Florida Power & Light, 9760 S.W. 344 St. Homestead, FL 33035

FPL.

AUG 19 2011

L-2011-305
10 CFR 50.90

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

Re: Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205 and Reactor Systems Issues

References:

(1) M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2010-113), "License Amendment Request No. 205: Extended Power Uprate (EPU)," (TAC Nos. ME4907 and ME4908), Accession No. ML103560169, October 21, 2010.

(2) Email from J. Paige (NRC) to S. Hale (FPL), "Turkey Point EPU - Reactor Systems (SRXB) Request for Additional Information - Round 1.4 (Part 4)," Accession No. ML11202A174, July 21, 2011.

(3) M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2011-233), "Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205 and Reactor Systems Issues," August 5, 2011.

(4) Email from J. Paige (NRC) to S. Hale (FPL), "Turkey Point EPU - Reactor Systems (SRXB) Request for Additional Information - Round 1.4 (Part 4)," Accession No. ML11213A247, July 29, 2011.

By letter L-2010-113 dated October 21, 2010 [Reference 1], Florida Power and Light Company (FPL) requested to amend Renewed Facility Operating Licenses DPR-31 and DPR-41 and revise the Turkey Point Units 3 and 4 Technical Specifications (TS). The proposed amendment will increase each unit's licensed core power level from 2300 megawatts thermal (MWt) to 2644 MWt and revise the Renewed Facility Operating Licenses and TS to support operation at this increased core thermal power level. This represents an approximate increase of 15% and is therefore considered an extended power uprate (EPU).

By email from the NRC Project Manager (PM) dated July 21, 2011 [Reference 2], additional information regarding reactor safety analysis issues was requested by the NRC staff in the Reactor Systems Branch (SRXB) to support the review of the EPU LAR [Reference 1]. The RAI consisted of thirty-nine (39) questions regarding loss-of-coolant accident (LOCA) and non-LOCA analyses. On August 5, 2011, FPL provided its response to RAI questions SRXB-1.3.1-1.3.6 and 1.3.16-1.3.38 via FPL letter L-2011-233 [Reference 3] in which it was stated that the response to RAI questions SRXB-1.3.7-1.3.15 on steam line breaks would follow under separate correspondence.

By email from the NRC PM dated July 29, 2011, FPL received three (3) additional RAI question on Anticipated Transients without Scram (ATWS) Events [Reference 4]. FPL's responses to the earlier RAI questions on steam line breaks inside and outside containment and on ATWS are provided in the Attachment to this letter.

A002
A001
NRR

In accordance with 10 CFR 50.91(b)(1), a copy of this letter is being forwarded to the State Designee of Florida.

This submittal does not alter the significant hazards consideration or environmental assessment previously submitted by FPL letter L-2010-113 [Reference 1].

This submittal contains no new commitments and no revisions to existing commitments.

Should you have any questions regarding this submittal, please contact Mr. Robert J. Tomonto, Licensing Manager, at (305) 246-7327.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 19, 2011.

Very truly yours,

Michael Kiley
Site Vice President
Turkey Point Nuclear Plant

Attachment

cc: USNRC Regional Administrator, Region II
USNRC Project Manager, Turkey Point Nuclear Plant
USNRC Resident Inspector, Turkey Point Nuclear Plant
Mr. W. A. Passetti, Florida Department of Health

Turkey Point Units 3 and 4

RESPONSE TO NRC RAI REGARDING EPU LAR NO. 205
AND SRXB REACTOR SYSTEMS ISSUES

ATTACHMENT

Response to Request for Additional Information

The following information is provided by Florida Power and Light Company (FPL) in response to the U. S. Nuclear Regulatory Commission's (NRC) Request for Additional Information (RAI). This information was requested to support License Amendment Request (LAR) 205, Extended Power Uprate (EPU), for Turkey Point Nuclear Plant (PTN) Units 3 and 4 that was submitted to the NRC by FPL via letter (L-2010-113) dated October 21, 2010 [Reference 1].

By email from the NRC Project Manager (PM) dated July 21, 2011 [Reference 2], additional information regarding reactor safety analysis issues was requested by the NRC staff in the Reactor Systems Branch (SRXB) to support the review of the EPU LAR [Reference 1]. The RAI consisted of thirty-nine (39) questions regarding loss-of-coolant accident (LOCA) and non-LOCA analyses. On August 5, 2011, FPL provided its response to RAI questions SRXB-1.3.1-1.3.6 and 1.3.16-1.3.38 via FPL letter L-2011-233 [Reference 3] in which it was stated that the response to RAI questions SRXB-1.3.7-1.3.15 on steam line breaks would follow under a separate correspondence.

By email from the NRC PM dated July 29, 2011, FPL received three (3) additional RAI questions on Anticipated Transients without Scram (ATWS) Events [Reference 4]. FPL's responses to the earlier RAI questions on steam line breaks inside and outside containment and on the ATWS events are provided below.

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

SRXB-1.3.7 UFSAR §1.3.7 states, "For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the Safety Injection System adds shutdown reactivity so that with a stuck rod, no off-site power and minimum engineered safety features, there is no consequential damage to the fuel or the primary system and the core remains in place and intact."

a. **LR §2.8.5.1.2.2.1.2 states that, "Cases were analyzed both with offsite power available (full coolant flow is maintained) and with a coincident loss of offsite power (causing the reactor coolant pumps to coast down 3.0 seconds following the break)." Provide the results of the analysis of the major rupture of a steam pipe at HZP, without offsite power, to show that the above design criterion is satisfied. Include a sequence of events table indicating the times and values of peak heat flux and minimum DNBR, and transient plots that are comparable to the reported results of the equivalent steamline break case with offsite power. Include a transient plot of core flow.**

The sequence of events for the analysis of a major rupture of a steam pipe from HZP conditions, without offsite power, is provided in Table SRXB-1.3.7.a; the transient plots for this case are provided in Figures SRXB-1.3.7.a-1 through SRXB-1.3.7.a-8. The value for the peak core heat flux in this case is 0.0334 (fraction of nominal); given the non-limiting nature of the overall plant response for this case in comparison to the case in which offsite power is available (reactor coolant pumps continue to operate), no detailed calculation of the minimum DNBR was performed for the case without offsite power. The analysis demonstrates that the results of the case with a coincident loss of offsite power are bounded by the more limiting results associated with the case where offsite power available; therefore, all applicable safety criteria are satisfied for this event.

Table SRXB-1.3.7.a: Sequence of Events	
Event	**Time reported (sec) Without Offsite Power**
Main steam line ruptures in loop 1	0.0
High steam line flow setpoint reached in loop 1	0.01
High steam line flow setpoint reached in loop 2	0.36
High steam line flow setpoint reached in loop 3	0.37
Low SG pressure SI setpoint reached in loop 1 [(1)]	0.37
Low SG pressure SI setpoint reached in loops 2 and 3 [(1)]	1.05
High steam line flow/Low SG pressure SI setpoint is reached	1.06
RCPs begin to coastdown	3.0
SI actuation occurs	3.06
Main feedwater isolation completed in both intact loops	12.06
Steam line isolation completed in all three loops	18.96
Main feedwater isolation completed in the faulted loop	33.06
SI pumps achieve full speed	46.06
SI flow injection begins (cold leg pressure falls below SI pump shutoff pressure)	46.25
Criticality attained	52.5
Borated water from the SIS reaches the core	73.5
Accumulators begin to inject	206.0
Peak core heat flux occurs	341.25
Peak core heat flux (fraction of nominal)	0.0334

1. This function operates on a lead/lagged steam pressure signal consisting of a 50-second lead and a 5-second lag. The lead/lagged steam pressure signal responds quickly such that the Low SG Pressure setpoint is reached much sooner than the actual steam generator pressure.

Figure SRXB-1.3.7.a-1
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break without Offsite Power Available
Nuclear Power and Core Heat Flux vs. Time

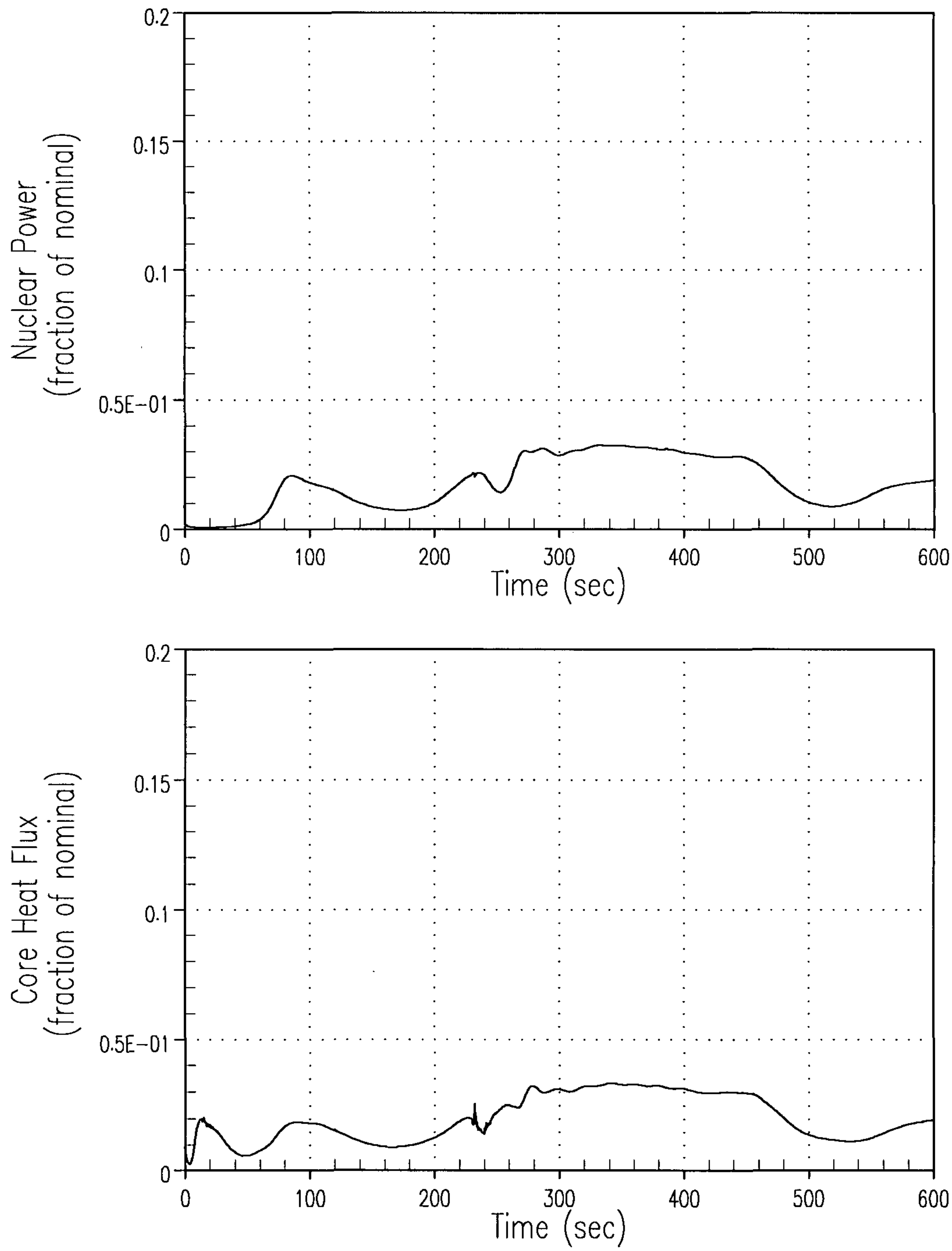


Figure SRXB-1.3.7.a-2
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break without Offsite Power Available
Reactor Vessel Inlet and Core Average Temperatures vs. Time

