Florida Power & Light Company, 6501 S. Ocean Drive, Jensen Beach, FL 34957

FPL

Proprietary Information – Withhold From Public Disclosure Under 10 CFR 2.390
The balance of this letter may be considered non-proprietary upon removal of Attachment 2.

January 14, 2012

L-2011-532
10 CFR 50.90
10 CFR 2.390

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Re: St. Lucie Plant Unit 2
Docket No. 50-389
Renewed Facility Operating License No. NPF-16

Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request

References:

(1) R. L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-021), "License Amendment Request for Extended Power Uprate," February 25, 2011, Accession No. ML110730116.

(2) Email from T. Orf (NRC) to C. Wasik (FPL), "St. Lucie 2 EPU – draft RAIs Reactor Systems Branch and Nuclear Performance Branch (SRXB and SNPB)," September 6, 2011.

(3) Email from L. Abbott (FPL) to T. Orf (NRC), "Re: St. Lucie 2 EPU – draft RAIs Reactor Systems Branch and Nuclear Performance Branch (SRXB and SNPB) – Question Numbering," September 28, 2011.

By letter L-2011-021 dated February 25, 2011 [Reference 1], Florida Power & Light Company (FPL) requested to amend Renewed Facility Operating License No. NPF-16 and revise the St. Lucie Unit 2 Technical Specifications (TS). The proposed amendment will increase the unit's licensed core thermal power level from 2700 megawatts thermal (MWt) to 3020 MWt and revise the Renewed Facility Operating License and TS to support operation at this increased core thermal power level. This represents an approximate increase of 11.85% and is therefore considered an extended power uprate (EPU).

A001
NRR

In an email dated September 6, 2011 from NRC (T. Orf) to FPL (C. Wasik) [Reference 2], the NRC staff requested additional information regarding FPL's license amendment request (LAR) to implement the EPU. FPL email dated September 28, 2011 from FPL (L. Abbott) to NRC (T. Orf) [Reference 3], provided specific numbers (SXRB-01 through SRXB-102) for the questions included in the September 6, 2011 email. Attachments 1 and 2 to this letter provide the FPL responses to RAI questions SRXB-40 through SRXB-77, excluding SRXB-71, related to non-loss of coolant accident (non-LOCA) analyses. The remaining responses are being provided in separate submittals.

Attachment 1 contains the non-proprietary responses to RAI questions SRXB-40 through SRXB-77, excluding SRXB-71. Attachment 2 contains the proprietary response to RAI question SRXB-64.

Attachment 3 contains a copy of the Proprietary Information Affidavit. The purpose of this attachment is to withhold the proprietary information contained in the response to SRXB-64 (Attachment 2) from public disclosure. The Affidavit signed by Westinghouse as the owner of the information sets forth the basis for which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of § 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390.

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

This submittal does not alter the significant hazards consideration or environmental assessment previously submitted by FPL letter L-2011-021 [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. Christopher Wasik, St. Lucie Extended Power Uprate LAR Project Manager, at 772-467-7138.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed on 14-January-2012

Very truly yours,

Richard L. Anderson
Site Vice President
St. Lucie Plant

Attachments (3)

cc: Mr. William Passetti, Florida Department of Health

Response to Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information

The following information is provided by Florida Power & Light (FPL) in response to the U.S. Nuclear Regulatory Commission's (NRC) Request for Additional Information (RAI). This information was requested to support the review of Extended Power Uprate (EPU) License Amendment Request (LAR) for St. Lucie Nuclear Plant Unit 2 that was submitted to the NRC by FPL via letter (L-2011-021), February 25, 2011, Accession No. ML110730116.

In an email dated September 6, 2011 from NRC (T. Orf) to FPL (C. Wasik), "St. Lucie 2 EPU - draft RAIs Reactor Systems Branch and Nuclear Performance Branch (SRXB and SNPB)," the NRC staff requested additional information regarding FPL's request to implement the EPU. FPL email dated September 28, 2011 from FPL (L. Abbott) to NRC (T. Orf), "Re: St. Lucie 2 EPU - draft RAIs Reactor Systems Branch and Nuclear Performance Branch (SRXB and SNPB) – Question Numbering," provided specific numbers (SXRB-01 through SRXB-102) for the questions included in the September 6, 2011 email. The non-proprietary responses to RAI questions SRXB-40 through SRXB-77, excluding SRXB-71, are provided in Attachment 1. The remaining responses are being provided in separate submittals.

The response to SRXB-64 contains information that is proprietary to Westinghouse Electric Company (Westinghouse). As such, the non-proprietary response for this RAI is provided below. The proprietary response is provided in Attachment 2.

