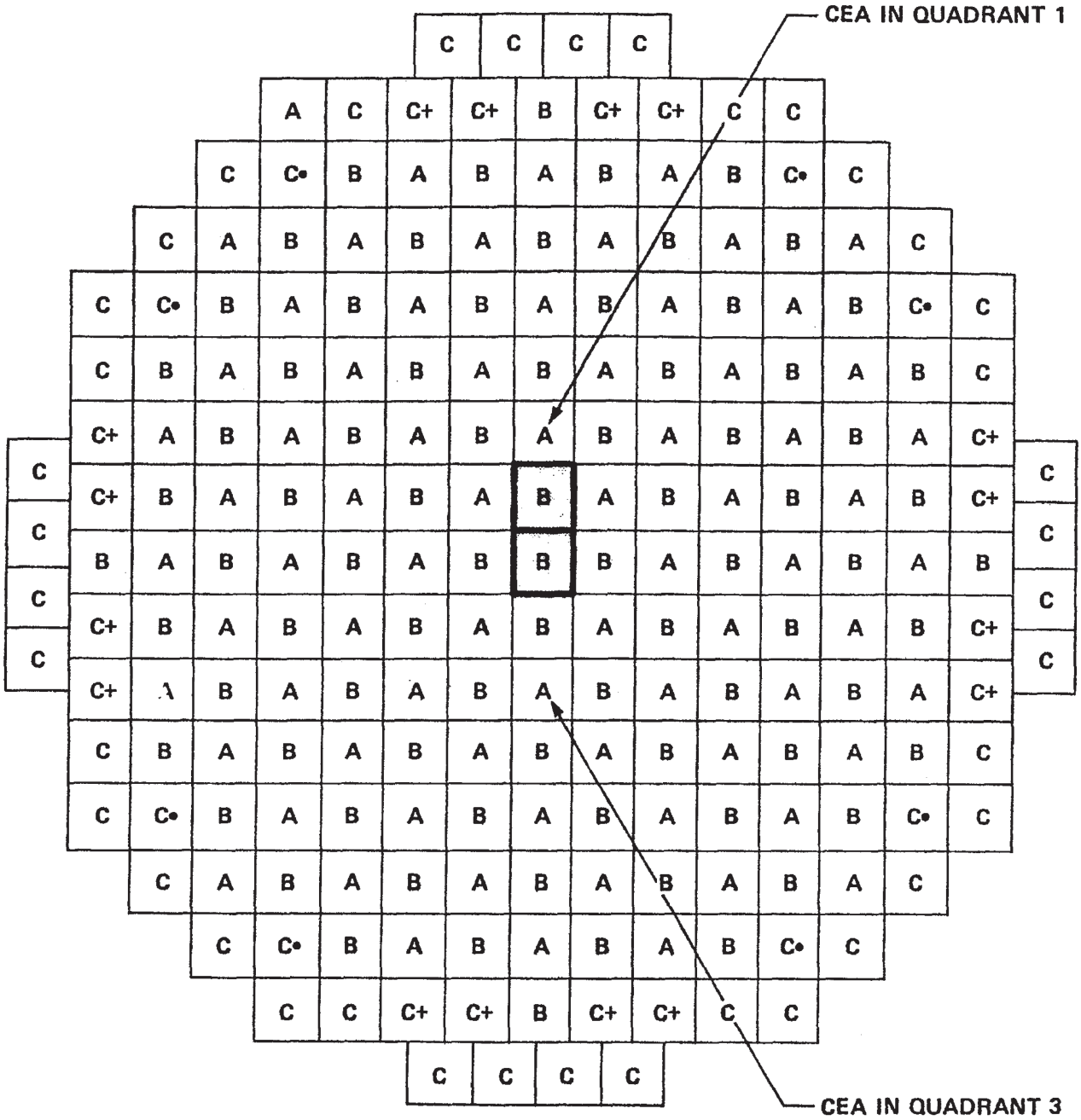
Figure 15.4.3-11
25-pcm-Worth CEA Drop (AREVA):
RCS Loop Temperatures vs. Time



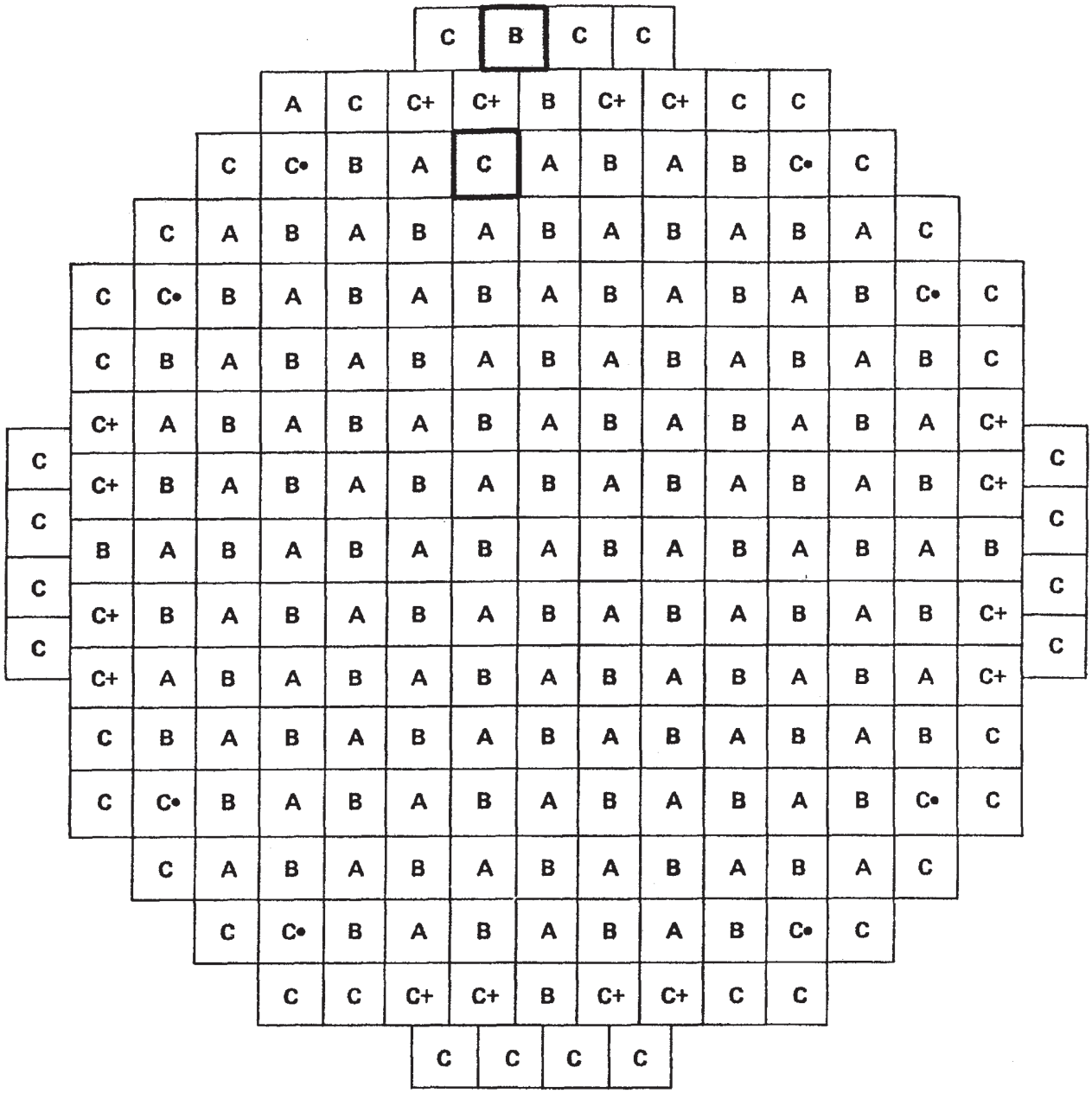
EC287528

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

Figure 15.4.3-12
25-pcm-Worth CEA Drop (AREVA):
Pressurizer Pressure vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.7-1 Loading pattern for Interchange of Type A and B Assemblies Near Core Center



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.7-2 Loading Pattern for Interchange of Type B and C Assemblies Near Core Periphery

					C 0.673	C 0.901	C 0.901	C 0.673						
			C 0.625	C 0.855	C+ 0.968	C+ 1.118	B 1.018	C+ 1.118	C+ 0.968	C 0.855	C 0.625			
		C 0.682	C• 0.980	B 0.973	A 1.014	B 1.069	A 1.052	B 1.069	A 1.014	B 0.973	C• 0.981	C 0.682		
	C 0.680	A 0.839	B 0.970	A 1.012	B 1.093	A 1.087	B 1.132	A 1.087	B 1.093	A 1.012	B 0.970	A 0.834	C 0.680	
C 0.620	C• 0.974	B 0.966	A 1.004	B 1.094	A 1.103	B 1.168	A 1.142	B 1.168	A 1.103	B 1.094	A 1.004	B 0.966	C• 0.974	C 0.620
C 0.846	B 0.963	A 1.003	B 1.087	A 1.100	B 1.179	A 1.177	B 1.231	A 1.177	B 1.179	A 1.100	B 1.087	A 1.003	B 0.963	C 0.846
C+ 0.954	A 0.999	B 1.077	A 1.086	B 1.163	A 1.170	B 1.264	A 1.276	B 1.264	A 1.170	B 1.164	A 1.086	B 1.077	A 0.999	C+ 0.954
C+ 1.099	B 1.049	A 1.064	B 1.137	A 1.136	B 1.210	A 1.238	A 1.304	A 1.238	B 1.210	A 1.137	B 1.137	A 1.064	B 1.050	C+ 1.099
B 0.999	A 1.029	B 1.102	A 1.102	B 1.166	A 1.149	B 1.171	B 1.134	B 1.171	A 1.149	B 1.166	A 1.102	B 1.102	A 1.029	B 0.999
C+ 1.095	B 1.044	A 1.056	B 1.124	A 1.114	B 1.162	A 1.114	B 1.120	A 1.114	B 1.162	A 1.114	B 1.124	A 1.056	B 1.044	C+ 1.095
C+ 0.947	A 0.989	B 1.062	A 1.064	B 1.127	A 1.107	B 1.147	A 1.110	B 1.147	A 1.108	B 1.127	A 1.064	B 1.062	A 0.989	C+ 0.947
C 0.836	B 0.950	A 0.985	B 1.061	A 1.062	B 1.120	A 1.098	B 1.137	A 1.098	B 1.120	A 1.062	B 1.061	A 0.985	B 0.950	C 0.836
C 0.611	C• 0.957	B 0.946	A 0.978	B 1.057	A 1.056	B 1.109	A 1.080	B 1.109	A 1.056	B 1.057	A 0.978	B 0.946	C• 0.958	C 0.611
	C 0.667	A 0.815	B 0.944	A 0.980	B 1.053	A 1.043	B 1.084	A 1.043	B 1.053	A 0.980	B 0.944	A 0.815	C 0.667	
		C 0.666	C• 0.954	B 0.944	A 0.981	B 1.032	A 1.015	B 1.032	A 0.981	B 0.944	C• 0.954	C 0.666		
			C 0.608	C 0.830	C+ 0.938	C+ 1.083	B 0.986	C+ 1.083	C+ 0.938	C 0.830	C 0.608			
					C 0.652	C 0.874	C 0.874	C 0.652						

C 0.662 | C 0.885 | C 0.884 | C 0.659

C 0.662 | C 0.885 | C 0.884 | C 0.659

F
x.xxx

FUEL TYPE
BOX POWER

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

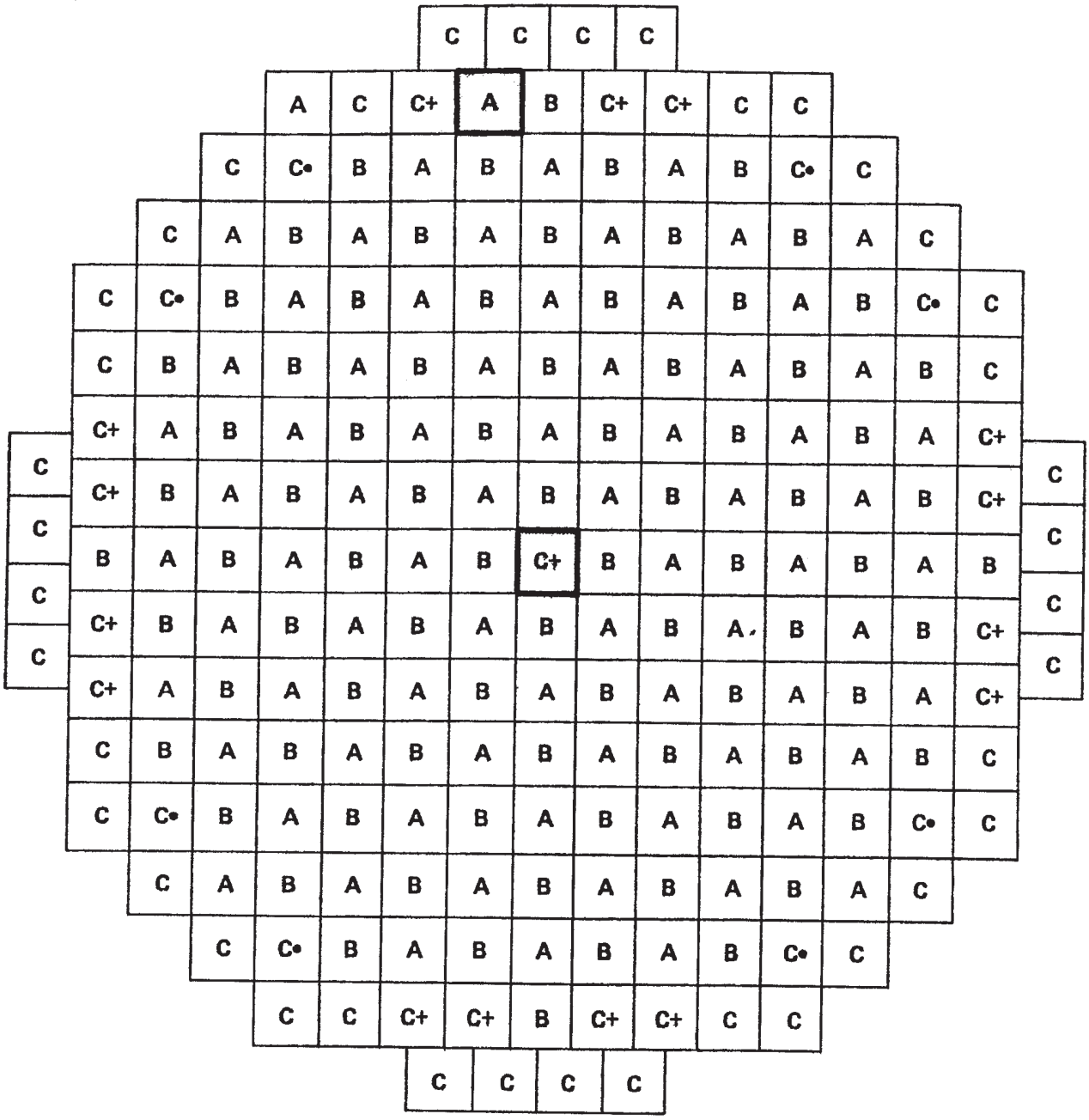
FIGURE 15.4.7-3
Unrodded Power Distribution for a Core Misloaded by Interchanging a Type A & Type B Near the Core Center