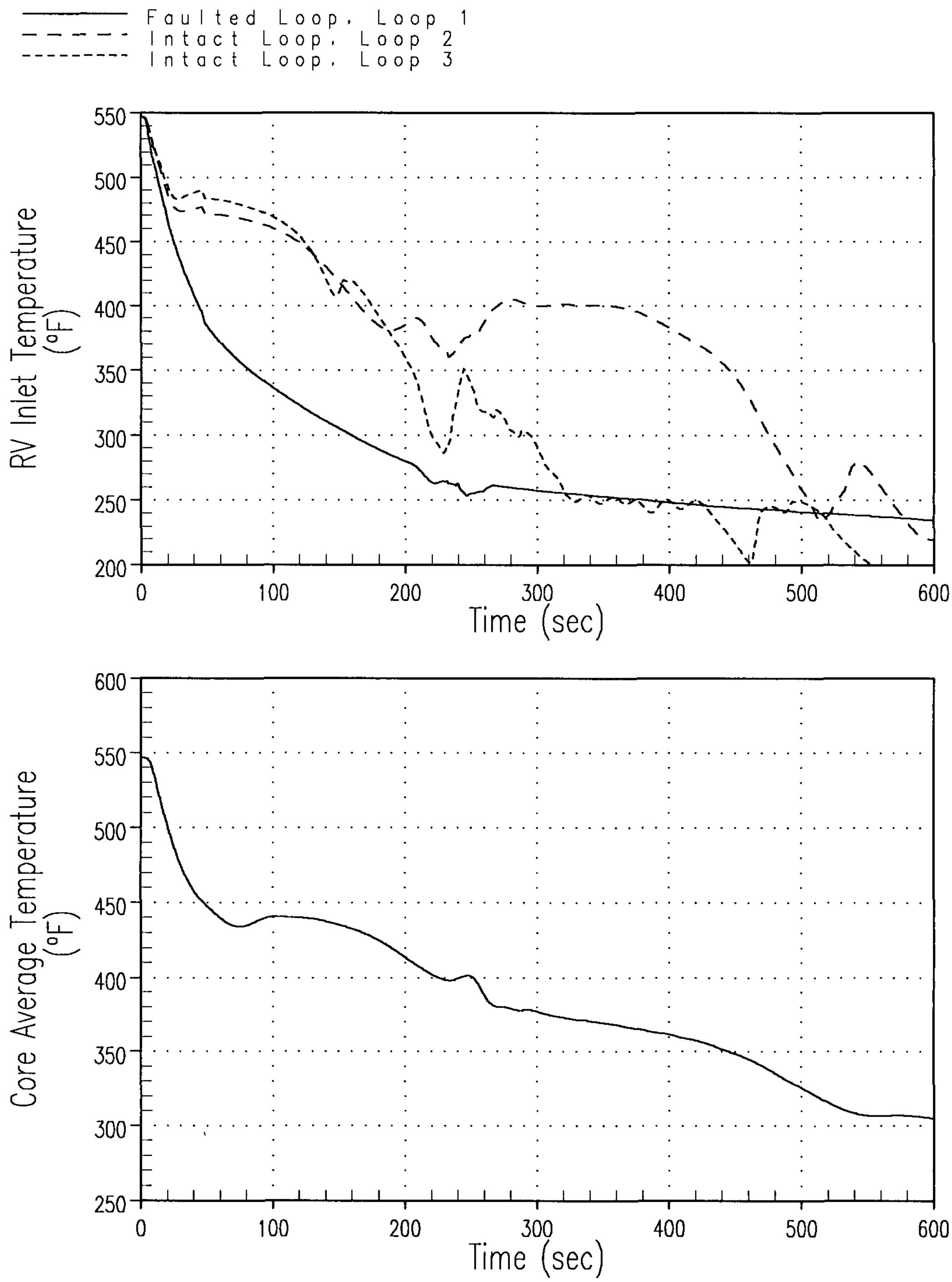
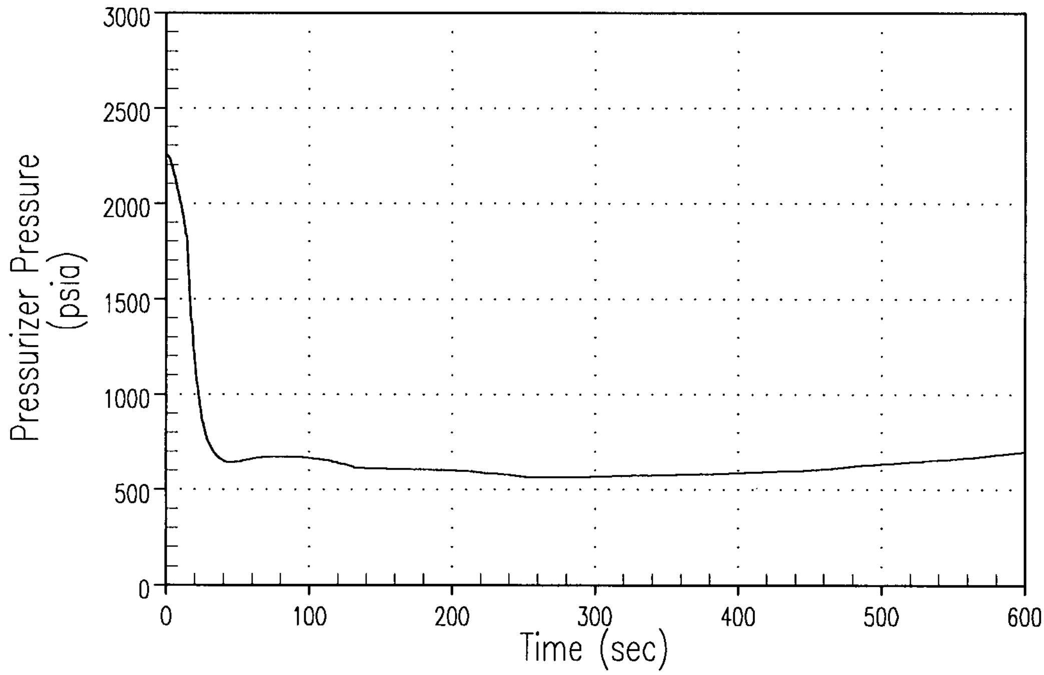


Figure SRXB-1.3.7.a-3
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break without Offsite Power Available
Pressurizer Pressure and Pressurizer Water Volume vs. Time



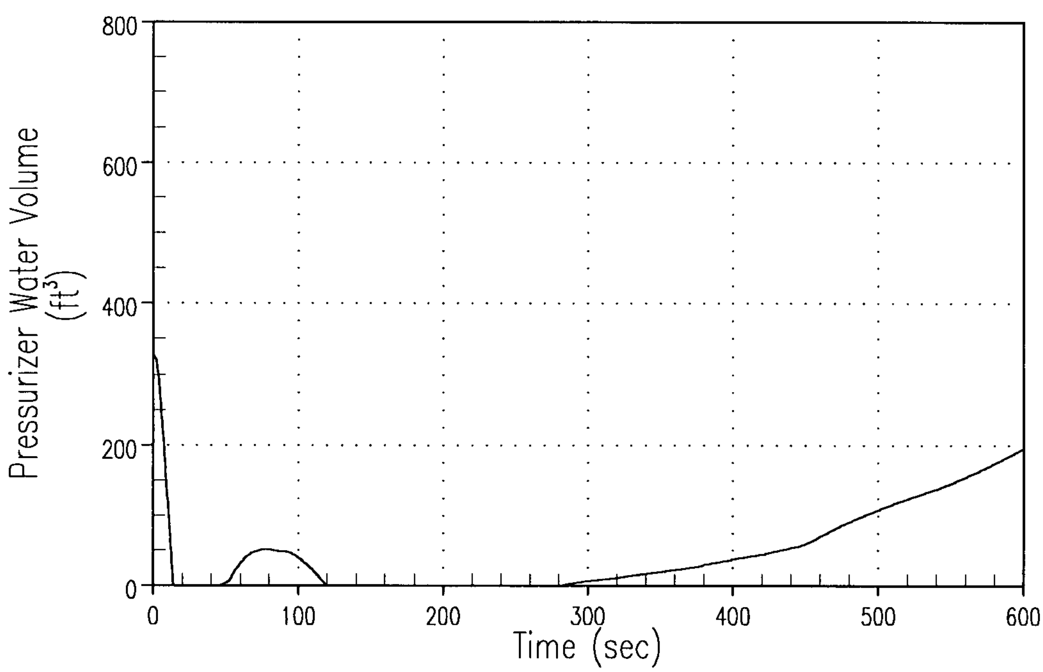
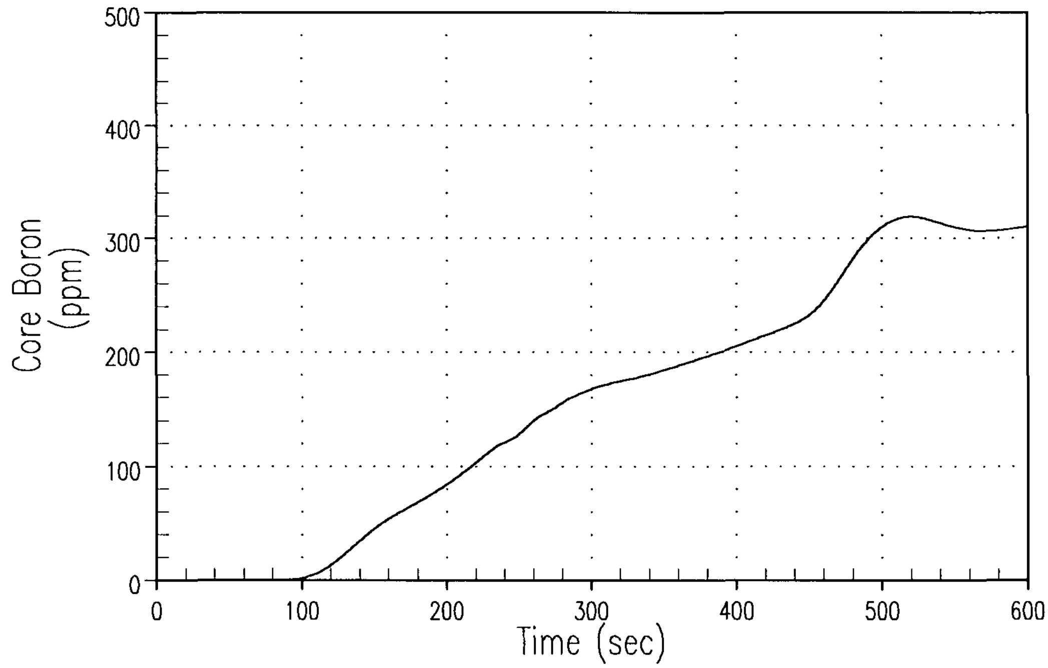