III. Non-LOCA Transients Analysis and Related Analysis (Attachment 5 of Licensing Report)

SRXB-40 (RAI 2.3.5-1)

Table 2.3.5-2 lists for the station blackout (SBO) analysis the assumed initial conditions including moderator temperature coefficient (MTC) and primary coolant leakage.

Discuss the bases for selecting the values of -0.91×10^{-4} Δρ/°F and 16 gpm for the MTC and primary coolant leakage, respectively. Discuss the reactor coolant pump (RCP) seal break flows assumed, and provide a discussion of an analysis or RCP seal testing data to show adequacy of the RCP seal flow rates assumed in the SBO analysis. The RCP seal testing data should be acceptable to the SL2 RCP seals and SBO conditions extended for at least 4 hours to be consistent with the SBO coping time.

Response

EPU LAR Attachment 5, Table 2.3.5-2 incorrectly listed the moderator temperature coefficient (MTC) for the station blackout (SBO) event as -0.91×10^{-4} Δρ/°F. As indicated on EPU LAR Attachment 5, Table 2.8.2-2 Range of Key Safety Parameters, the correct value for the MTC is -0.91×10^{-5} Δρ/°F.

With respect to the MTC value chosen for the SBO event, a least negative (most positive) MTC value is used. This is consistent with Westinghouse standard methodology for the event. The value input into the RETRAN code is -0.91×10^{-5} Δρ/°F which is a combination of the MTC and a bounding least negative Doppler temperature coefficient (DTC) applicable to the EPU. Since the least negative MTC at hot full power is 0 per EPU LAR Attachment 5, Section 2.8.5.0, Figure 2.8.5.0-6, the corrected MTC value for EPU LAR Attachment 5, Table 2.3.5-2 is equal to the least negative DTC of -0.91×10^{-5} Δρ/°F.

Note that in addition to the normal SBO conditions, the analysis of record (AOR), as documented in Updated Final Safety Analysis Report (UFSAR) Section 15.10, performed a shutdown margin depletion study which resulted in the use of a conservatively high positive MTC during the first

10 seconds of the transient and a conservatively low, most negative, MTC for the duration of the event.

A shutdown margin depletion study was not performed for the EPU based on analysis of the limiting case results for the SBO event. The maximum post-trip reactivity at the end of the event is -4.74$ (-0.03318 $\Delta\rho$). Since the MTC used in the event is 0, this maximum post trip reactivity is a combination of the negative reactivity provided by control rod insertion and the positive reactivity insertion via Doppler feedback. The maximum cooldown in the reactor core is 92°F. Assuming a most negative MTC based on technical specifications limits of -32 pcm/°F, a most negative MTC would contribute 2944 pcm (0.02944 $\Delta\rho$) of positive reactivity. Inclusion of most negative MTC reactivity contribution would result in the reactor remaining subcritical by 374 pcm (0.00374 $\Delta\rho$ or 0.534$).

The total reactor coolant system (RCS) leakage is 16 gpm and is modeled based on the AOR as presented in UFSAR Table 15.10-2. The total RCS leakage remains constant throughout the event and conservatively does not decrease with depressurization. The breakdown of the total RCS leakage is provided in Table SRXB-40-1 below:

Table SRXB-40-1
Total RCS Leakage Breakdown

Component	Assumed Leakage (gpm)
Identified leakage*	
SG tube leakage**	1
Pressurizer safety valve leakage	3
Other identified leakage	6
Unidentified leakage*	1
RCP controlled bleedoff	4
RCP seal leakage	1
Total	**16**

Notes

* Consistent with Technical Specification 3.4.6.2

** This analysis value exceeds the Technical Specification 3.4.6.2 primary-to-secondary leak limit of 150 gallons per day through any one SG, and is conservative to provide margin to account for any leakage increase due to higher pressure differentials under accident conditions.

WCAP-16175-P-A Revision 0, Model for Failure of RCP Seals Given Loss of Seal Cooling in CE NSSS Plants, January 2004, was submitted by Westinghouse to model failures of reactor coolant pump (RCP) seals in a loss of seal cooling scenario for Combustion Engineering (CE) designed plants. This analysis was reviewed and approved by the NRC via the safety evaluation report (SER) dated February 12, 2007 (Accession Number ML070240429). WCAP-16175-P-A contains a discussion on a loss of component cooling water analysis performed for St. Lucie by RCP pump vendor Byron Jackson. The analysis considered seal exposure to water temperature of 550°F at a pressure of 2250 psig for a duration of 100 hours. Seal leakage on the order of 0.25 gpm was observed during the 100 hour analysis. As the SBO analysis performed for the EPU is significantly shorter than the test documented WCAP-16175-P-A and RCS pressure and cold leg temperatures decrease below the test values of 2250 psia and 550°F respectively, the modeling of a total of 1 gpm seal leakage is appropriate.