						C 0.851	B 0.803	C 1.010	C 0.795					
				C 0.867	C 1.276	C+ 1.570	C+ 1.790	B 1.410	C+ 1.404	C+ 1.145	C 0.956	C 0.673		
			C 0.845	C• 1.299	B 1.423	A 1.766	C 2.531	A 1.715	B 1.406	A 1.195	B 1.074	C• 1.034	C 0.696	
		C 0.755	A 0.975	B 1.208	A 1.373	B 1.673	A 1.799	B 1.663	A 1.376	B 1.252	A 1.087	B 0.997	A 0.830	C 0.660
	C 0.641	C• 1.036	B 1.067	A 1.163	B 1.338	A 1.419	B 1.524	A 1.422	B 1.352	A 1.198	B 1.133	A 1.003	B 0.938	C• 0.927	C 0.581
	C 0.851	B 0.985	A 1.052	B 1.175	A 1.223	B 1.332	A 1.318	B 1.339	A 1.240	B 1.206	A 1.094	B 1.055	A 0.953	B 0.900	C 0.783
	C+ 0.929	A 0.986	B 1.081	A 1.109	B 1.203	A 1.207	B 1.264	A 1.215	B 1.221	A 1.135	B 1.117	A 1.026	B 1.002	A 0.919	C+ 0.869	
C 0.626	C+ 1.042	B 1.006	A 1.031	B 1.113	A 1.119	B 1.185	A 1.161	B 1.194	A 1.136	B 1.140	A 1.064	B 1.053	A 0.974	B 0.952	C+ 0.988	C 0.594
C 0.827	B 0.930	A 0.964	B 1.040	A 1.046	B 1.114	A 1.102	B 1.149	A 1.111	B 1.133	A 1.073	B 1.075	A 1.005	B 0.996	A 0.923	B 0.891	C 0.789
C 0.616	C+ 1.006	B 0.961	A 0.976	B 1.044	A 1.040	B 1.095	A 1.072	B 1.106	A 1.061	B 1.075	A 1.014	B 1.013	A 0.944	B 0.928	C+ 0.970	C 0.784
C 0.603	C+ 0.860	A 0.898	B 0.966	A 0.971	B 1.033	A 1.022	B 1.067	A 1.035	B 1.060	A 1.008	B 1.014	A 0.949	B 0.941	A 0.873	C+ 0.834	C 0.582
	C 0.760	B 0.852	A 0.884	B 0.954	A 0.958	B 1.214	A 0.996	B 1.031	A 0.991	B 1.004	A 0.944	B 0.937	A 0.866	B 0.833	C 0.732	
	C 0.544	C• 0.852	B 0.841	A 0.869	B 0.941	A 0.941	B 0.988	A 0.962	B 0.984	A 0.934	B 0.930	A 0.857	B 0.826	C• 0.835	C 0.532	
		C 0.589	A 0.718	B 0.831	A 0.863	B 0.927	A 0.918	B 0.953	A 0.915	B 0.922	A 0.855	B 0.822	A 0.708	C 0.580	
			C 0.583	C• 0.834	B 0.825	A 0.856	B 0.900	A 0.884	B 0.898	A 0.852	B 0.819	C• 0.827	C 0.577	
				C 0.529	C 0.722	C+ 0.815	C+ 0.939	B 0.854	C+ 0.937	C+ 0.812	C 0.718	C 0.525		
						C 0.564	C 0.755	C 0.754	C 0.563					

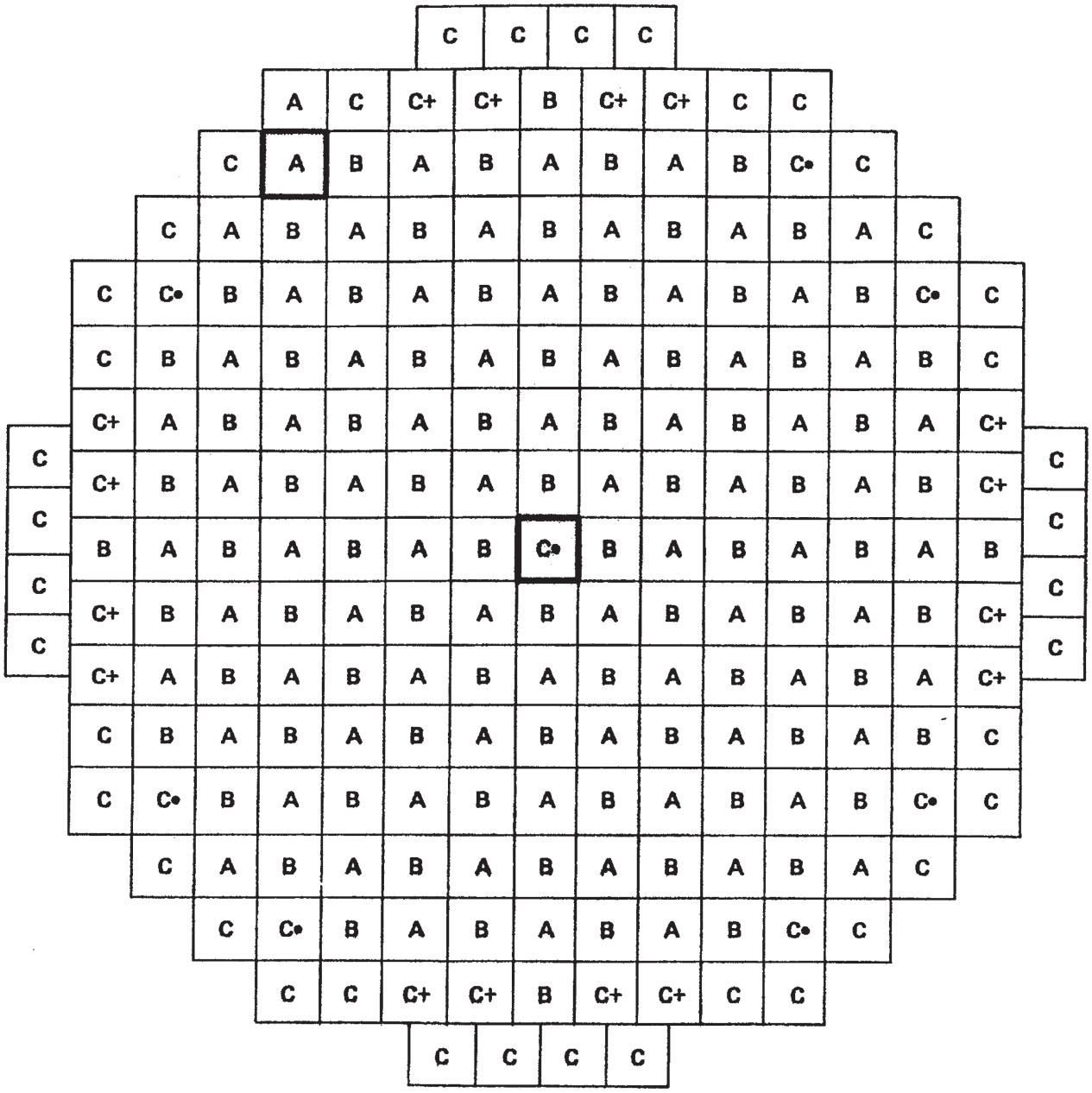
F x.xxx — FUEL TYPE BOX POWER

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FIGURE 15.4.7-4
Unrodded Power Distribution for a Core Misloaded by Interchanging a Type B & Type C Near the Core Periphery

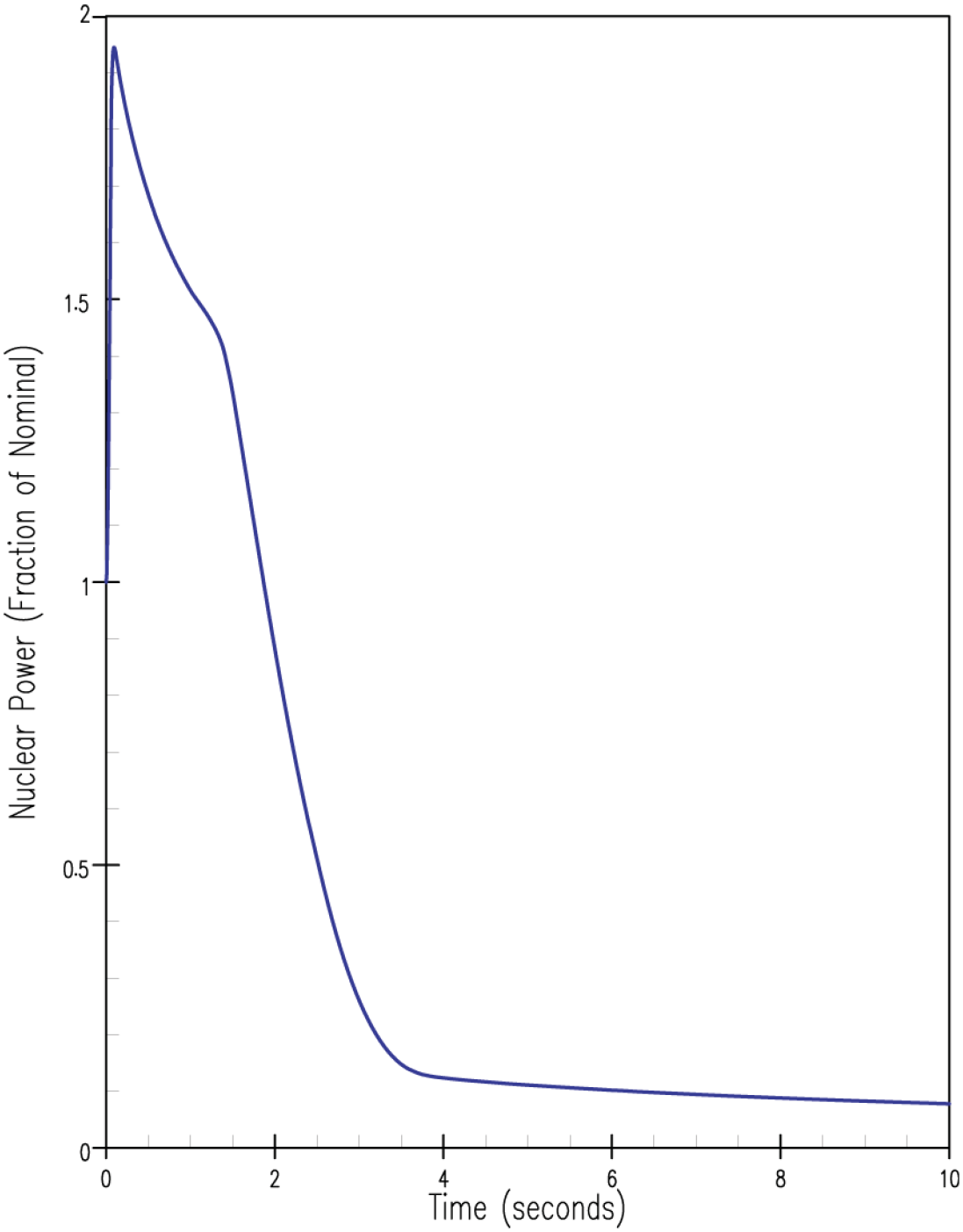


FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.7-5 Loading Pattern for Interchange of Type A and C+ Assemblies Undetectable at BOL