Figure SRXB-1.3.7.a-4
Steam System Piping Failure at Hot Zero Power – 1.388 ft² Break without Offsite Power Available
Core Boron Concentration and Reactivity vs. Time



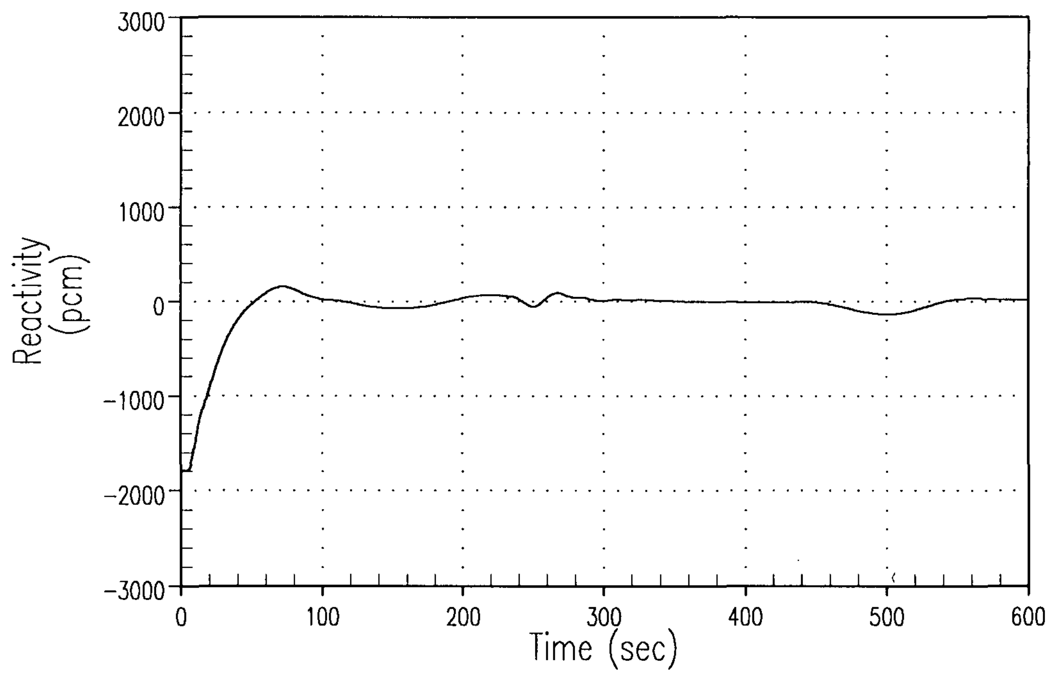
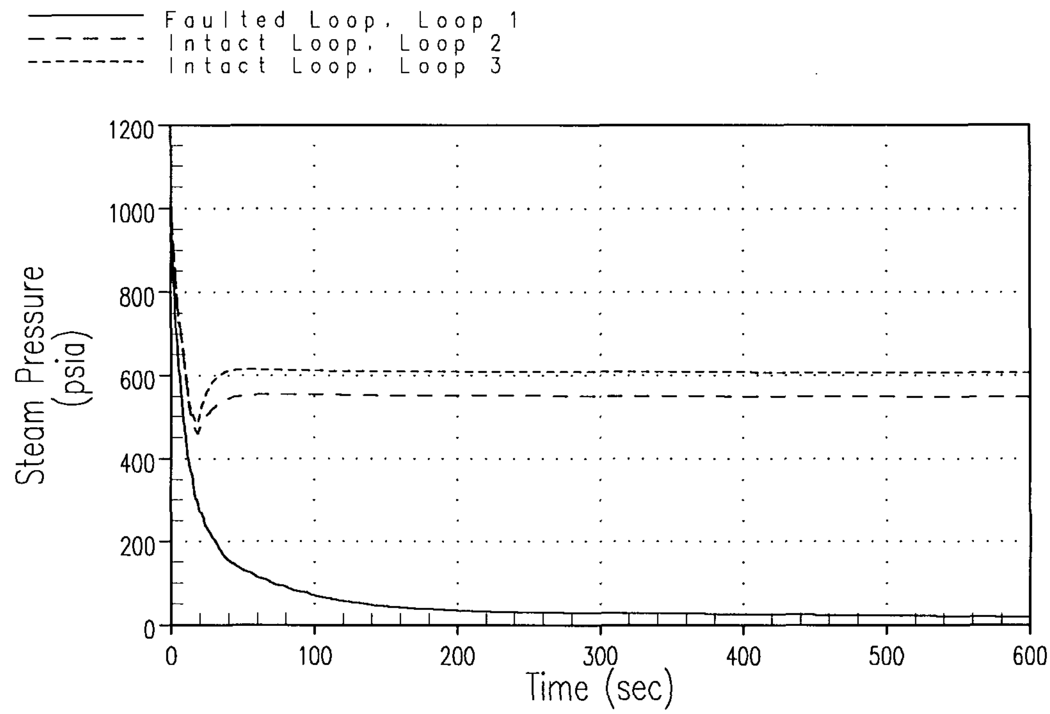


Figure SRXB-1.3.7.a-5
Steam System Piping Failure at Hot Zero Power – 1.388 ft² Break without Offsite Power Available
Steam Pressure and Steam Flow vs. Time



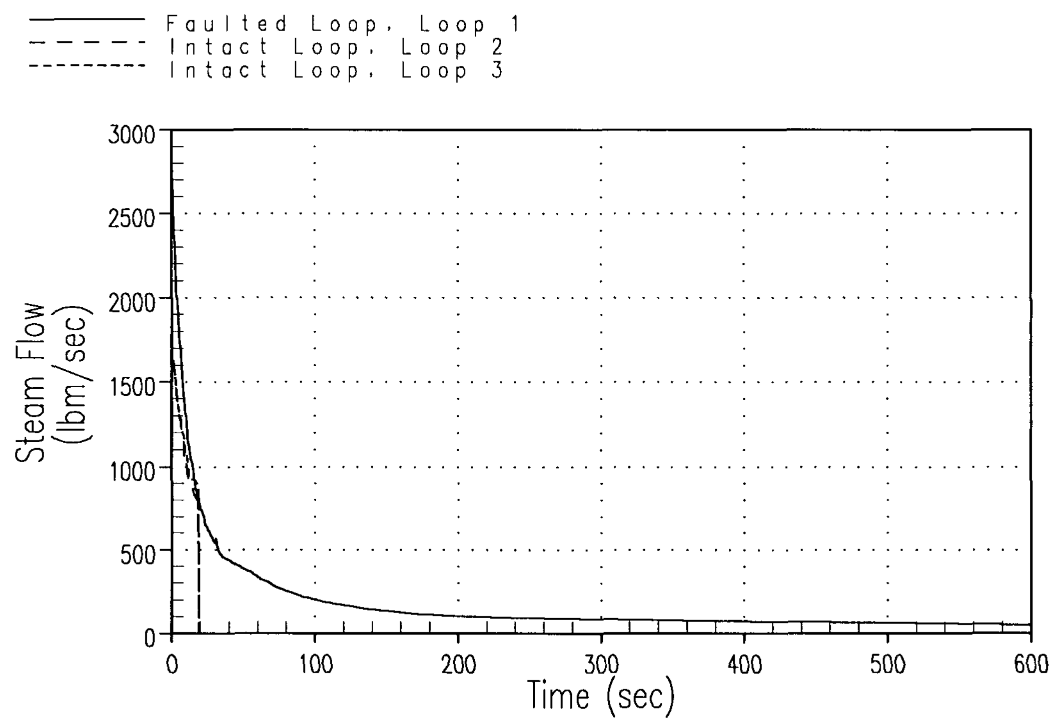
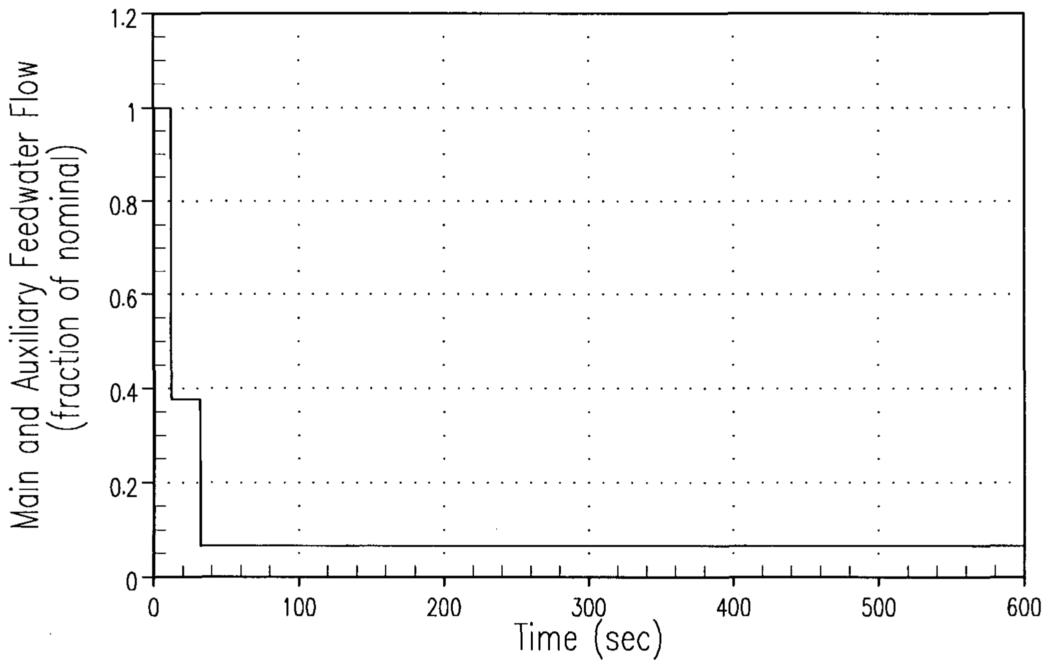


Figure SRXB-1.3.7.a-6
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break without Offsite Power Available
Feedwater Flow and Core Flow vs. Time