An additional analysis performed by CE, simulated an 8 hour SBO event to test the upgraded Byron Jackson N-9000 seals, as described in WCAP-16175-P-A. St. Lucie Unit 2 was upgraded to the N-9000 seals in 1999. This analysis simulated depressurization and repressurization in order to model a closer approximation of a typical 8 hour SBO event. Test data from this analysis illustrates that maximum seal leakage observed during this test was approximately 14 gph (0.233 gpm). This test further justifies the use of 0.25 gpm of seal leakage for each RCP.

SRXB-41 (RAI 2.3.5-2)

Page 2.3.5-6 indicates that the RETRAN code is used for the SBO analysis.

Confirm that the RETRAN code is an NRC-approved code for the SBO analysis, and address compliance with each of restrictions and conditions specified in the NRC safety evaluation approving the code for the SBO analysis. Identify any changes and address acceptability of the changes from the NRC-approved version of the RETRAN code for the SBO analysis.

Response

The purpose of the RETRAN code for the station blackout (SBO) analysis is to simulate the nuclear steam supply system (NSSS) thermal-hydraulic response to the SBO event. The SBO event is simulated as a loss of feedwater with a concurrent loss of offsite power event analyzed for an extended period of 4 hours. Table 1 of the safety evaluation report (SER) to the RETRAN-02 report documented in WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999, indicates that the NRC approves the use of the RETRAN code for the loss of main feedwater event, which includes cases with and without offsite power available. No changes to the RETRAN code were required to perform the SBO analysis.

The RETRAN-02 SER limitations were reviewed and the SBO event presented for the EPU is in compliance with these limitations. It should be noted that although voiding appears in the reactor vessel upper head, 7 ft of water remains above the top of the hot legs with a minimum subcooling margin at the hot leg inlets of 26.1°F, and as such, no boiling occurs in the hot legs or the upper portions of the steam generator U-tubes. Natural circulation is maintained and no reflux boiling is present.

SRXB-42 (RAI 2.3.5-3)

Table 2.3.5-1 indicates that, during an SBO event, steam bubble formation would occur in the reactor vessel upper head at about 11,315 seconds following initiation of the SBO event.

Justify that the use of RETRAN is adequate for simulating conditions with bubble formation at the reactor vessel upper head. Discuss the results of the SBO analysis to show that there is no steam bubbles carried into the RCS hot-legs, steam generator U-tubes, RCS cold-legs, down-comer and lower core regions, and that there is no sufficient steam bubbles accumulated at the SG U-tubes to block the natural recirculation flow for decay heat removal.

Response

The station blackout (SBO) analysis presented in EPU LAR Attachment 5, Section 2.3.5 indicates that the upper head voiding occurs at 11,335 seconds, rather than 11,315 seconds as indicated above, due to the pressurizer emptying (EPU LAR Attachment 5, Table 2.3.5-1). At the peak of voiding in the upper head, at the end of the transient, 7 ft of liquid level remains above the top of the hot leg. The minimum subcooling margin observed at the hot leg inlets is 26.1°F. As such, no steam bubbles are carried into the hot legs, U-tubes, cold legs, downcomer and lower core regions. Since no bubbles are present in these regions, natural circulation flow is maintained and a reflux boiling condition is not reached.

The RETRAN code has the ability to model the upper head as a non-equilibrium node, essentially allowing for different steam and liquid temperatures within the region. This is the same model used in the pressurizer and is termed the "non-equilibrium pressurizer option." The non-equilibrium option allows for accurate predictions of conditions in the upper head when voiding occurs. The non-equilibrium option is detailed in the RETRAN-02 topical report WCAP-14882-P-A, approved by the NRC via the SER dated February 11, 1999.

SRXB-43 (RAI 2.3.5-4)

Table 2.3.5-1 includes the SBO sequence of events at EPU conditions.

Specify the non-safety grade systems or equipment used in the analysis specified in the table and justify adequacy of use of them for mitigating the consequences of the SBO. Discuss single failure considered in the analysis. Address acceptability of the setpoints listed in the table for actuating automatic systems or providing signal to the operator to take actions.

Response

In accordance with 10 CFR 50.2, Definitions, the station blackout (SBO) event does not assume a concurrent single failure. As such, no single failure is modeled in the analysis performed for the EPU.

Per Section 15.10.3 of the St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR), the following instrumentation is required to remain functional during an SBO:

- Pressurizer pressure,
- Steam generator (SG) pressure,
- SG level,

- Auxiliary feedwater (AFW) system valve position indication,
- Power operated relief valve (PORV) position indication,
- Containment pressure,
- Containment radiation monitors,
- Battery voltage and current,
- Engineered safety features actuation system (ESFAS),
- AFW actuation system (AFAS), and
- Reactor protective system (RPS) (including hot and cold leg temperature, neutron flux).