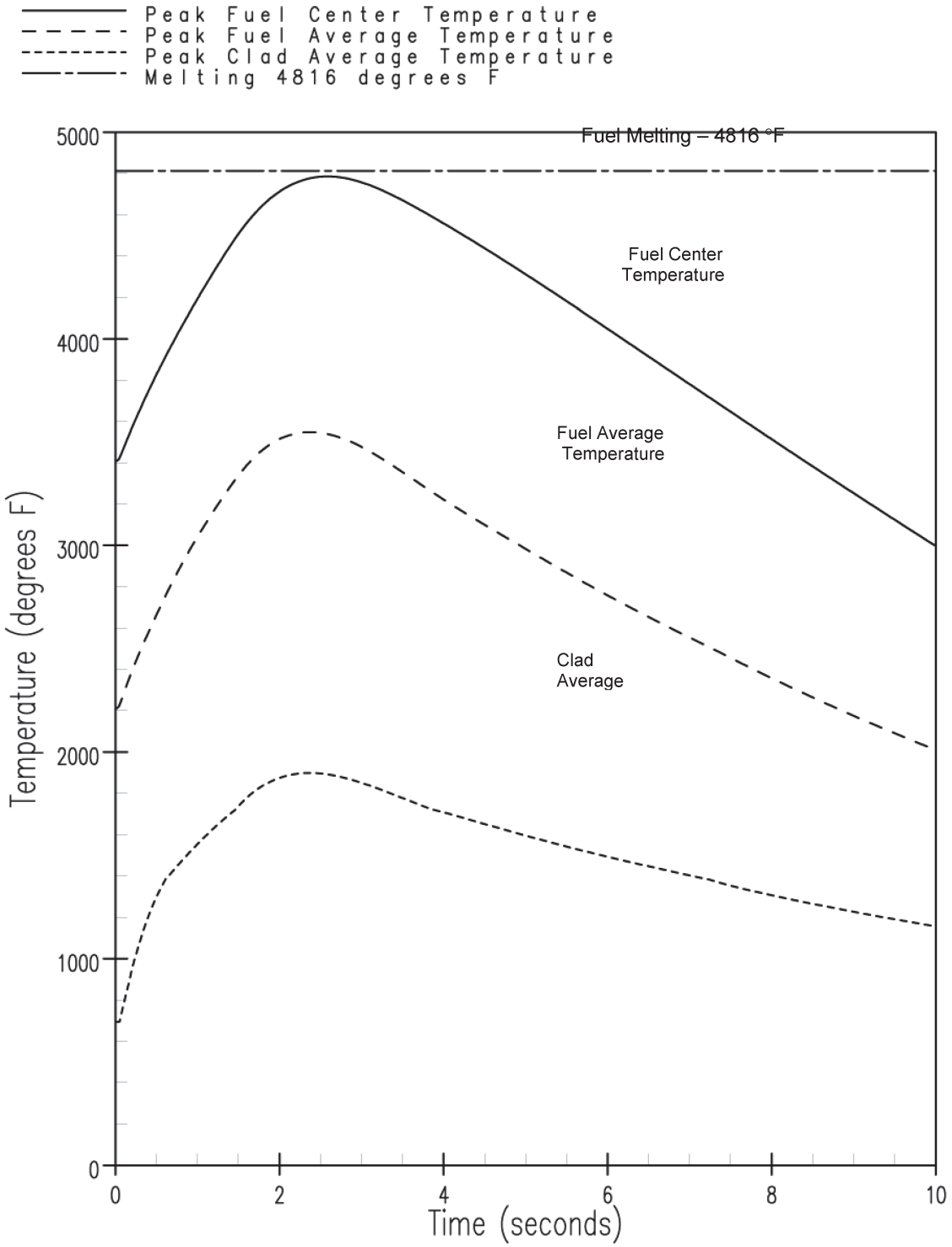


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

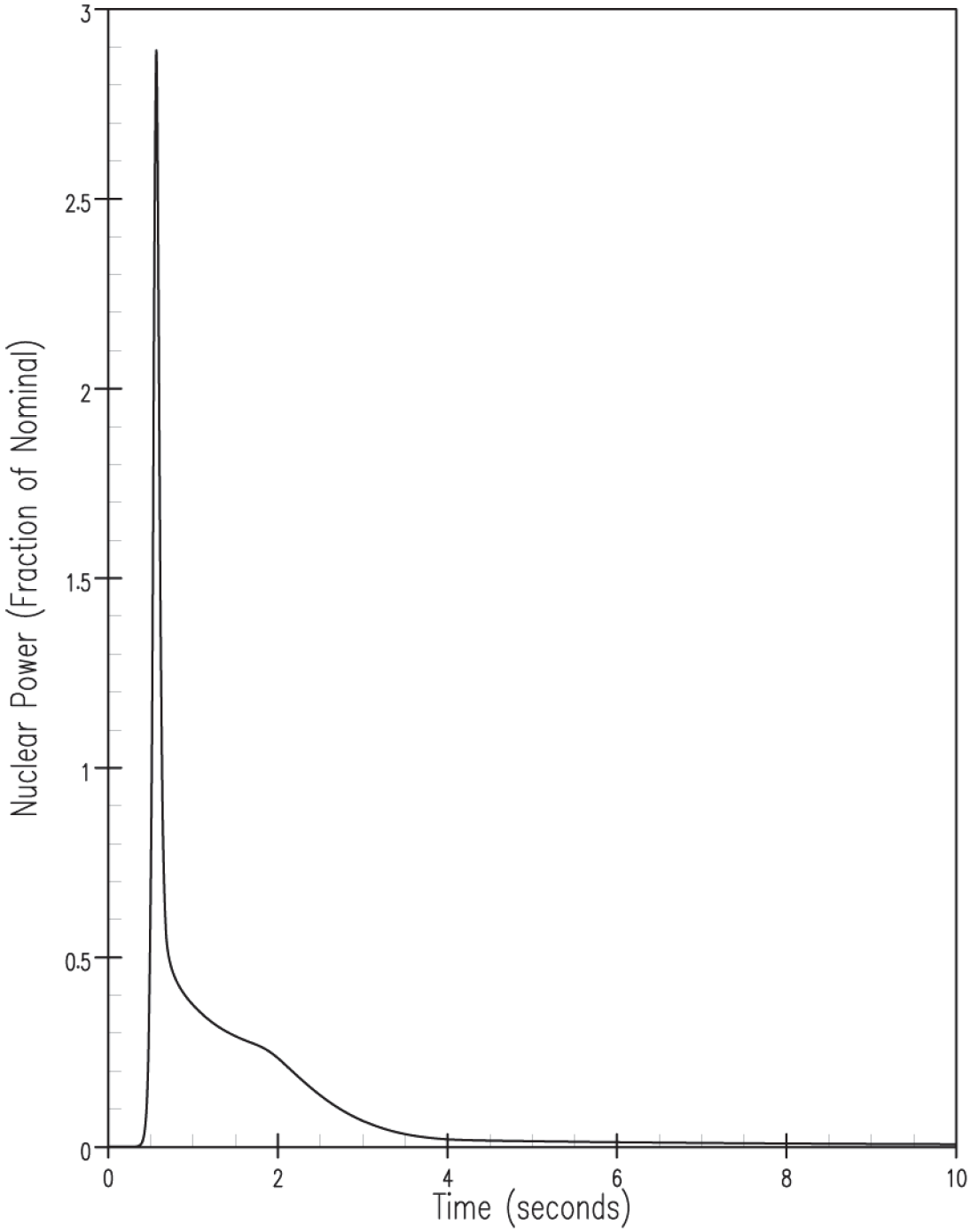
FIGURE 15.4.7-6
Loading Pattern for Interchange of Type A and C* Assemblies Undetectable at BOL



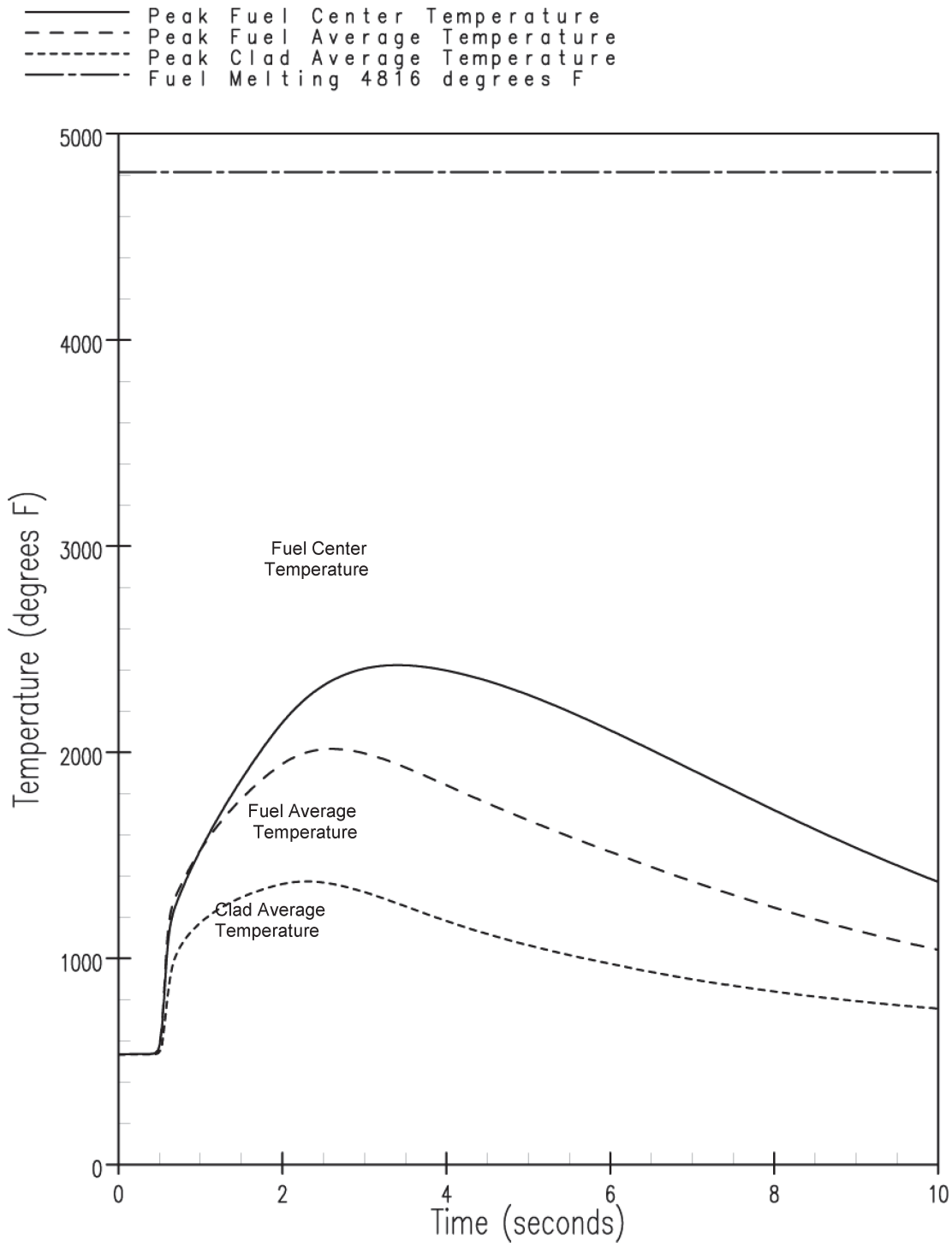
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-1 CEA Ejection Accident from Full Power, Beginning of Cycle Reactor Power vs. Time



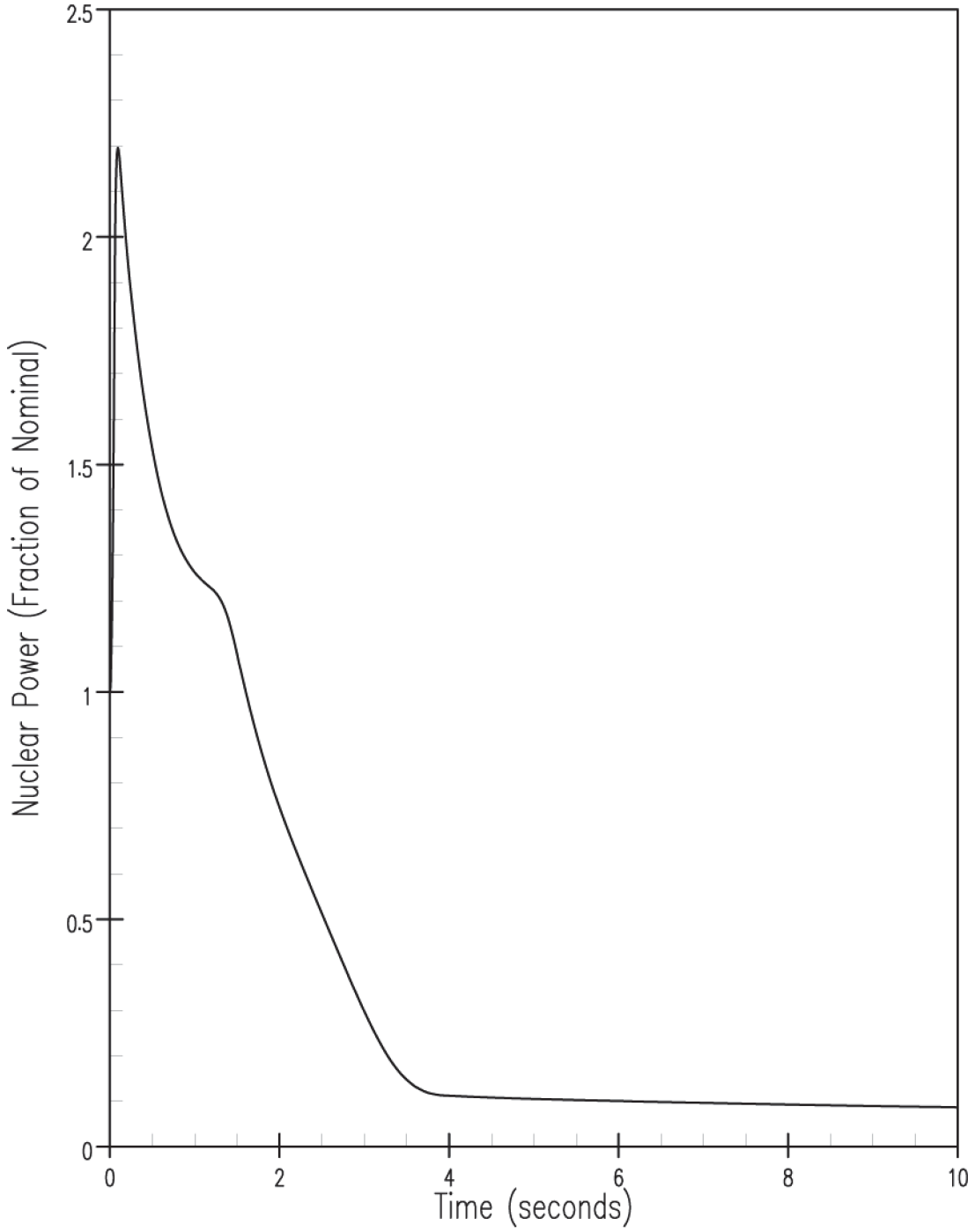
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-2 CEA Ejection Accident from Full Power, Beginning of Cycle Fuel and Cladding Temperatures vs. Time



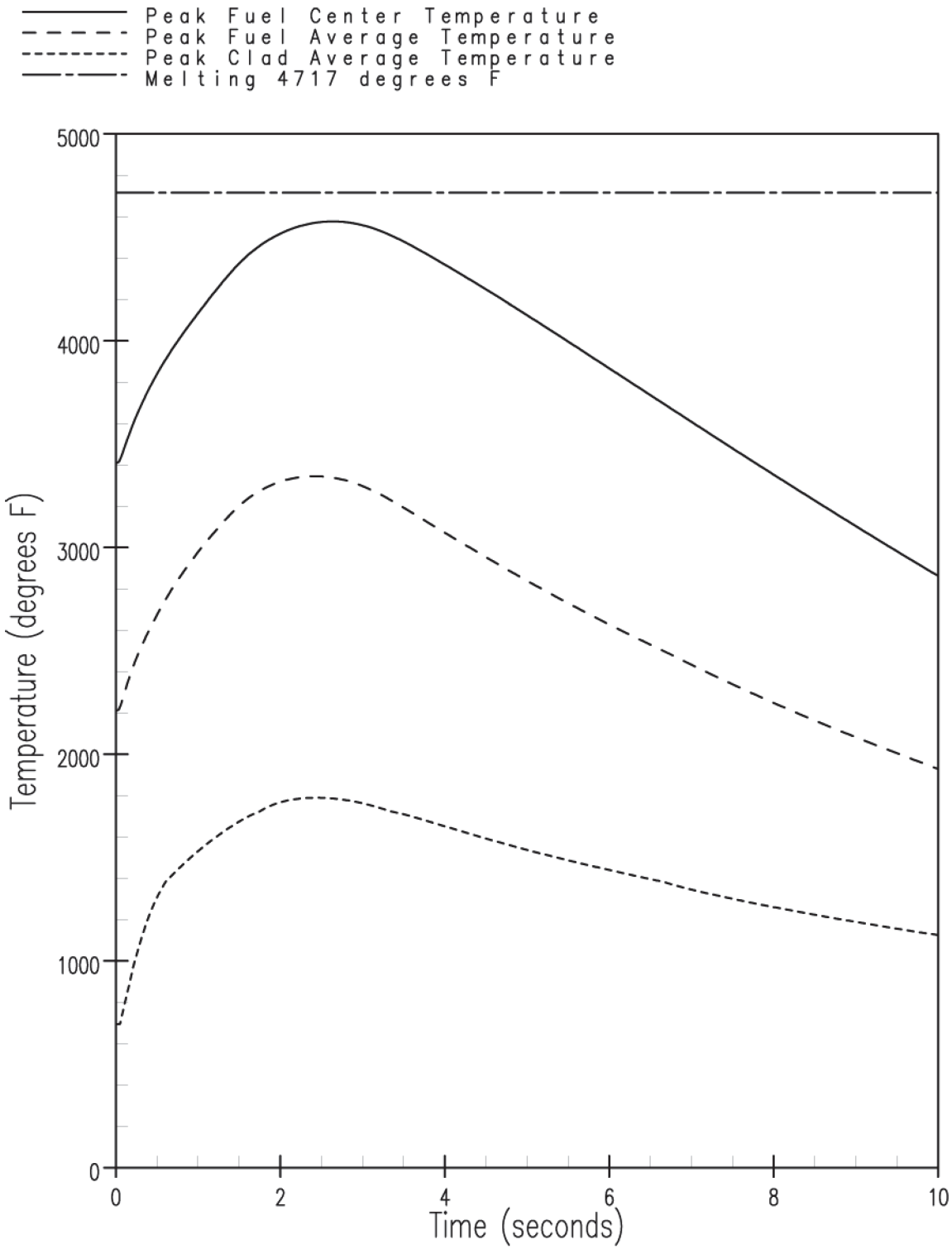
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-3 CEA Ejection Accident from Zero Power, Beginning of Cycle Reactor Power vs. Time