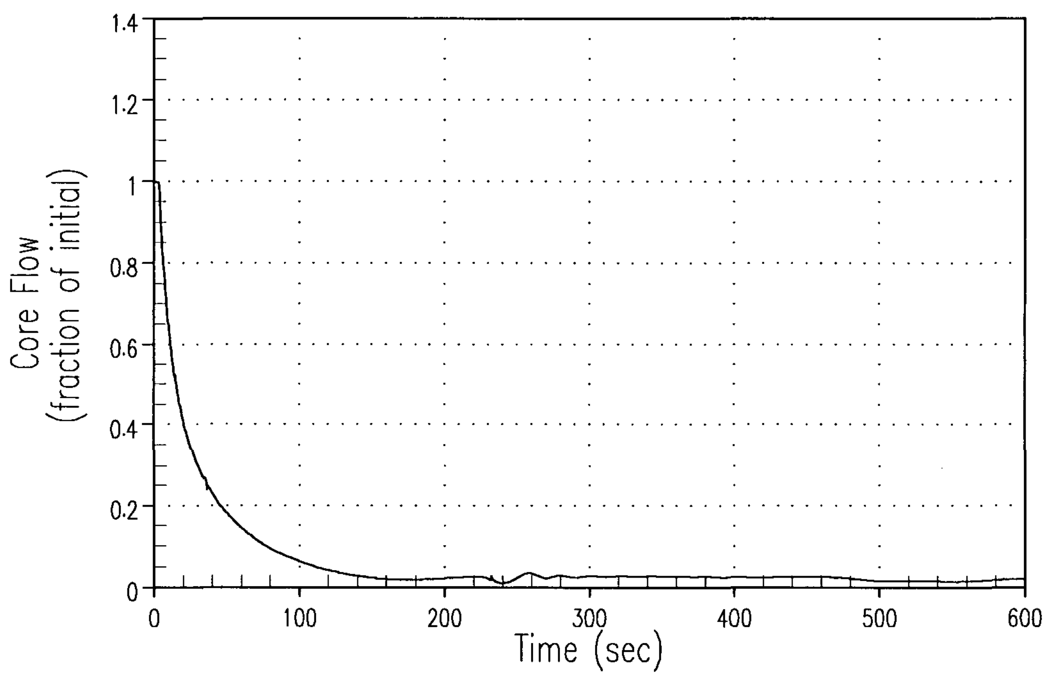
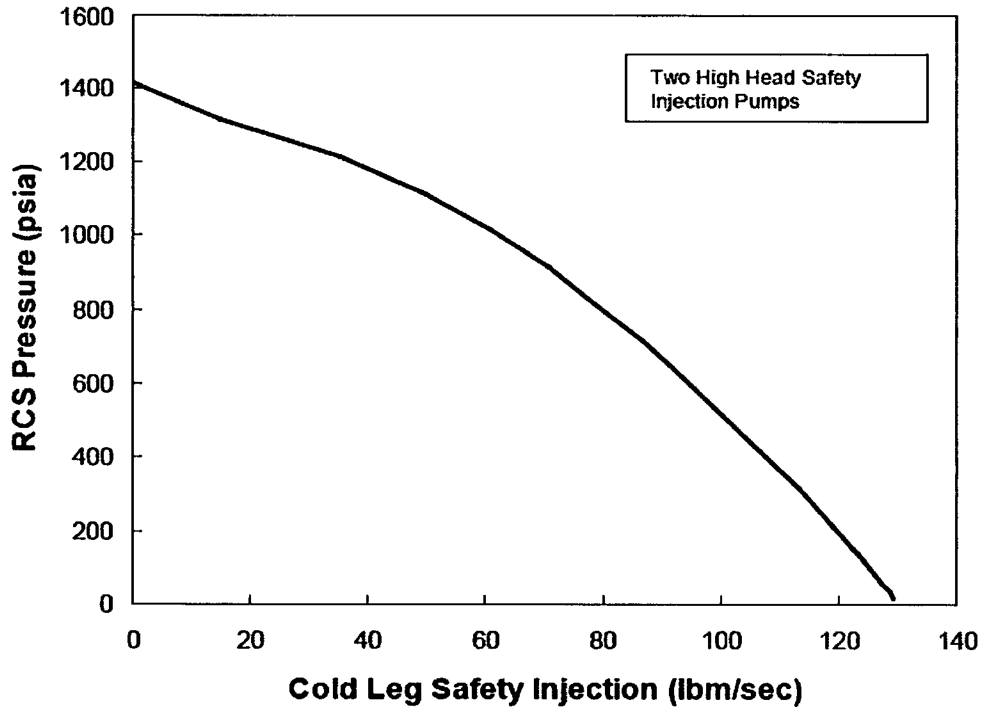


Figure SRXB-1.3.7.a-7
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break without Offsite Power Available
Safety Injection Flow vs. RCS Pressure and Steam Generator Mass vs. Time



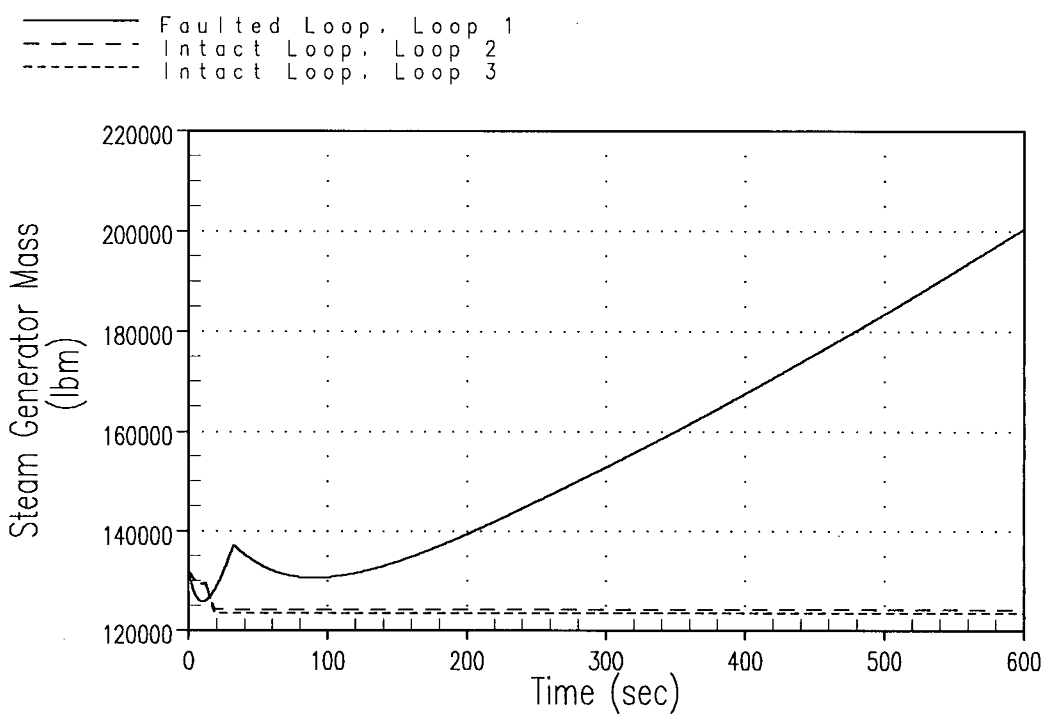
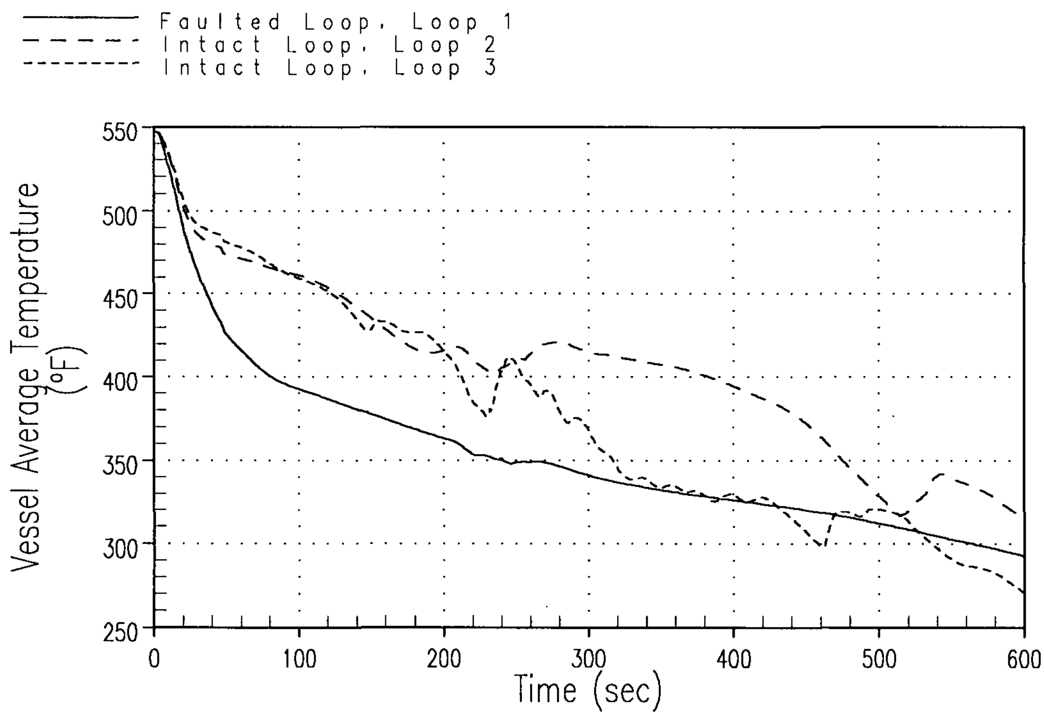


Figure SRXB-1.3.7.a-8
Steam System Piping Failure at Hot Zero Power – 1.388 ft² Break without Offsite Power Available
Reactor Vessel Average Temperature vs. Time



b. **Provide the results of an analysis or evaluation of the major rupture of a steam pipe, at HFP, without offsite power, to show that there is no consequential damage to the fuel or the primary system before the reactor is tripped. If applicable, include a sequence of events table indicating the times and values of peak heat flux and minimum DNBR, and transient plots that are comparable to the reported results of the equivalent steamline break case with offsite power.**

   The loss of offsite power that is typically examined as part of the analysis of a major rupture of a steam pipe from HZP conditions is considered because it is postulated to be a potential consequence of a disruption to the grid following reactor trip. Since the analysis of a major rupture of a steam pipe from HFP conditions is only limiting up to approximately the time of reactor trip and the post-trip phase of the transient is bounded by the analysis from HZP conditions, there was no specific analysis of a major rupture of a steam pipe from HFP conditions without offsite power available.

SRXB-1.3.8 During a major steam line rupture, trip of the main steam isolation valves (MSIVs) and safety injection (SI) system actuation would occur when high steam flow is detected coincident with either low reactor coolant system (RCS) average temperature or low steam line pressure. Actuation of the SI system could also occur when pressurizer low-pressure, or high containment pressure, or high differential pressure between the steam line header and any steam line is detected.

During a credible steam line break, the high steam flow condition would not be reached. Consequently, the MSIVs would not be tripped, and safety injection would not be actuated. Safety injection would be actuated much later, by low pressurizer pressure. In either situation, SI would not be delivered until after the RCS depressurizes to below the SI pump shut off head.

a. **The credible break, with no safety injection or steamline isolation will generate power to match the steam release through the break (i.e., the opening of the largest steam system valve, or about 10%). The peak post-trip power level, for the 1.4 ft2 break, is 13%. Therefore, the credible break is bounded, regardless of the effect of different protection system logic schemes and setpoints. Verify that there is no steam system valve that can relieve more than 13% of nominal steam flow. Explain how the major steam line rupture can be said to bound the credible break when the two events rely upon different protection system actuation logic schemes and response times.**

   Typically, a main steamline depressurization (i.e., credible steamline break) event is defined as an accidental depressurization of the secondary-side resulting from the inadvertent opening of a single steam dump, relief, or safety valve. The maximum relief capacity associated with any one of these valves, even at a typical higher secondary-side operating pressure at Hot Zero Power conditions, would not have the capability to relieve more than 13% of nominal steam flow. In addition, as the transient progresses and the secondary-side depressurizes, steam flow will be reduced, resulting in an overall transient response that is less limiting than that associated with a major rupture of a steam pipe.

   Although the main steamline depressurization event relies on somewhat different protection than a major rupture of a steam pipe to mitigate the event, the overall plant response to each of these events is similar in nature. Specifically, since the RCS cooldown and associated reactivity feedback is the primary concern associated with each of these events, and the major rupture of a steam pipe results in the more severe plant response, it is ultimately the major rupture of a steam pipe event that is examined to demonstrate that the DNB design basis is satisfied.

   The results for the analysis of a main steamline depressurization at Hot Zero Power conditions (i.e., credible steamline break), which are provided in the response to Item "b" below, demonstrate that the results of the main steamline depressurization are bounded by the more limiting results associated with the analysis of a major rupture of a steam pipe.

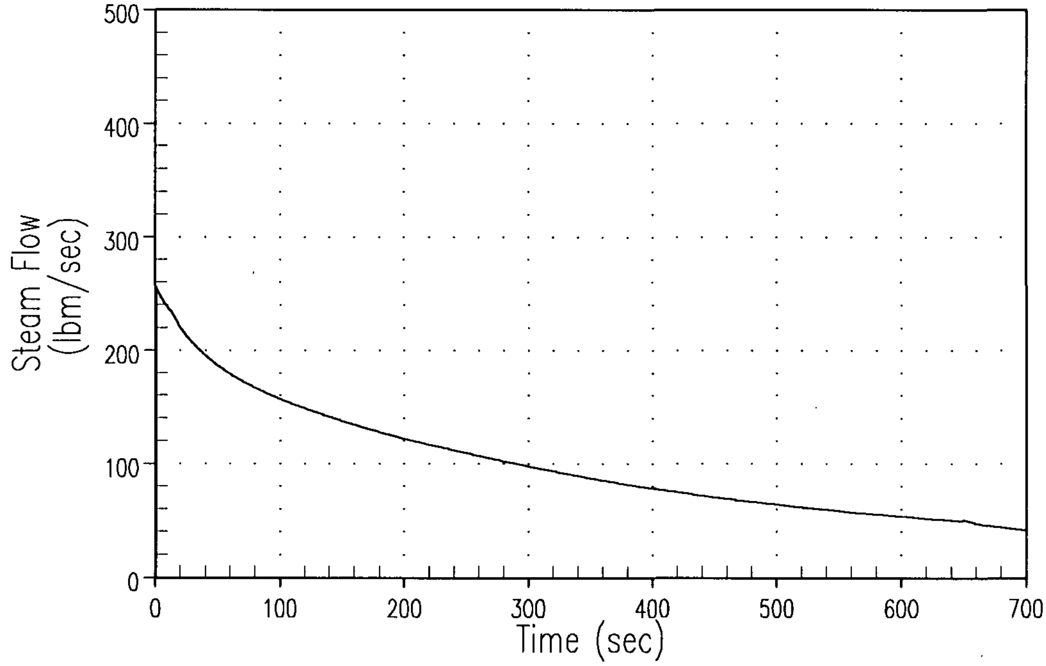
b. Provide the analysis results of a credible steam line break, including a time sequence of events table listing values for peak heat flux and minimum DNBR (if applicable) as well as their times of occurrence. (If question 1 (above) is answered, then this question is withdrawn.)

For the analysis of a main steamline depressurization (i.e., credible steamline break) at Hot Zero Power conditions, steam flow was assumed to initially increase to approximately 8% of the total full power steam flow (approximately 255 lbm/sec at 1000 psia), which bounds the flow increase resulting from the inadvertent opening of any single steam system valve (steam dump, steam relief or steam safety valve). The sequence of events resulting from this analysis is provided in Table SRXB-1.3.8.b; the transient plots for this analysis are provided in Figures SRXB-1.3.8.b-1 through SRXB-1.3.8.b-3. As shown in Figure SRXB-1.3.8.b-2, there was no return to criticality predicted for this event. Therefore, no detailed calculation of the minimum DNBR was performed for the main steamline depressurization analysis.

Table RXB-1.3.8.b: Sequence of Events
Main Steamline Depressurization at Hot Zero Power

	Time reported (sec)
Event	**Without Offsite Power**
Main steam line depressurization occurs in loop 1	0.0
Low pressurizer pressure SI setpoint is reached	143.9
SI actuation occurs	145.9
Main feedwater isolation completed in loop 2 and 3	154.9
SI pumps achieve full speed	166.9
SI flow injection begins (cold leg pressure falls below SI pump shutoff pressure)	167.0
Main feedwater isolation completed in loop 1	175.9
Borated water from the SIS reaches the core	208.0

Figure SRXB-1.3.8.b-1
Main Steamline Depressurization at Hot Zero Power
Steam Flow and Core Average Temperature vs. Time



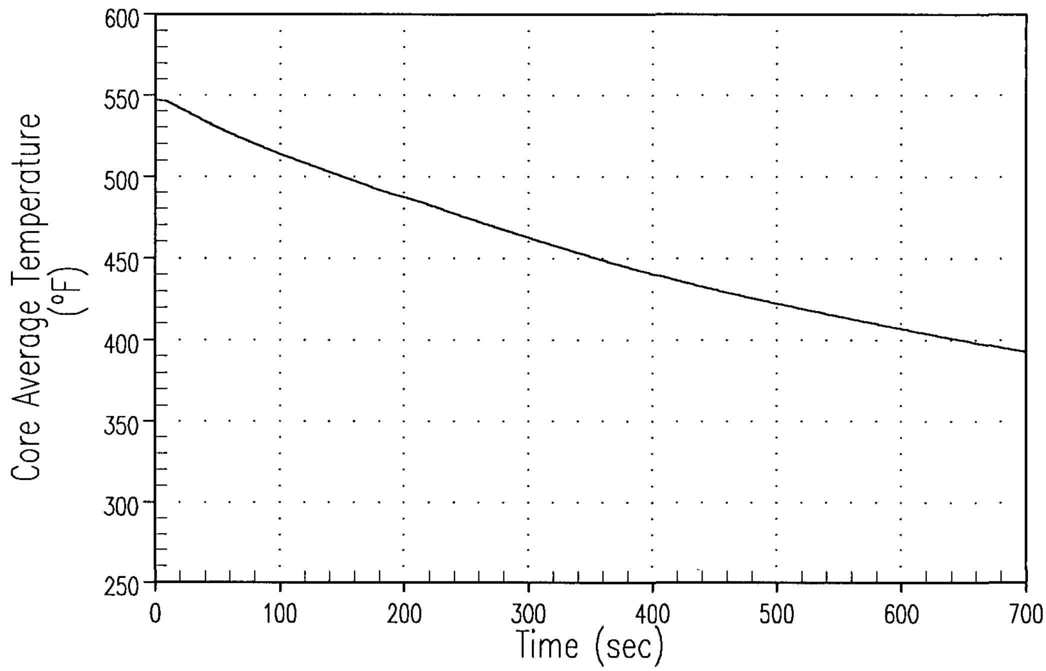


Figure SRXB-1.3.8.b-2
Main Steamline Depressurization at Hot Zero Power
Reactivity and Core Boron Concentration vs. Time