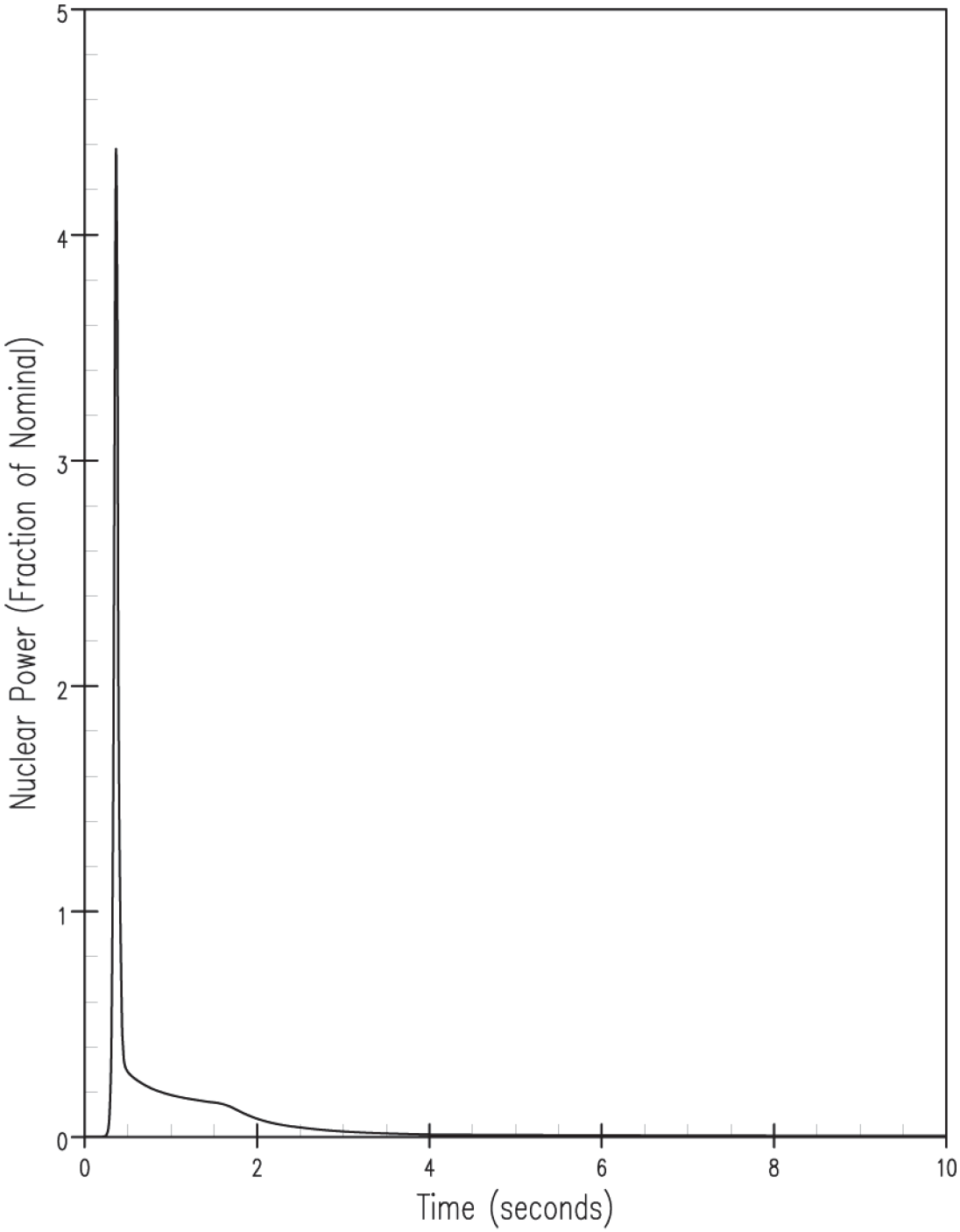
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-4 CEA Ejection Accident from Zero Power, Beginning of Cycle Fuel and Cladding Temperatures vs. Time



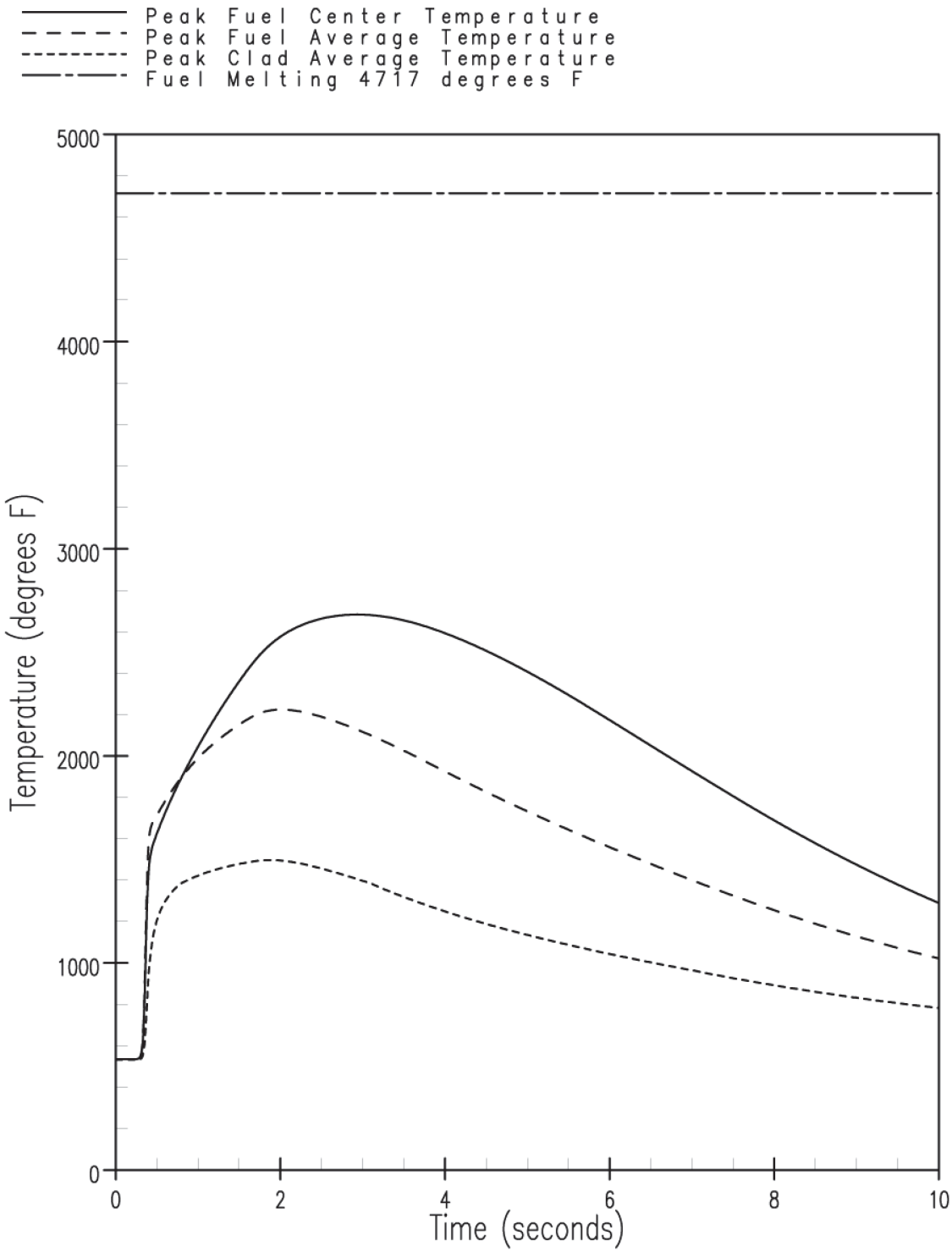
FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-5 CEA Ejection Accident from Full Power, End of Cycle Reactor Power vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-6 CEA Ejection Accident from Full Power, End of Cycle Fuel and Cladding Temperatures vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-7 CEA Ejection Accident from Zero Power, End of Cycle Nuclear Power vs. Time



FLORIDA POWER & LIGHT COMPANY ST. LUCIE PLANT UNIT 2
FIGURE 15.4.8-8 CEA Ejection Accident from Zero Power, End of Cycle Fuel and Cladding Temperatures vs. Time

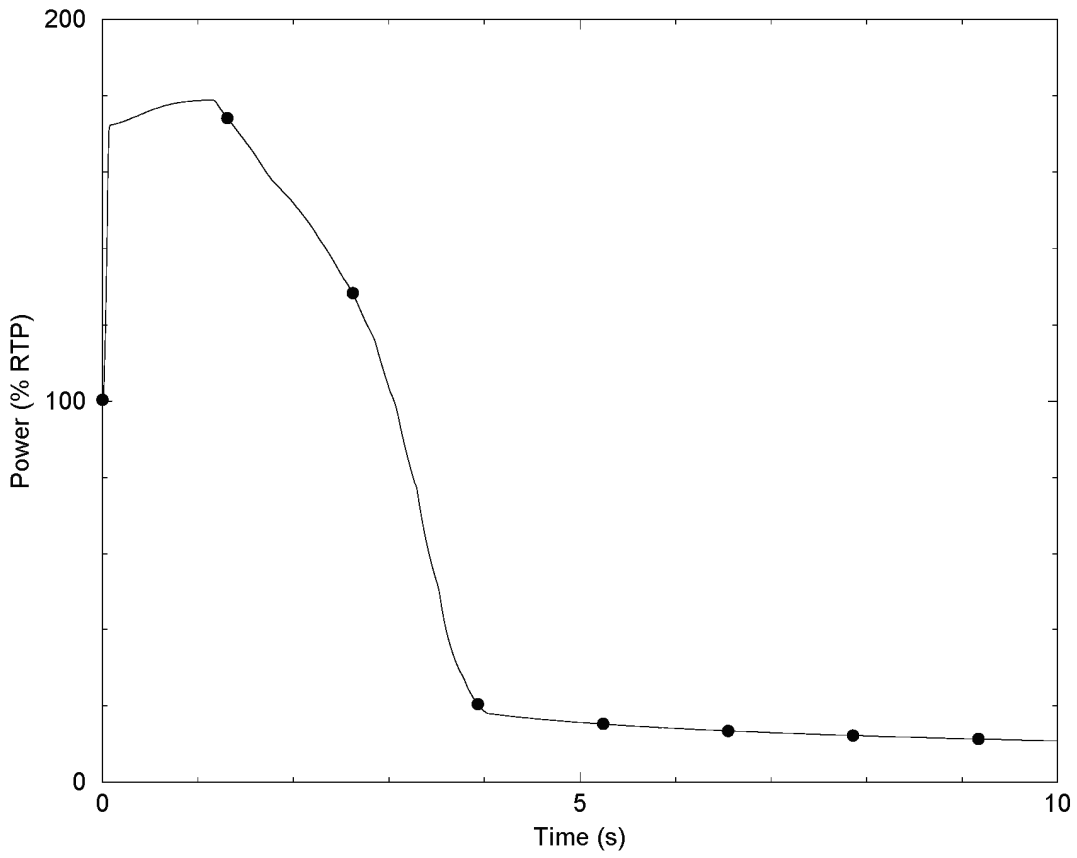


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Figure 15.4.8-9
CEA Ejection from Full Power,
BOC (AREVA Fuel Thermal):
Reactor Power vs. Time

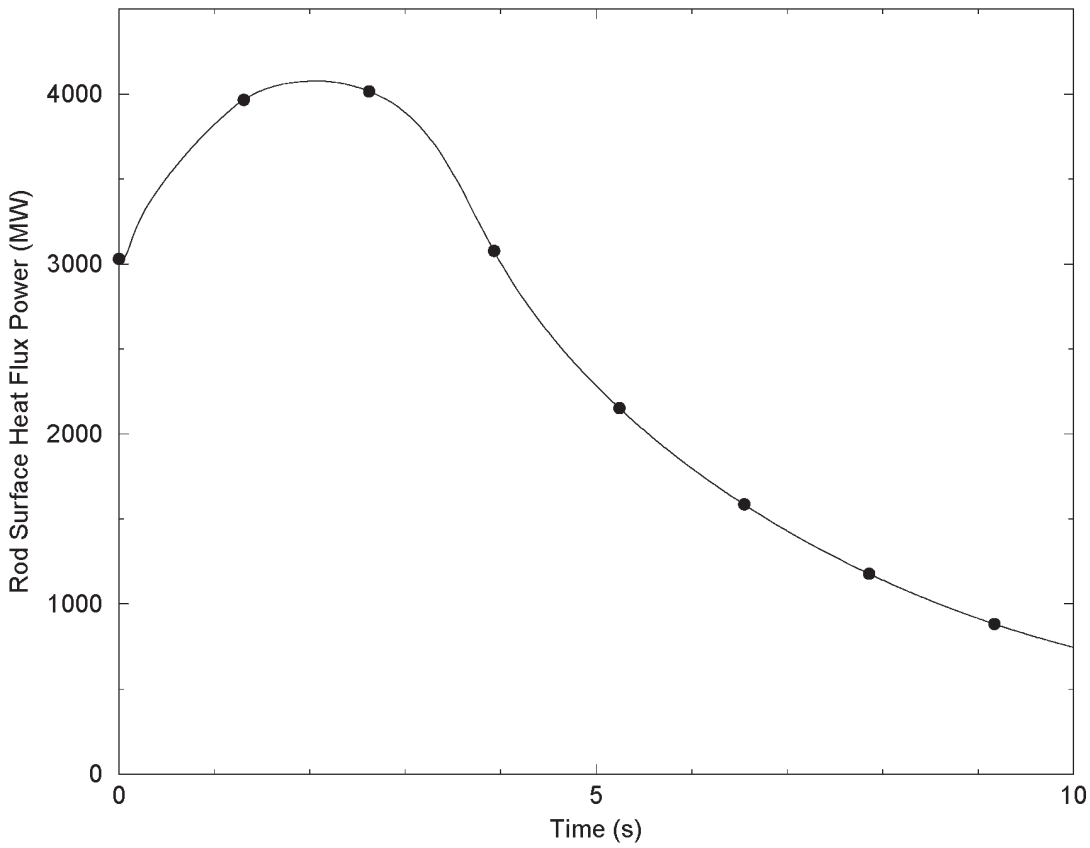

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Figure 15.4.8-10
CEA Ejection from Full Power,
BOC (AREVA Fuel Thermal):
Total Core Heat Flux Power vs. Time

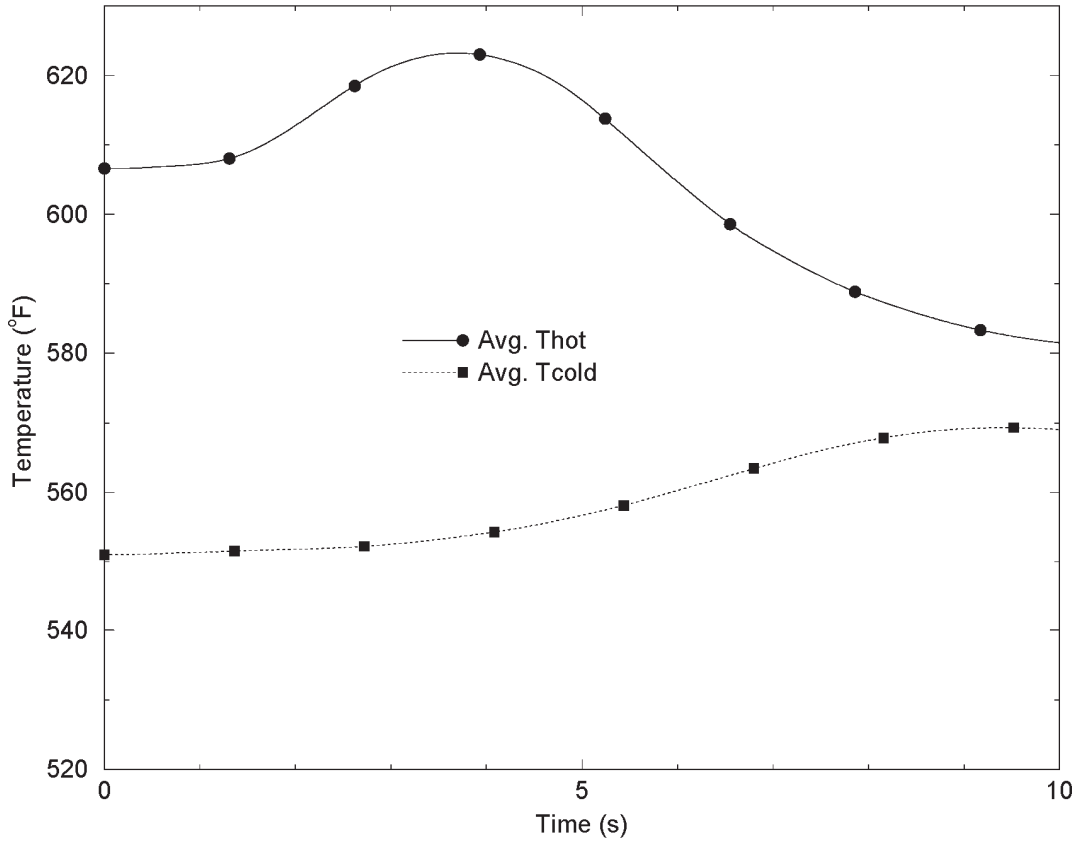

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Figure 15.4.8-11
CEA Ejection from Full Power,
BOC (AREVA Fuel Thermal):
RCS Loop Temperatures vs. Time

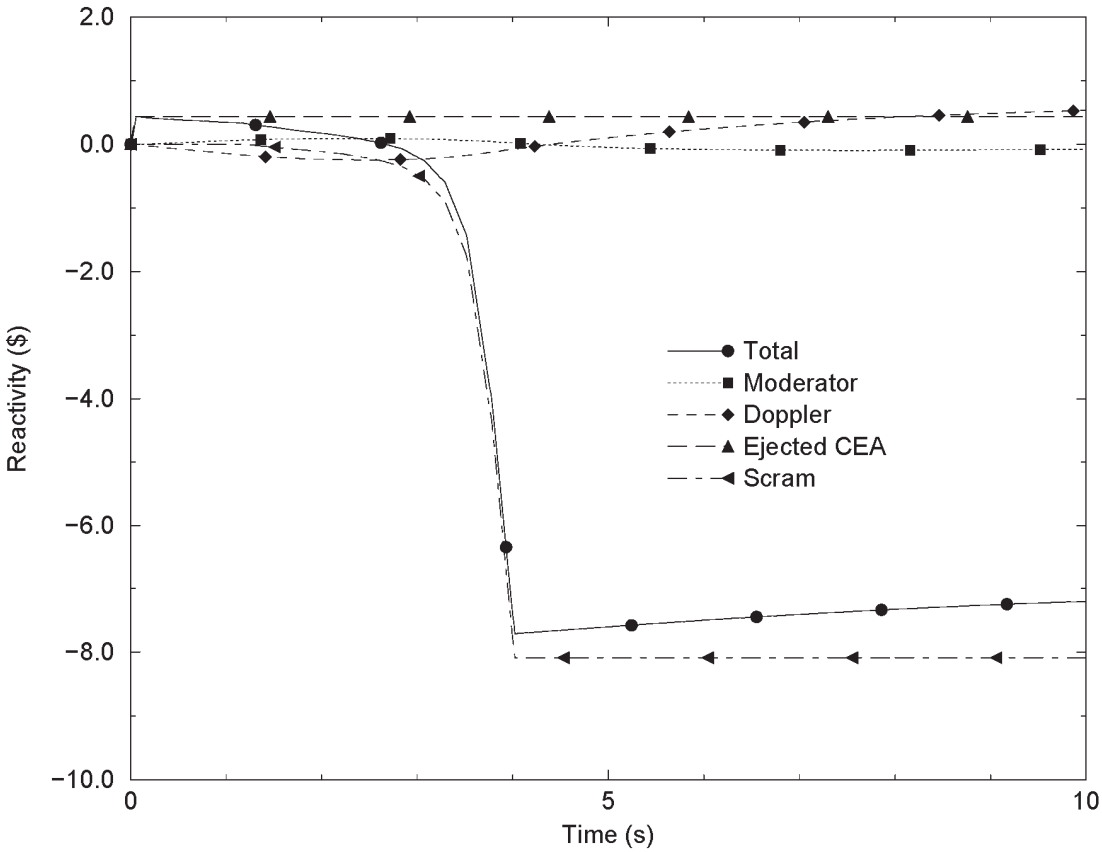

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Figure 15.4.8-12
CEA Ejection from Full Power, BOC
(AREVA Fuel Thermal):
Reactivity Feedback vs. Time

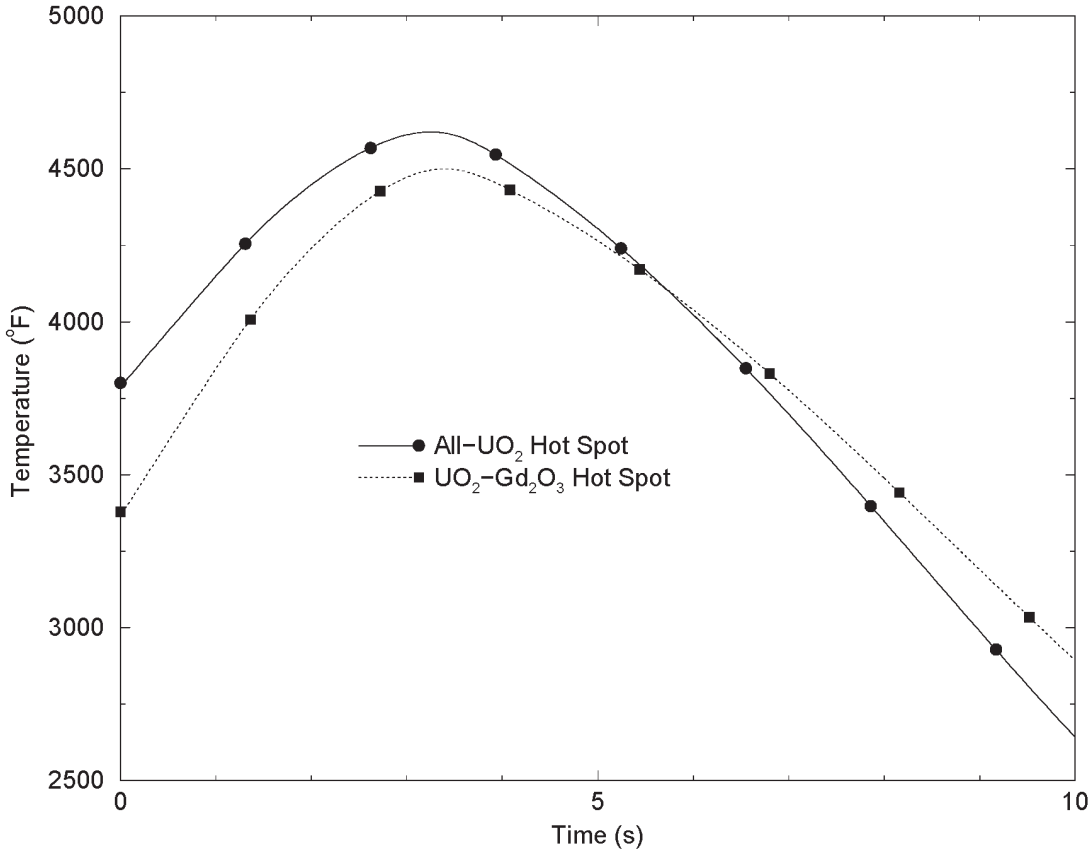

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Figure 15.4.8-13
CEA Ejection from Full Power,
BOC (AREVA Fuel Thermal):
Peak Fuel Centerline Temperatures vs. Time

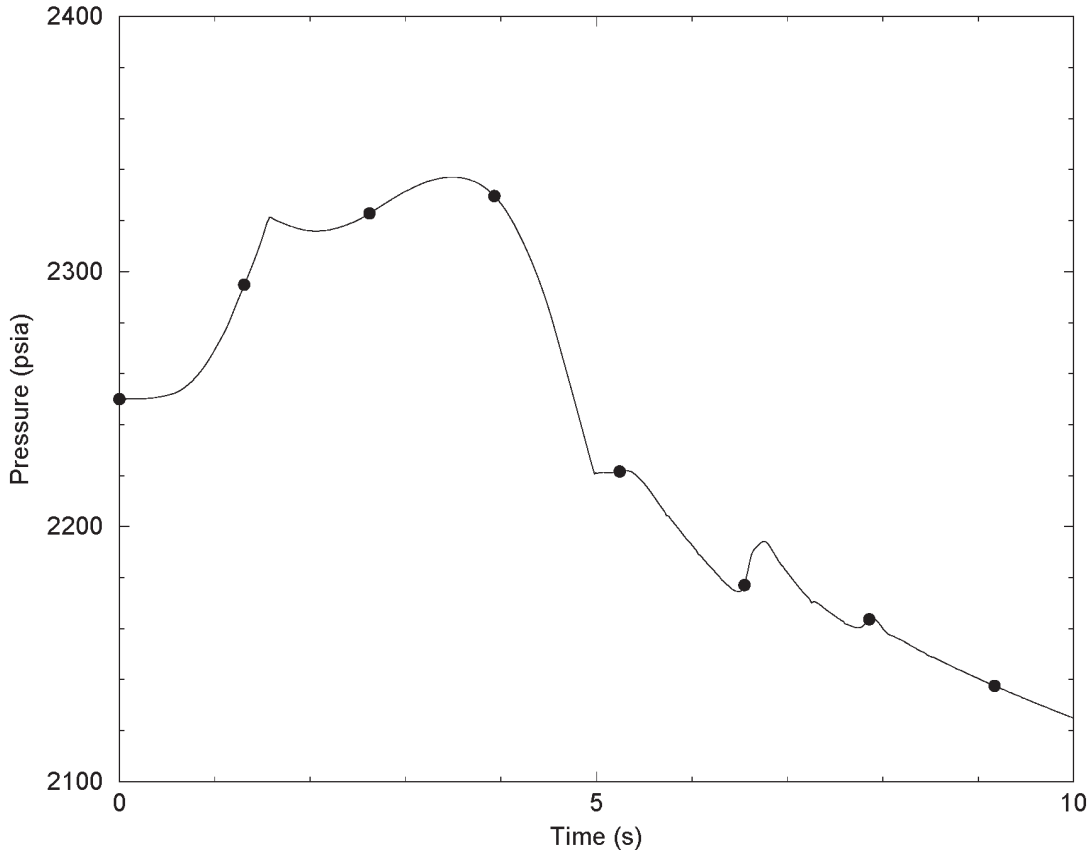

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Figure 15.4.8-14
CEA Ejection from Full Power,
BOC (AREVA Fuel Thermal):
Pressurizer Pressure vs. Time