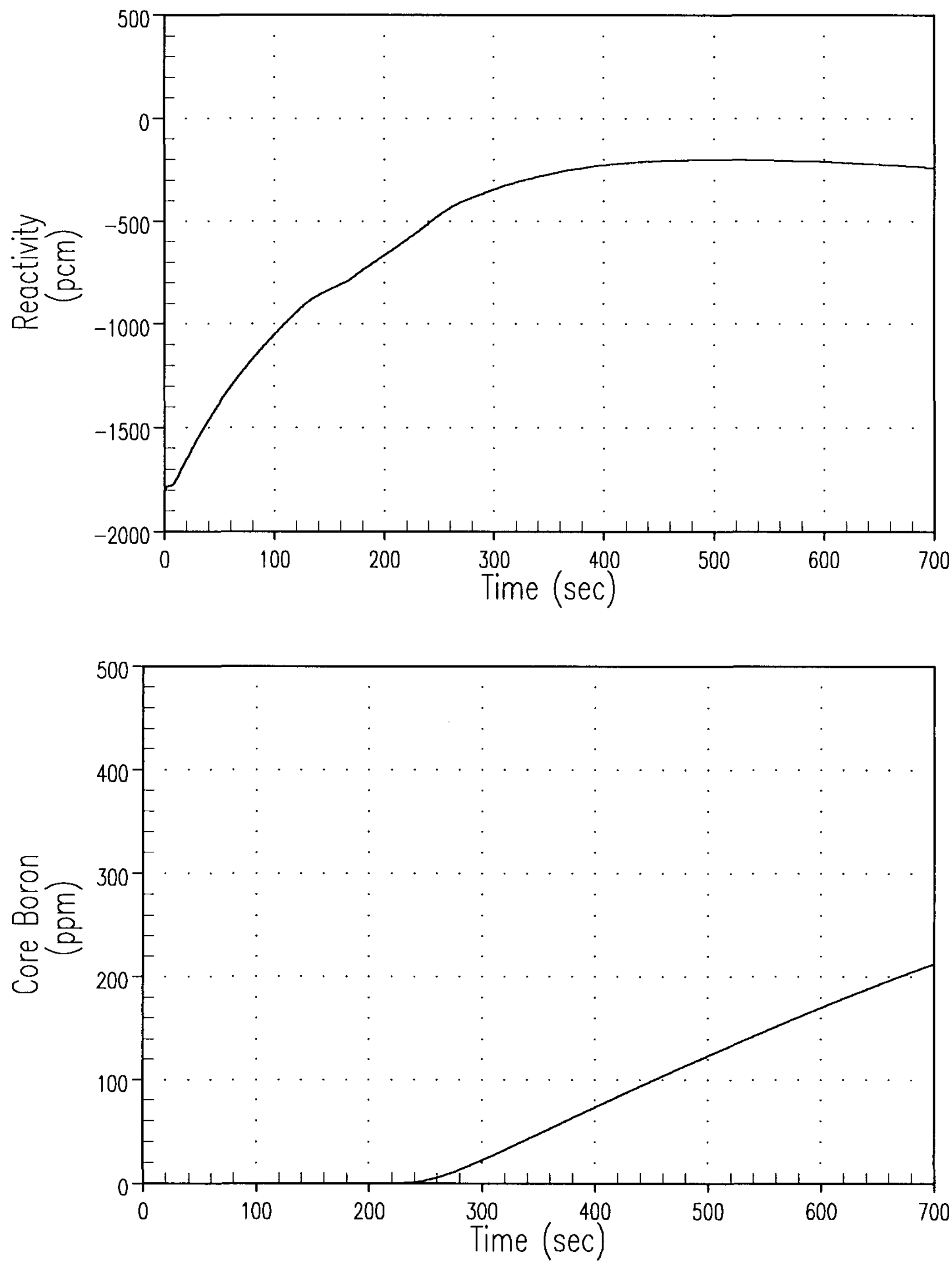
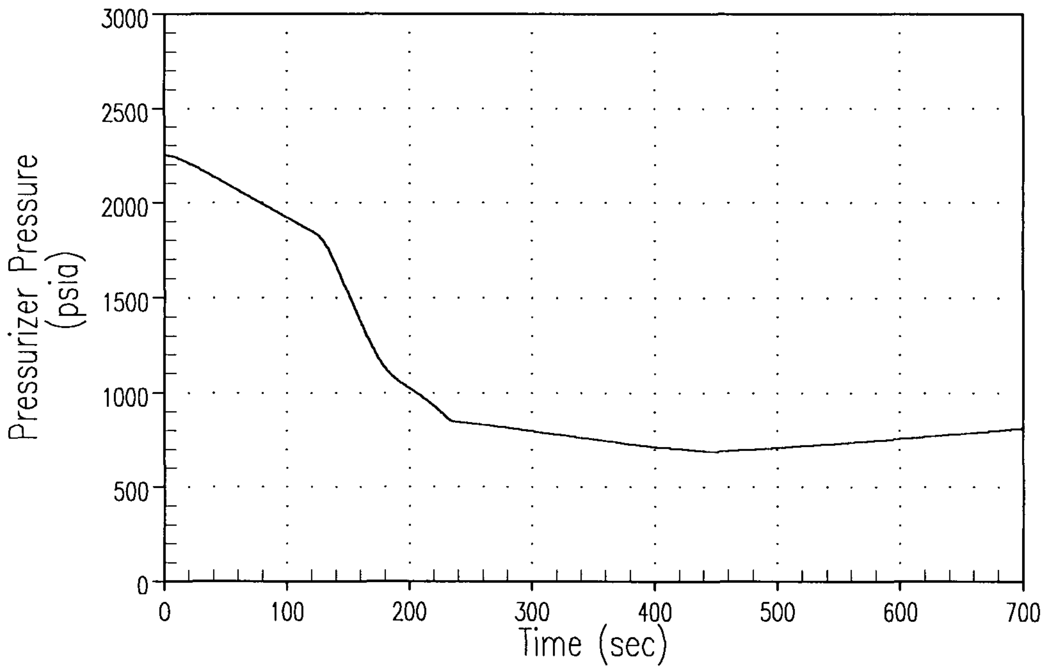
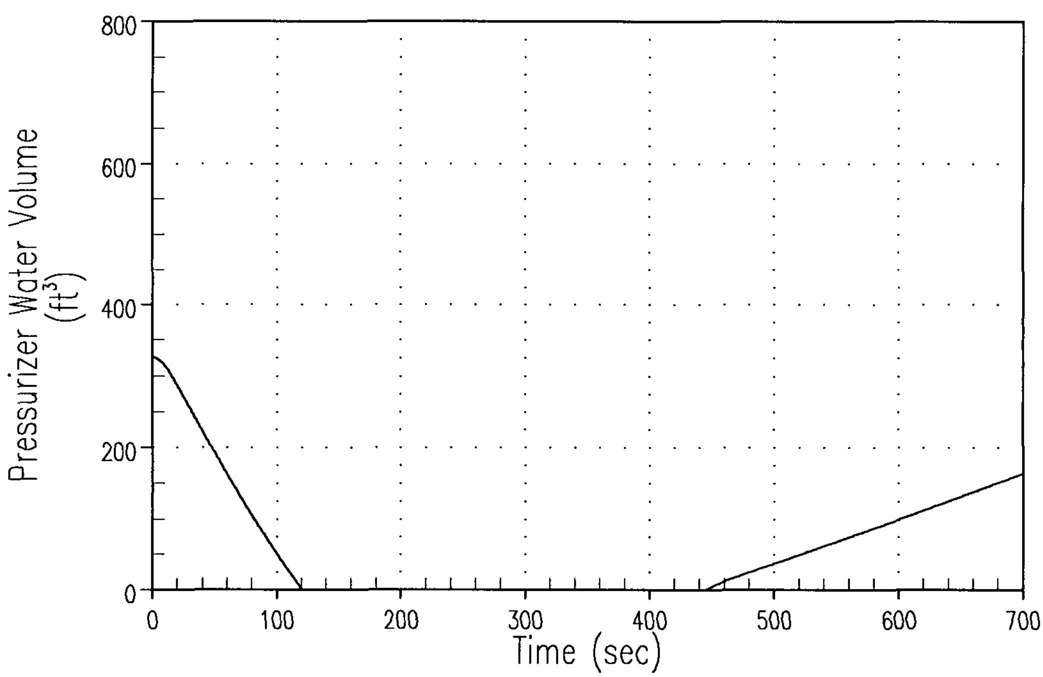


Figure SRXB-1.3.8.b-3
Main Steamline Depressurization at Hot Zero Power
Pressurizer Pressure and Pressurizer Water Volume vs. Time





SRXB-1.3.9 Figure 2.8.5.1.2.2.1-7 depicts the steam generator shell-side mass transient for the faulted and intact loops. Flow from the main feedwater system, which is assumed to be in operation when the plant is at hot zero power (HZP) conditions, and from the auxiliary feedwater system, do not allow the steam generator shell side inventory to drop below about 100,000 lbs. By ten minutes, the steam generator shell side inventory is increasing, due to continued addition of auxiliary feedwater. Describe the procedures and/or trips and/or alarms that would be used by the operator to end the auxiliary feedwater flow at ten minutes. Verify that this action will be accomplished in ten minutes.

A faulted steam generator condition is determined on the basis of either complete depressurization of any steam generator or steam generator pressure decreasing in an uncontrolled manner. After completion of the first four steps [immediate actions] of the Emergency Operating Procedure (EOP) on Reactor Trip or Safety Injection, the EOP instructs the operator to isolate the Auxiliary Feedwater (AFW) flow to the faulted steam generator. The procedural sequence to be followed is similar to that for a ruptured steam generator (steam generator tube rupture). Operator response times have been validated on the simulator and have shown that the action to isolate the AFW can be completed well within a ten minute timeframe.

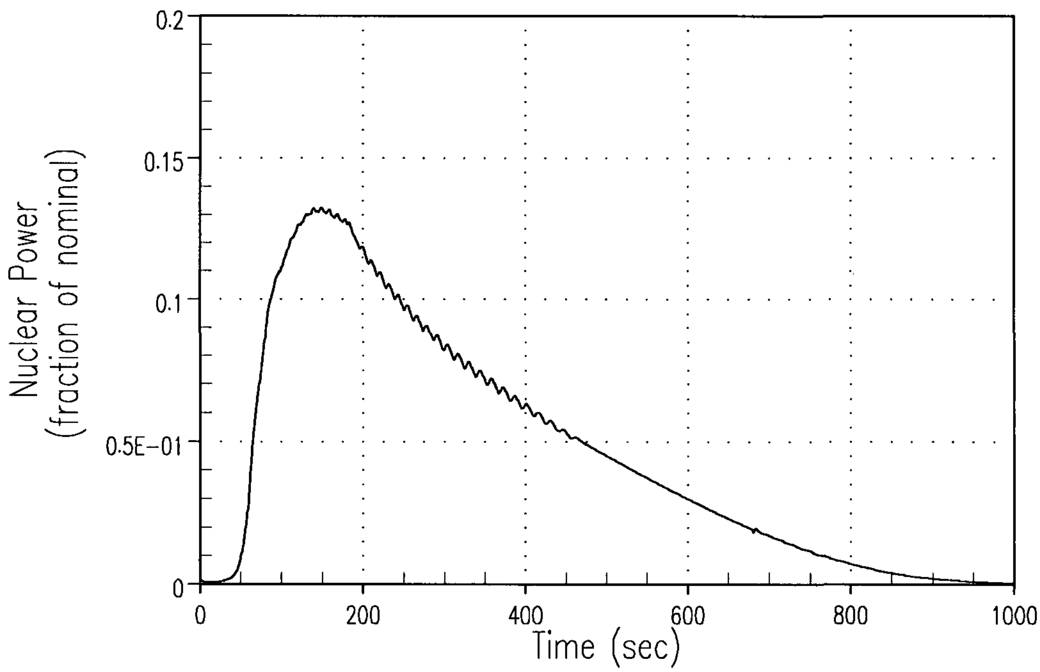
SRXB-1.3.10 Explain the saw tooth shape of the curves in Figures 2.8.5.1.2.2.1-1 and 2.8.5.1.2.2.1-2. If the saw tooth curve shape is due to the size of the time step, used in the analysis, show that reducing the time step does not materially change the results or conclusions of the analysis.

For the analysis of a major rupture of a steam pipe from HZP conditions, it was conservatively assumed that the maximum AFW system flow capacity was being fed to the SG on the faulted loop. This AFW flow assumption was modeled to maximize the RCS cooldown. However, with this highly conservative AFW flow assumption, there is a slight oscillation in the primary-to-secondary heat transfer, causing a corresponding oscillation in the RCS cooldown and associated reactivity feedback, nuclear power and core heat flux responses. If a less conservative (i.e., more realistic) AFW flow response had been modeled, then there would have been less oscillation in the overall plant response. However, this AFW flow assumption would have also resulted in an overall less limiting plant response to the event.

SRXB-1.3.11 Table 2.8.5.1.2.2.1-1 indicates the core becomes subcritical at 186.25 seconds. Why is nuclear power still being generated, at a rate greater than 3%, more than six minutes after the core becomes subcritical?

The negative reactivity insertion resulting from the addition of boron to the core from the SI flow injection does cause the core to become subcritical by 186.25 seconds. However, given the conservatively low boron worth and SI flows assumed, the rate of change of reactivity is relatively slow and it is not until later in the transient that the overall reactivity of the core begins to decrease well below the point of criticality (see Figure SRXB-1.3.11-1). As such, it is also not until later in the transient that nuclear power approaches zero (see Figure SRXB-1.3.11-1). If the addition of boron from the accumulators had also been credited in the analysis, then the overall reactivity and nuclear power response would have decreased at a much faster rate (see Figure SRXB-1.3.11-2).