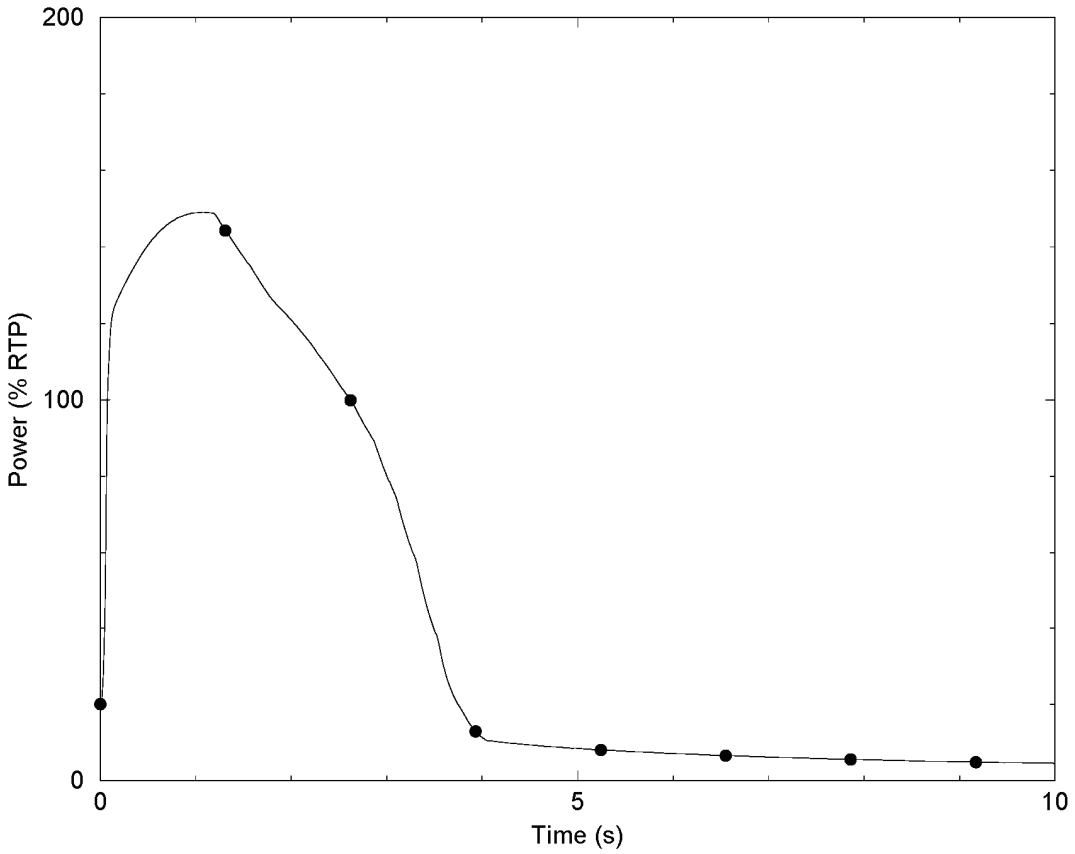

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Figure 15.4.8-15
CEA Ejection from 20% RTP,
BOC (AREVA Fuel Thermal):
Reactor Power vs. Time

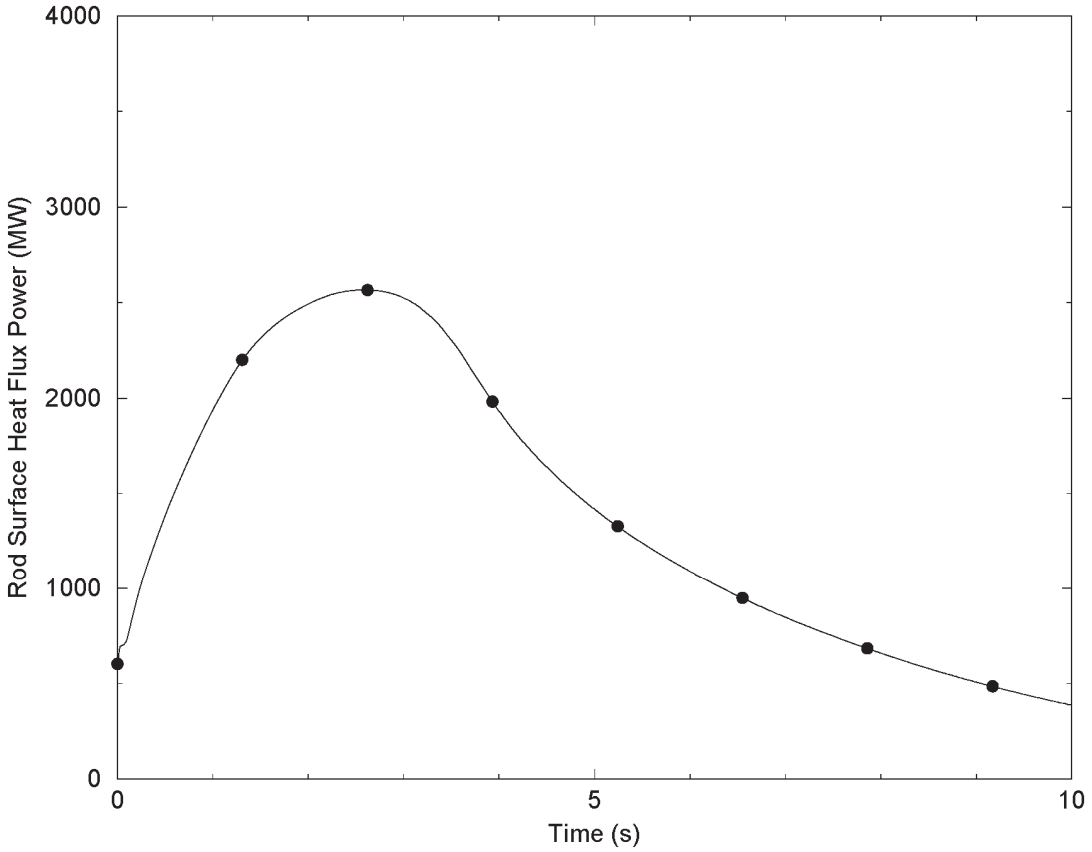

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Figure 15.4.8-16
CEA Ejection from 20% RTP,
BOC (AREVA Fuel Thermal):
Total Core Heat Flux Power vs. Time

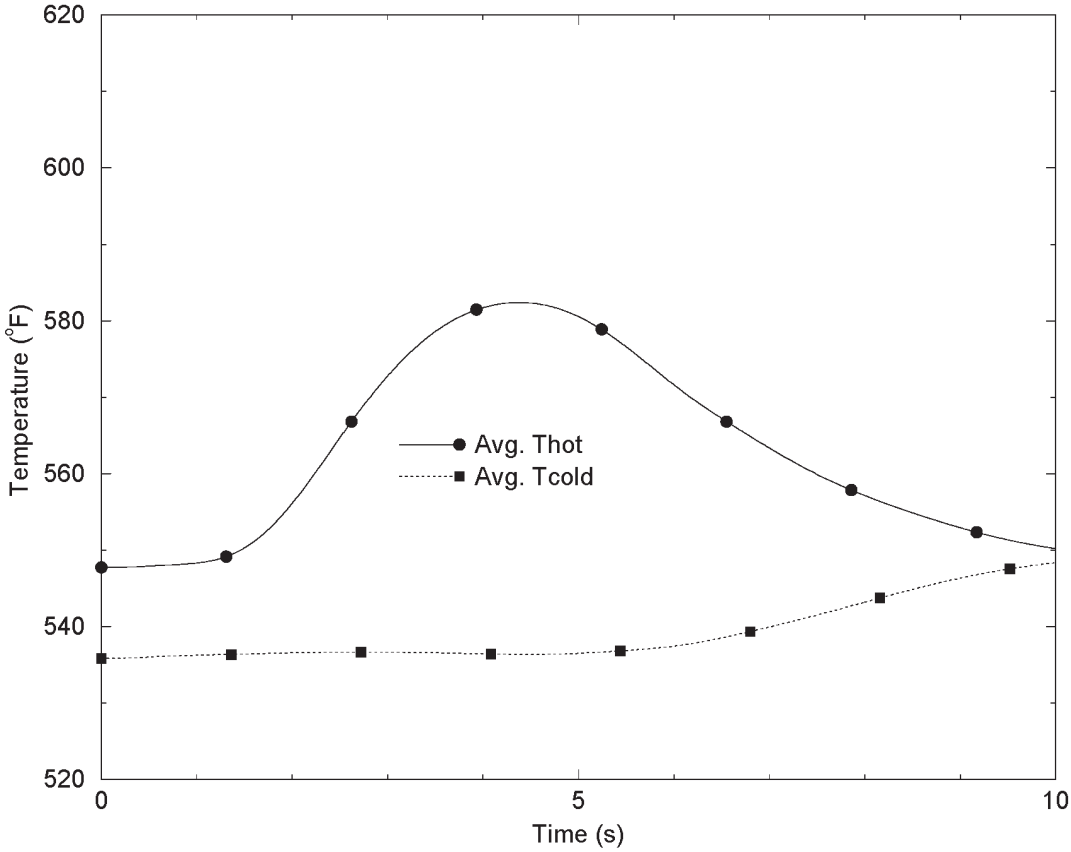

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Figure 15.4.8-17
CEA Ejection from 20% RTP,
BOC (AREVA Fuel Thermal):
RCS Loop Temperatures vs. Time

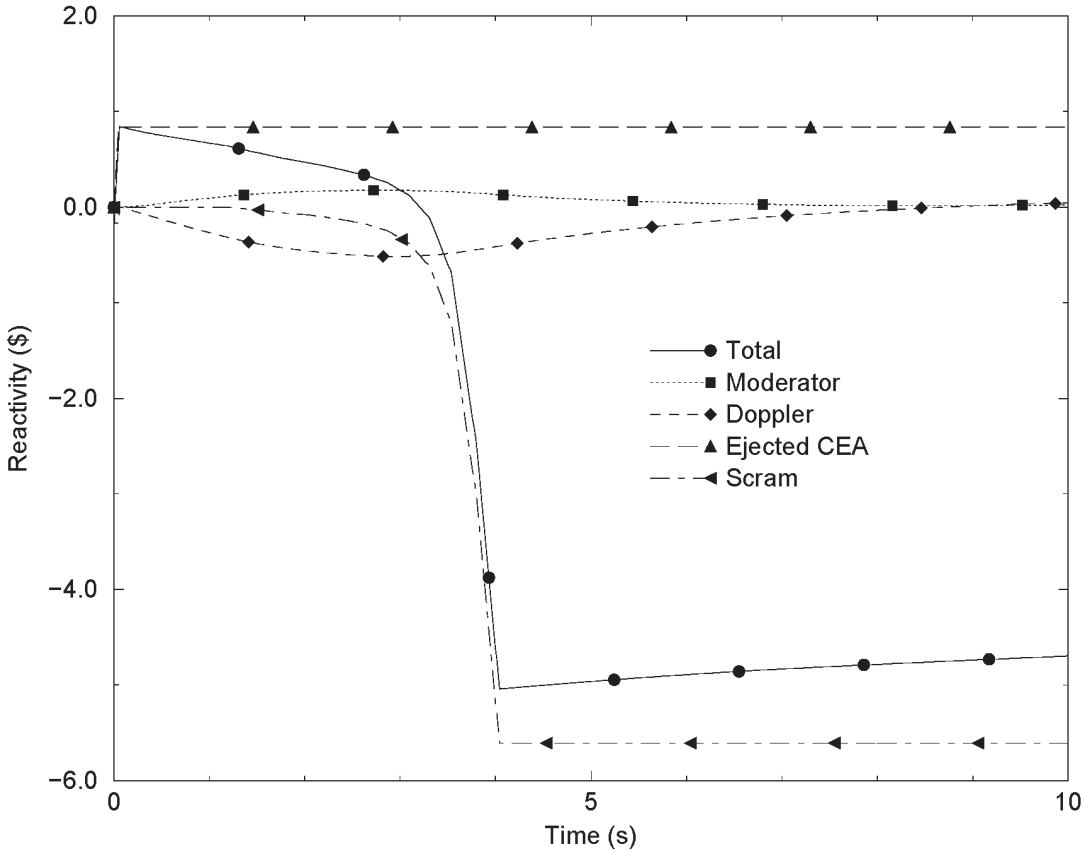

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Figure 15.4.8-18
CEA Ejection from 20% RTP,
BOC (AREVA Fuel Thermal):
Reactivity Feedback vs. Time

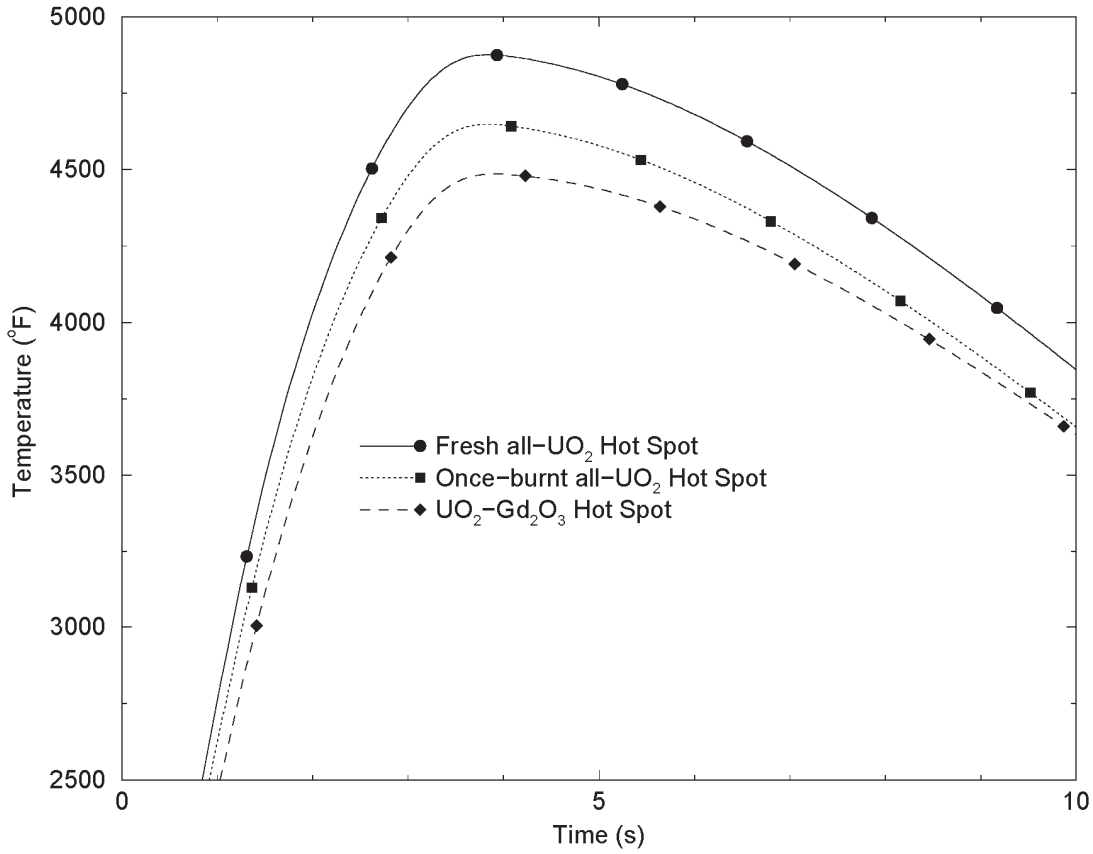

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Figure 15.4.8-19
CEA Ejection from 20% RTP,
BOC (AREVA Fuel Thermal):
Peak Fuel Centerline Temperatures vs. Time

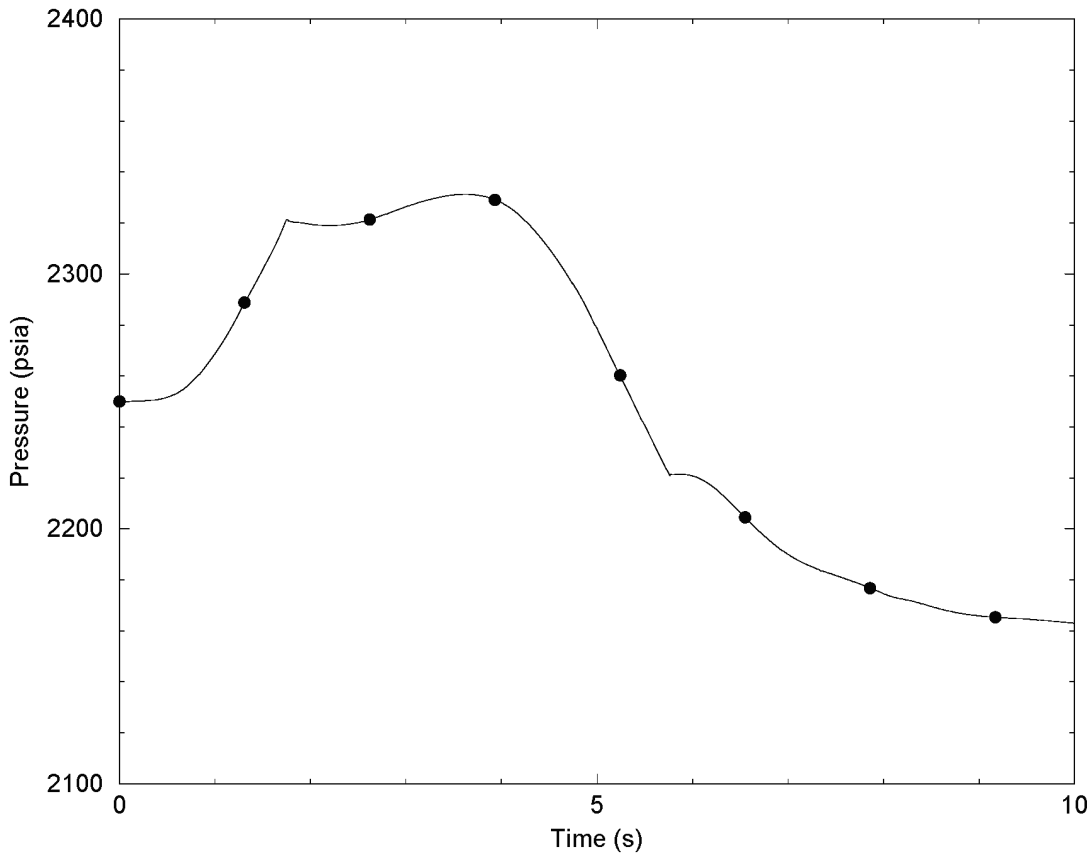

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Figure 15.4.8-20
CEA Ejection from 20% RTP,
BOC (AREVA Fuel Thermal):
Pressurizer Pressure vs. Time

15.5 INCREASE IN REACTOR COOLANT INVENTORY

Discussion and analysis of the following events are presented in this section:

a. Inadvertent operation of the emergency core cooling system during power operation (Section 15.5.1)

b. Chemical and volume control system malfunction that increases reactor coolant inventory (Section 15.5.2)

These events, considered to be ANS Condition II, cause an increase in reactor coolant inventory. Section 15.0.6 contains a discussion of ANS classification of plant conditions.

15.5.1 INADVERTENT OPERATION OF THE EMERGENCY CORE COOLING SYSTEM DURING POWER OPERATION

Inadvertent operation of the ECCS during power operation (Mode 1) is caused by a malfunction which results in startup of the safety injection pumps such as an inadvertent Safety Injection Actuation Signal (SIAS). This event is not analyzed since the shutoff head of the injection pumps is much less than the RCS pressure in Mode 1. The impact of initiation of charging flow upon SIAS is the same as the CVCS malfunction event analyzed in Section 15.5.2. Therefore, this event is bounded by UFSAR event 15.5.2 (CVCS Malfunction That Increases Reactor Coolant Inventory), including the fuel transition. EC287528

15.5.2 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT INCREASES REACTOR COOLANT INVENTORY

15.5.2.1 Accident Description

A Chemical and Volume Control System (CVCS) Malfunction event that produces an unplanned increase in reactor coolant system inventory may be caused by operator error or a failure in the pressurizer level transmitter which causes an erroneous low-low level signal. The generated signal will be transmitted to the controller which responds by actuating a second charging pump and closing the letdown flow control valve to its minimum flow position. The CVCS Malfunction is assumed to occur without increasing or diluting the primary coolant initial boron concentration. With the mismatch between letdown and charging flow, the pressurizer mixture level and pressure increase. The pressurizer sprays mitigate the pressure increase. The operators are alerted to the event either by a high pressurizer pressure trip (HPPT) or by the pressurizer high level alarm (PHLA). Twenty (20) minutes after either HPPT or the PHLA, it is assumed that the operators mitigate the event by reducing charging flow or restoring letdown flow. The case of a CVCS malfunction that produces a boron dilution is presented in Section 15.4.6.

15.5.2.2 Method of Analysis

The CVCS malfunction at power transient is analyzed by employing the detailed digital computer code RETRAN (References 15.5.3-1 and 15.5.3-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The analysis of the CVCS Malfunction event has been performed to demonstrate that operators have a sufficient amount of time to preclude pressurizer filling following a high pressurizer level alarm. To maximize the peak pressurizer mixture volume following the high pressurizer level alarm, the following assumptions are made:

1. An initial core power of 3030 MWt based on rated core power of 3020 MWt, plus 0.3% power measurement uncertainty.

2. A maximum steam generator tube plugging level of 10%.

3. Initial values of pressurizer pressure, vessel average temperature (T_{avg}) and pressurizer level are provided in Table 15.0-27.

4. Maximum charging flow is 49 gpm per pump for a total of 98 gpm for two charging pumps. This is reduced by 4 gpm for the reactor coolant pump bleed-off flow and results in a total charging flow assumption of 94 gpm.

5. The initiating event is an erroneous low-low level signal that actuates a second charging pump and closes the letdown flow control valve to the minimum position.

6. The assumed single failure is the complete closure of the letdown flow control valve that occurs concurrently with the start of the second charging pump.

7. The charging flow boron concentration is assumed to be equal to the initial RCS boron concentration.

8. The pressurizer high level alarm setpoint is assumed to be 70% of Tap Span.

9. The pressurizer safety valves are assumed to have a -3% tolerance.

10. Operator action is assumed to occur at 20 minutes after the Pressurizer High Level Alarm actuates.

11. Maximum reactivity feedback conditions are assumed.

12. Pressurizer sprays and heaters are assumed in the automatic mode.

The CVCS Malfunction is a Condition II event and is analyzed to show that the Condition II limits (specifically, generation of a more serious plant condition, pressurizer fill) are not exceeded. The applicable Condition II acceptance criteria are discussed as follows.

With respect to peak RCS and Main Steam System pressures, the CVCS Malfunction at power event is bounded by the Loss of Condenser Vacuum event described in Section 15.2.3, which is analyzed with assumptions that are made to conservatively calculate the RCS and main steam system pressure transients.

With respect to the fuel damage acceptance criterion, the CVCS Malfunction at power event is bounded by the CEA Bank Withdrawal at power event described in Section 15.4.2. During the CVCS Malfunction there are very small increases in core power and RCS temperatures, and a very small change in RCS mass flow. The RCS pressure increase is limited by the pressurizer

sprays and offsets any negative effects due to the minimal changes in other departure from nucleate boiling (DNB) related parameters.

With respect to the acceptance criterion of not generating a more serious plant condition, this is satisfied by demonstrating that the Pressurizer Safety Valves (PSVs) do not discharge water. Due to the mismatch between charging and letdown flows, the pressurizer water volume increases during the CVCS Malfunction at power event. Operator action is required to preclude water discharge through the PSVs.

With respect to the fission product barrier failure criterion, this is met by demonstrating that the DNB design basis is satisfied. Thus, there is no loss of function of any fission product barrier for the CVCS Malfunction at power event.

15.5.2.3 Results

The RETRAN code analysis assumptions are listed in Table 15.0-27 and in the section above. Table 15.5.2-1 lists the Time Sequence of Events. Figures 15.5.2-1 to 15.5.2-5 present the key transient parameters during the event. The pressurizer does not fill within the 20-minute timeframe required for operator action.

15.5.2.4 Conclusions

The results demonstrate that the pressurizer volume does not become water solid prior to 20 minutes after the pressurizer high level alarm is actuated. The CVCS Malfunction at power event is assumed to be mitigated by operator action prior to the pressurizer filling and no water is discharged through the PSVs. Thus, it is concluded that this transient does not generate a more serious plant condition. The change in fuel design parameters has no effect on the filling of the pressurizer or RCS pressure during this event. Thus, this event does not require a re-analysis for the fuel transition. EC287528

15.5.3 REFERENCES

15.5.3-1 WCAP-14882-P-A, Rev. 0, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April, 1999.

15.5.3-2 EPRI NP-1850-CCM, Rev. 6, “RETRAN-02 – A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems,” December 1995.

Table 15.5.2-1
Sequence of Events for the CVCS Malfunction Event

Event	Time (seconds)
Erroneous low-low level pressurizer pevel control System signal, second charging pump starts, Letdown Flow is isolated	10.0
Pressurizer High Level Alarm Occurs	374.4
Maximum Pressurizer Pressure	956.0
Operator Action occurs to mitigate the event	1574.4

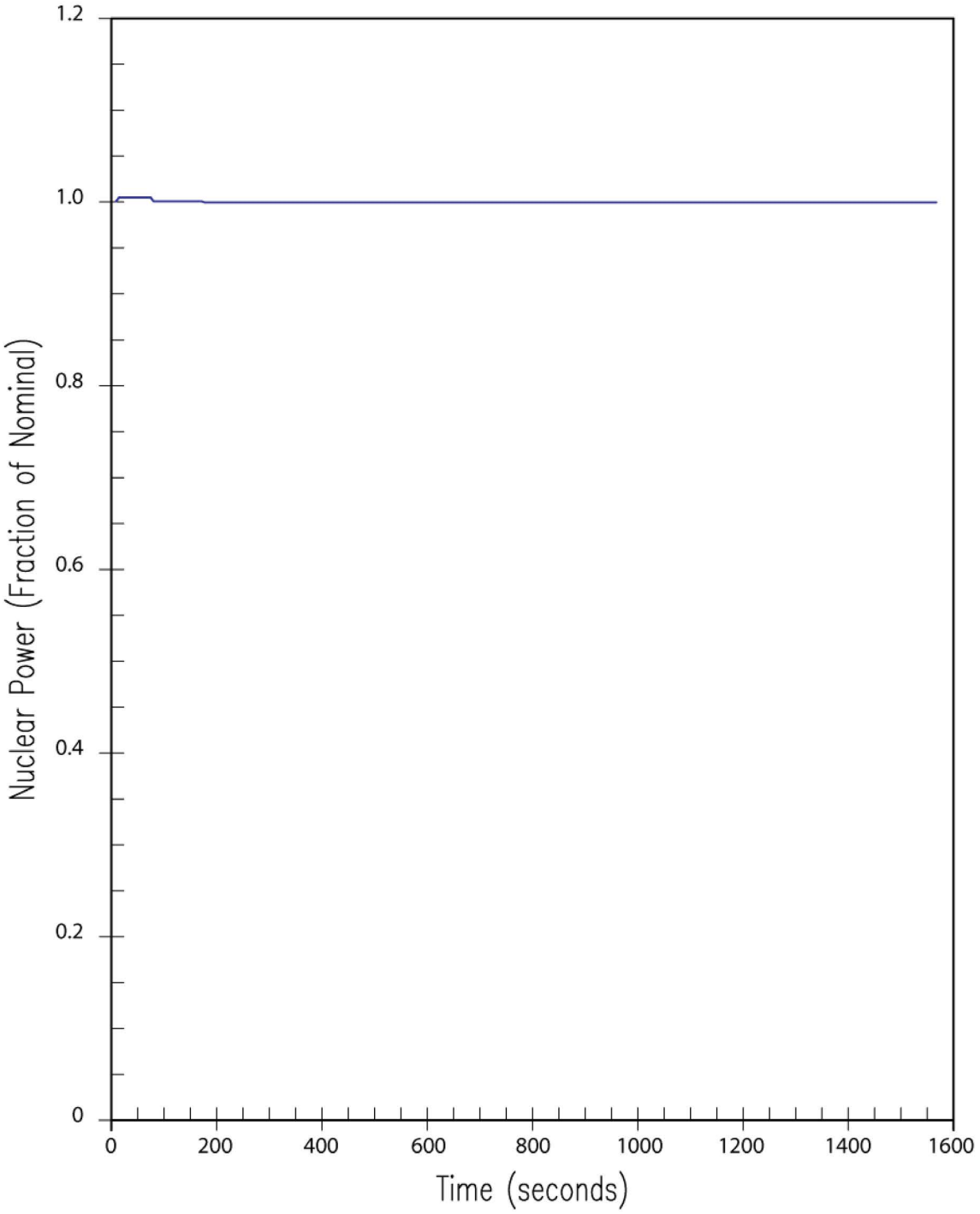

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FIGURE 15.5.2-1 CVCS Malfunction Nuclear Power vs. Time