Figure SRXB-1.3.11-1
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break with Offsite Power Available and without Accumulator Boron Credited Nuclear Power and Reactivity vs. Time



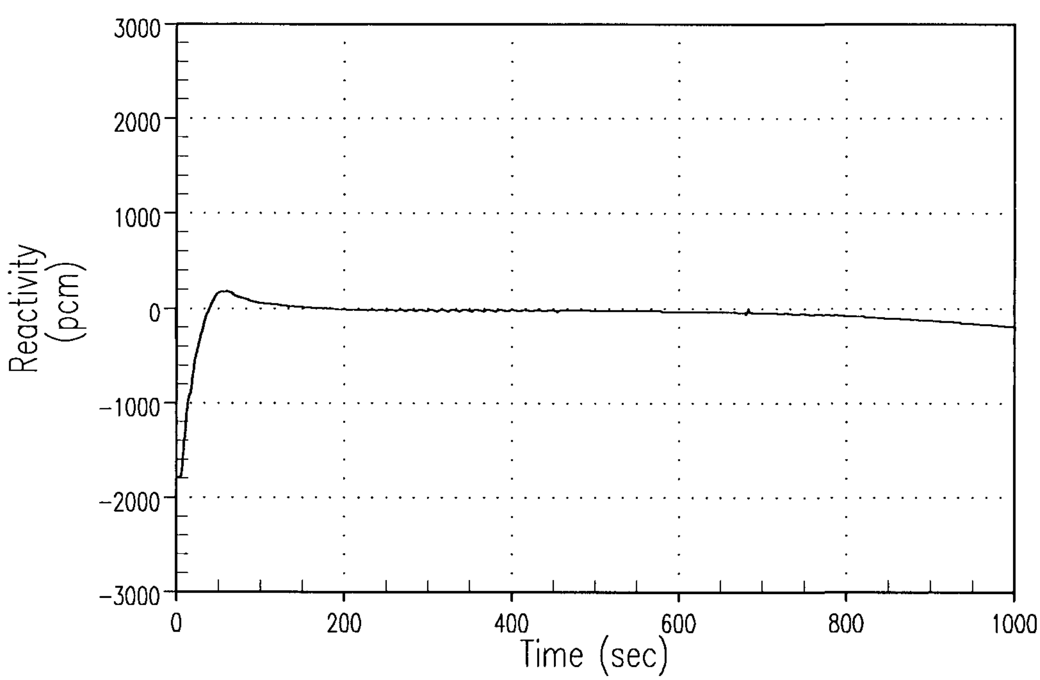
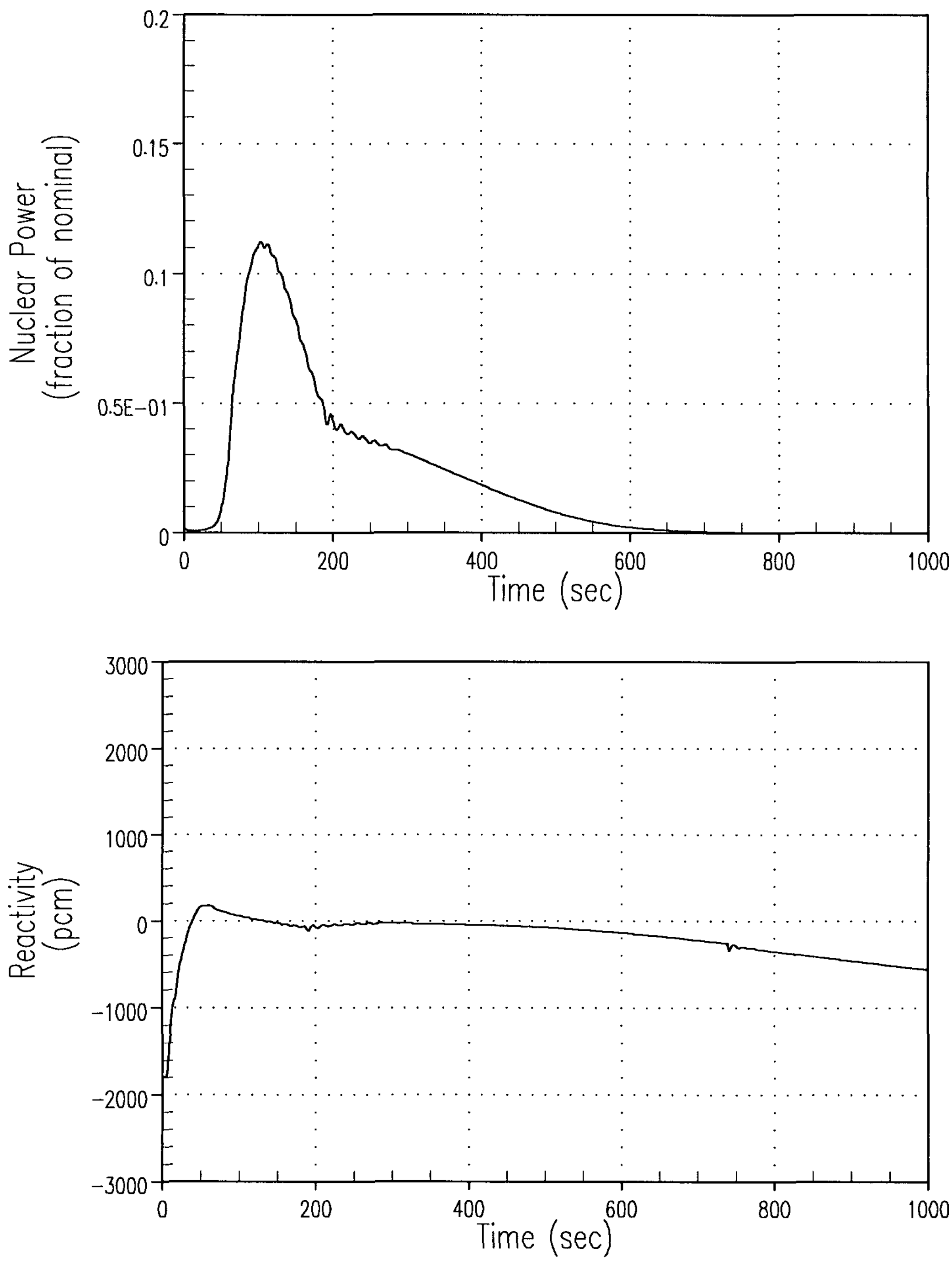


Figure SRXB-1.3.11-2
Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break with Offsite Power Available and with Accumulator Boron Credited
Nuclear Power and Reactivity vs. Time



SRXB-1.3.12 In Figure 2.8.5.1.2.2.2-4, what is steam break flow, and how does it differ from the faulted loop SG outlet steam flow?

The steamline break flow that is presented in Figure 2.8.5.1.2.2.2-4 is the steam flow being blown down through the break, which is modeled to occur on the steamline volume in the faulted loop. This flow is only a portion of the total steam flow from the SG on the faulted loop, as the remaining steam flow from this SG is being fed to the turbine. The steam flow from the SGs on the two intact loops is also being fed to the turbine.

SRXB-1.3.13 Describe, physically, the SG outlet steam flow (about 400 lbm/sec) after the reactor trip in Figure 2.8.5.1.2.2.2-4.

Prior to reactor trip, steam flow from the SGs on the two intact loops is being fed to the turbine and steam flow from the SG on the faulted loop is being both fed to the turbine and blown down through the break on the steamline volume in that loop. However, shortly after the reactor trip, a turbine trip occurs. Therefore, in the portion of the transient after reactor trip, steam flow to the turbine goes to zero and all steam flow from the SG on the faulted loop and the SGs on the intact loops (via the steamline header volume) is blown down through the break.

SRXB-1.3.14 The Turkey Point units have four high head safety injection (HHSI) pumps shared between both units and all four receive the SI signal and begin delivering flow. PTN GDC-4, Sharing of Systems states: "Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public."

a. **Explain how the sharing of HHSI pumps between the two units meets the requirements of PTN GDC-4.**

The licensing basis for Turkey Point is an assumed design basis accident (DBA) on one unit with a loss of offsite power (LOOP) on both units. DBAs in which both the high head safety injection (HHSI) pumps and emergency diesel power supply are required are limited to a loss of coolant accident (LOCA) or a steamline break (MSLB) on one unit coincident with a loss of offsite power to both units. As shown in UFSAR Appendix A, "A Functional Evaluation of the Components of the Systems which are shared by the Two Units," the HHSI pumps serve an emergency function to provide emergency core cooling and reactivity control for LOCA and MSLB, but do not serve a shutdown function for the non-accident unit with a LOOP. As stated in UFSAR Section 6, it is not considered a credible event that both units can simultaneously develop independent and unrelated accident conditions requiring operation of the HHSI pumps. Since simultaneous accidents on both units are not part of the current licensing basis for Turkey Point, HHSI pumps from the opposite unit can be shared. This functional capability demonstrates that for a two unit plant design the safety injection system has the capability to deal with the affected accident unit, without affecting safe control of the non-accident unit; thereby satisfying PTN GDC 4.

b. **If an SI signal is generated in one unit, can it lead to the shutdown of both units?**

An SI signal on one unit does not directly result in shutdown of the other unit. However, if there is a LOCA or MSLB on one unit, with an assumed LOOP as discussed above, the non-accident unit will trip as a result of the LOOP. Additionally, if two of the HHSI pumps are supporting the accident unit, the non-accident unit would have to be shutdown within 72 hours per Action Statements "d" and "e" of Technical Specification 3.5.2, which requires that more than two HHSI pumps be operable for the non-accident unit.

c. **If an SI signal is generated in one unit, what is the destination of the SI flow that is pumped in the other unit?**

If a SI signal is generated on one unit, both units' HHSI pumps will start. As shown in Figure 1.3.14-1, the HHSI pump discharges are cross-connected between the two units. The SI signal opens only the accident unit's cold leg injection valves, so all four HHSI pumps will deliver injection flow to the unit that generated the SI signal. Since the SI signal only opens the accident unit's injection valves, no SI flow is delivered to the non-accident unit.

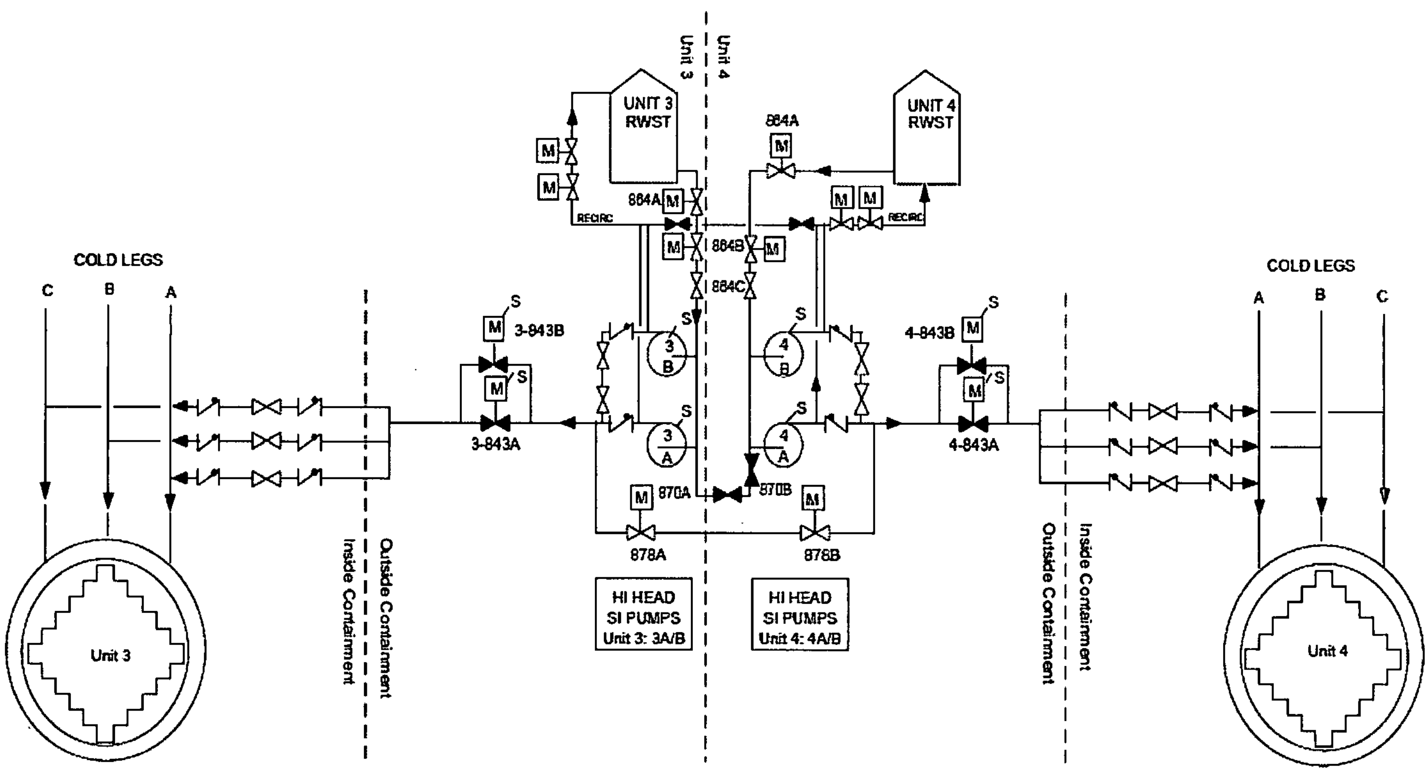


Figure 1.3.14-1 - Simplified sketch of the shared HHSI system. ("S" identifies components that automatically change state on SI signal – i.e., valves open and pumps start)

d. Why are the HHSI pumps assumed to be operating on degraded performance curves? Provide the degraded performance curves. Compare the degraded performance curves to the design performance curves.

The minimum (degraded) performance curve shown in Figure 1.3.14-2 is used in the Emergency Core Cooling System (ECCS) analysis for all four HHSI pumps. The design performance curves for each of the four HHSI pumps are also shown in Figure 1.3.14-2.

The analysis conservatively assumes a minimum (degraded) performance curve to minimize the rate of negative reactivity injected to the core from the higher boron concentration of the Refueling Water Storage Tank (RWST) in the analysis of the Rupture of a Steam Pipe (Licensing Report (LR) Section 2.8.5.1.2) and to minimize core cooling flow in the analysis of Loss of Coolant Accident (LR Section 2.8.5.6.3). The ECCS minimum flow calculation assumptions include identifying the minimum (degraded) performance curve which identifies a lower pump head and flow curve to minimize core flow. The pump minimum (degraded) performance curve is degraded to be consistent with the plant pump surveillance procedures. These procedures account for Emergency Diesel Generator (EDG) underfrequency, pump degradation, etc. The minimum degraded pump curves are analytical limits which establish lower pump performance limits for acceptable operation for the installed plant pumps. There is no regulatory guidance to degrade the minimum performance curve.

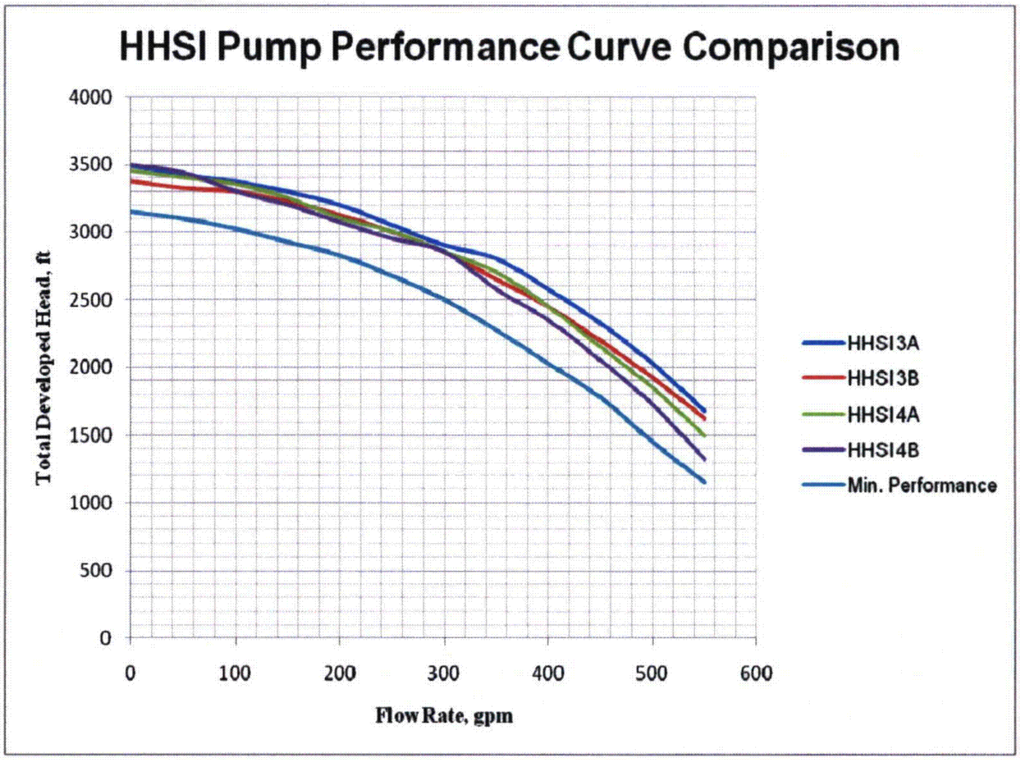


Figure 1.3.14-2

SRXB-1.3.15 If a steam line break were to occur at a location inside containment, at HFP conditions, how would the resulting adverse environment affect the generation of an overpower ΔT reactor trip signal?

The difference between the setpoint value that was assumed in the safety analyses for the K4 term of the Overpower ΔT setpoint equation (1.16) and the nominal setpoint value for this term (1.10), documented in LR §2.4.1.2.3.2.3, includes allowances for both uncertainties and also specifically for the effects of an adverse containment environment. Specifically, a bias is explicitly included in the setpoint value that was assumed in the safety analyses to account for the effects of a breakdown in the signal cable insulation resistance, which introduces an error in the indicated values for hot leg temperature (T_H) and cold leg temperature (T_C) to the racks. In addition, the portion of the Overpower ΔT trip circuitry that is located in containment is qualified for a harsh environment. As such, the analysis of a major rupture of a steam pipe from HFP conditions conservatively accounts for the possibility of a steamline break at a location inside containment and any affect that the associated adverse environment may have on the generation of an Overpower ΔT reactor trip signal.

2.8.5.1.2J Minor steam line breaks (< 1.4 ft2) are said to be bounded by the major steam line break. Show that there is no minor break, larger than a credible break; but too small to cause steam line isolation, that is not bounded by the major steam line break.

Response will be provided later under separate submittal.

SRXB-1.4.1 Confirm whether any operator actions are credited in the analyzed ATWS events described in licensing report (LR) Section 2.8.5.7. If operator actions are credited, justify those actions, including whether they are specified in applicable emergency operating procedures for Turkey Point.

There are no operator actions credited in the ATWS analysis presented in the Licensing Report.

SRXB-1.4.2 Based on NUREG 0800, "Standard Review Plan for Safety Analysis Reports for Nuclear Power Plants," the NRC staff reviews applications to ensure the applicant has demonstrated the capability for long-term shutdown and cooling following an ATWS event. Licensing Report, Figures 2.8.5.7-1 and 2.8.5.7-5 show decreasing nuclear power with respect to time; however power does not reach zero in these figures. Verify that long-term shutdown is reached, and discuss how long-term shutdown is reached.

The nuclear power has not reached zero in these plots due to the decay heat generation in the core. Long term shutdown capability after an ATWS event is discussed in Appendix B of WCAP-8330 (Reference 5) and in Section 9.4 of NS-TMA-2182 (Reference 6, which was the successor to WCAP-8330). There are several mechanisms by which a plant may be shutdown following an ATWS event. These include initiation of Emergency Core Cooling System (ECCS) safety injection, an emergency boration process, a normal boration process, or a manual reactor trip. Additionally, an ATWS Mitigating System Actuation Circuitry (AMSAC) is part of the Turkey Point Units 3 and 4 design which in addition to the requirements of 10CFR50.62 to automatically initiate the Auxiliary Feedwater (AFW) system and trip the turbine, will trip the control rod motor-generator set output breakers which will trip the reactor. This system is described in Section 7.2.4 of the Turkey Point Units 3 and 4 UFSAR. The ATWS analysis presented in the Licensing Report conservatively ignores this trip.

SRXB-1.4.3 Clarify whether significant parameters and inputs to the plant-specific analyses were assumed to be at bounding or nominal values. If the significant parameters were assumed to be at nominal values, provide a justification.

The Turkey Point Units 3 and 4 ATWS current licensing basis analysis and EPU analysis are performed using nominal values for key parameters. The ATWS event is not considered a design basis accident due to the low expected frequency of occurrence. Thus, the use of nominal values and the assumed availability of control and protection systems (except for reactor trip) are appropriate and consistent with the current licensing basis and previous NRC submittals (References 5 and 6).

References

1. M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2010-113), "License Amendment Request No. 205: Extended Power Uprate (EPU)," (TAC Nos. ME4907 and ME4908), Accession No. ML103560169, October 21, 2010.
2. Email from J. Paige (NRC) to S. Hale (FPL), "Turkey Point EPU - Reactor Systems (SRXB) Requests for Additional Information - Round 1.3 (Part 3)," Accession No. ML11202A174, July 21, 2011.
3. M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2011-233), "Response to NRC Requests for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205 and Reactor Systems Issues," August 5, 2011.
4. Email from J. Paige (NRC) to S. Hale (FPL), "Turkey Point EPU – Reactor Systems (SRXB) Request for Additional Information - Round 1.4 (Part 4)", Accession No. ML11213A247, July 29, 2011.
5. WCAP-8330, "Westinghouse Anticipated Transients without Trip Analysis," August 1974
6. Letter NS-TMA-2182 from T. M. Anderson of Westinghouse to Dr. Stephen H. Hanauer of the U. S. NRC, "ATWS Submittal," December 30, 1979.