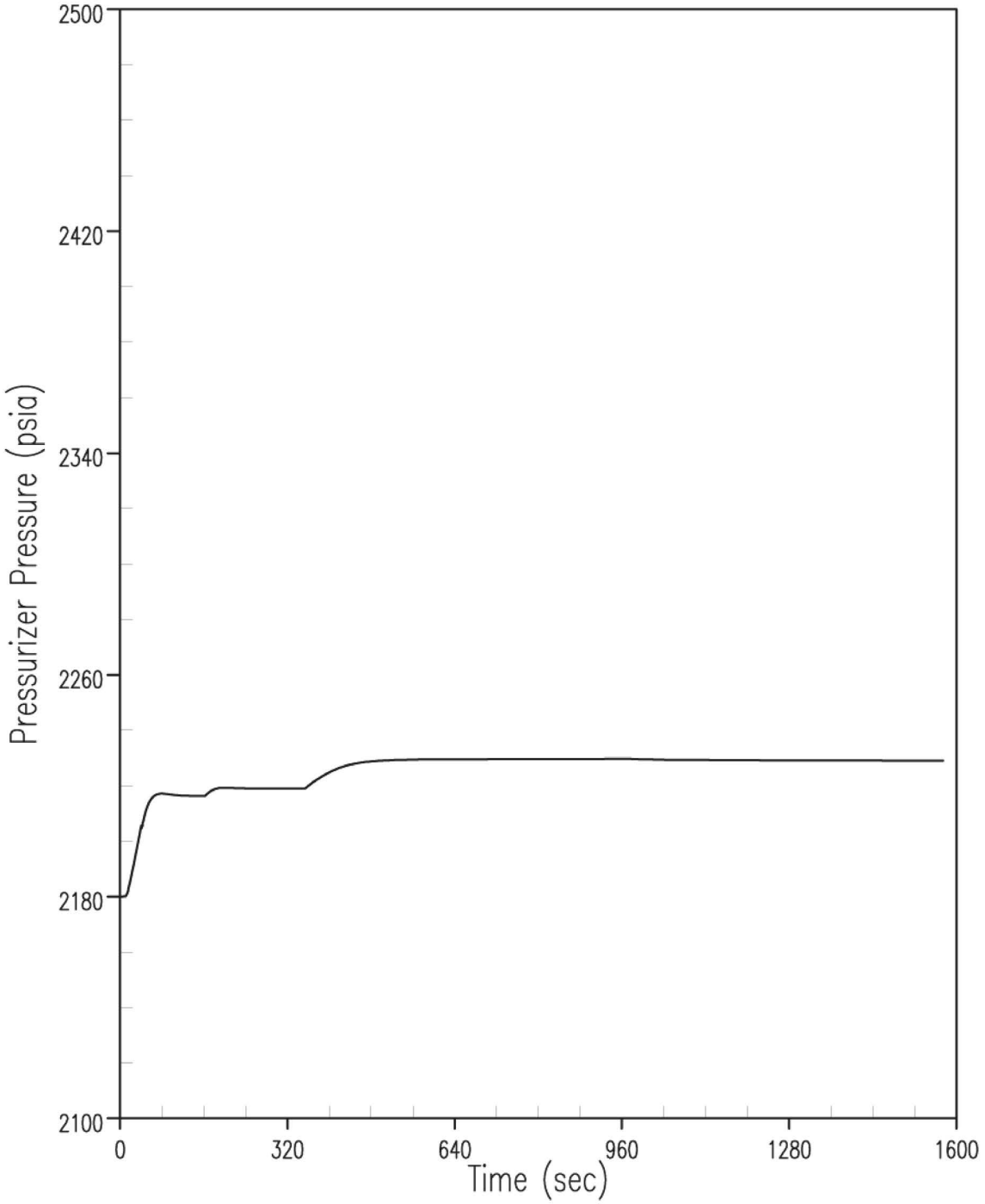

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FIGURE 15.5.2-2 CVCS Malfunction Pressurizer Pressure vs. Time

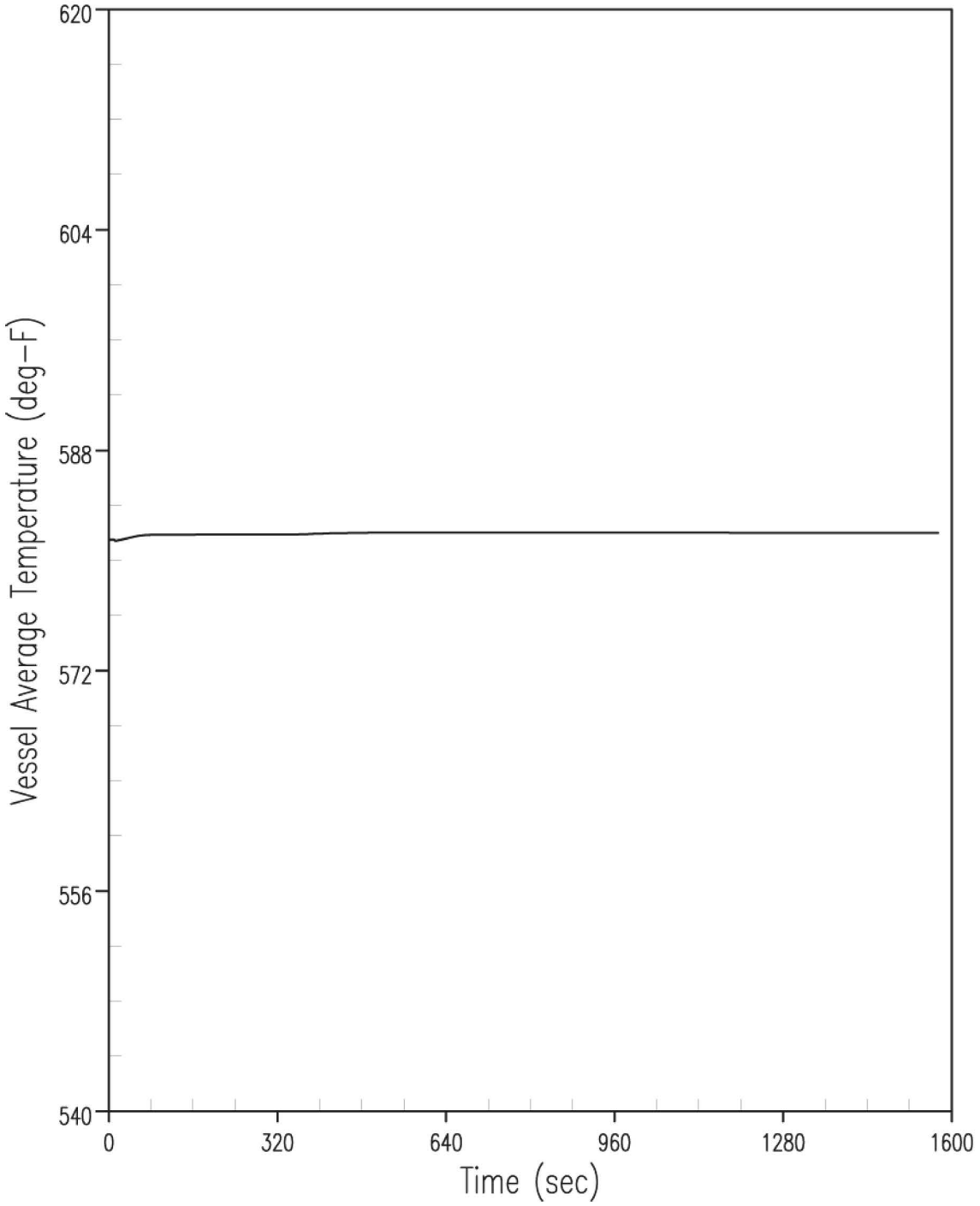

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FIGURE 15.5.2-3 CVCS Malfunction Vessel Average Temperature vs. Time

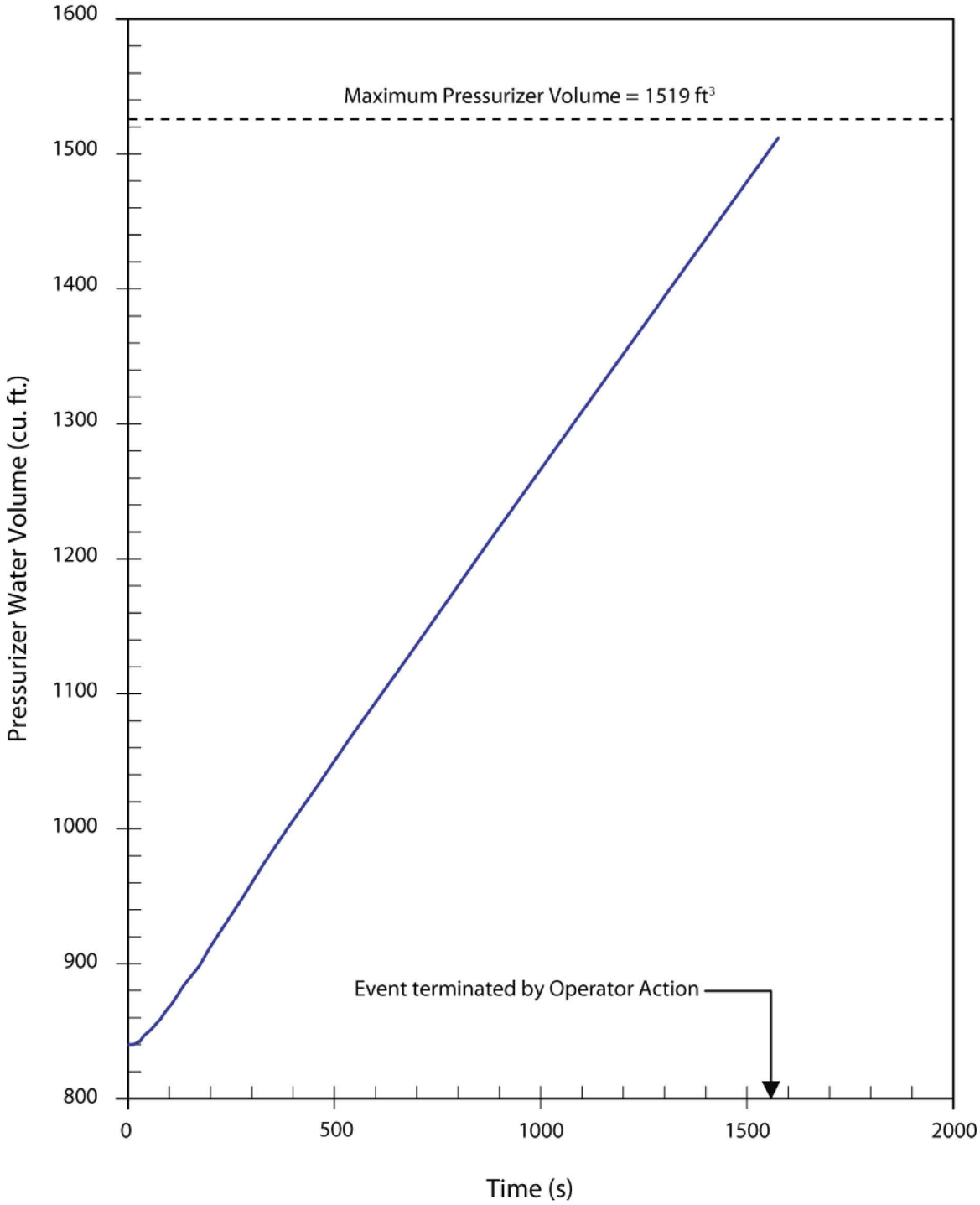

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FIGURE 15.5.2-4 CVCS Malfunction Pressurizer Water volume vs. Time

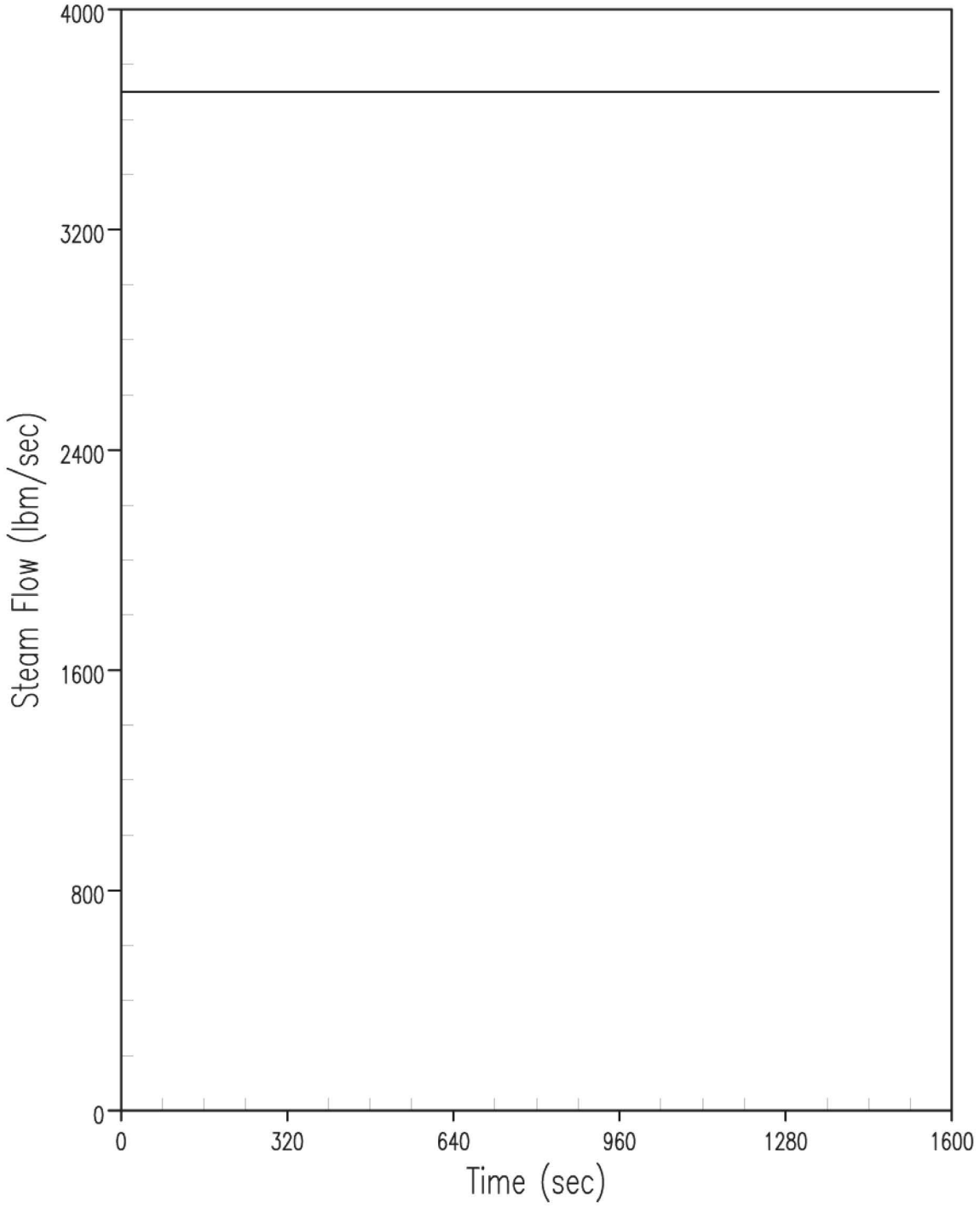

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FIGURE 15.5.2-5 CVCS Malfunction Steam Flow vs. Time