The instrumentation presented above, with the exception of the containment pressure and radiation monitors and the instrumentation for battery voltage and current, are considered in the EPU LAR Attachment 5, Section 2.3.5 analysis. The containment and battery instrumentation are not within the scope of the non-loss of coolant accident (Non-LOCA) analysis and thus, are not credited in the event. Additionally, no instrumentation other than those listed above is required to produce the results documented in EPU LAR Attachment 5, Section 2.3.5.

The instrumentation listed above are safety grade with the exception of the AFW system valve position indicator and the PORV position indicator. Since pressurizer pressure does not reach the PORV opening setpoint, the PORV position indicator, while not safety grade, is not relied upon based on the thermal-hydraulic analysis performed for EPU. Additionally, although the AFW system valve position indicator is not safety grade, AFW flow can be successfully confirmed through using the safety grade SG level indication instrumentation.

The following equipment is also required to remain functional during an SBO per UFSAR Section 15.10.3:

- Control element drive mechanisms (CEDMs), condensate storage tank (CST), safety injection tanks (SITs),
- AFW pump 2C,
- Steam supply to AFW turbine driven pump isolation valves,
- AFW flow control valves,
- Atmospheric dump valves (ADVs),
- AFW isolation valves,
- PORVs,
- Main steam safety valves (MSSVs),
- Letdown isolation valves, and
- Turbine stop valves.

The analysis performed for the EPU considers the equipment shown above with the exception of the SITs and PORVs. The reactor coolant system (RCS) pressure does not reach the SIT actuation setpoint in the EPU analysis; thus they are not credited. The pressurizer pressure remains below the opening setpoint of the PORVs; thus the PORVs and associated instrumentation are not credited. Additionally, no equipment other than those listed above is required to produce the results documented in EPU LAR Attachment 5, Section 2.3.5.

The equipment listed above and in UFSAR Section 15.10.3 are safety grade with the exception of the turbine stop valves. Per UFSAR Section 10.3.3, however, the turbine stop valves fail closed and are backed up by the closure of the turbine governor valves. Thus, a failure of a turbine stop valve would still result in steam isolation to the turbine. Closure of the turbine stop valves is modeled in the analysis as early isolation of the steam flow to the turbine results in a more limiting analysis as it places a greater strain on the AFW system, and thus condensate inventory, in removing decay heat from the RCS. Note that the safety grade main steam isolation valves (MSIVs) are fully closed approximately 3 seconds after turbine trip.

Table SRXB-43-1 below presents the components and setpoints shown in EPU LAR Attachment 5, Table 2.3.5-1 and their acceptability for the SBO analysis.

Table SRXB-43-1

Component and Action	Analysis Value	Justification
Low reactor coolant system flow trip	91.9% of thermal design flow	Set equal to a fraction of normalized initial differential pressure corresponding to the nominal low flow trip setpoint of 95.4% minus a 3.5% uncertainty.
First bank of MSSVs open	1000 psia	The nominal MSSV setpoint is used for this event. The nominal opening setpoint is acceptable for this event as biasing to either minimum or maximum opening setpoints would have a negligible effect on the minimum SG inventory and the MSSVs actuate only during the first 30 minutes of the event, at which point pressure is reduced via the operation of the ADVs.
AFW actuation signal	5% SG narrow range span (NRS) level	Set to match the value used in the analysis of record (AOR). An actuation setpoint of 5% SG NRS level is significantly more conservative than the allowable Technical Specifications setpoint of 18% NRS minus the uncertainty of 5% NRS.
AFW flow delay	330 sec	Set conservatively based on inservice testing (IST) acceptance criteria.
AFW flow rate	500 gpm total	Set equal to the flow rate provided by the single turbine driven pump as both electrical driven pumps are assumed to be inoperable during an SBO. The turbine driven pump provides a total of 500 gpm to both SGs.
ADV open by operator action to control SG pressure	900 psia	Set equal to the opening setpoint of the ADVs consistent with the AOR. Operator action of the ADVs is credited 30 minutes into the event to maintain subcooling in the RCS. An opening pressure of 900 psia was chosen consistent with the AOR to mimic steam relief typically provided by the steam bypass control system when normal or offsite power is available.
MSSVs close	995 psia	Set equal to the opening setpoints – 5 psia. Consistent with Westinghouse standard methodology for small blowdowns.

Note that the MSIVs close 26.8 seconds into the event. The MSIV closure setpoint is not a key analysis parameter and although the MSIVs actuate and close, they are not required as indicated by UFSAR Table 15.10-4. The earlier closing of the MSIVs is conservative as it maximizes the heat load to be removed for the event.

SRXB-44 (RAI 2.5.4.5-1)

Page 2.5.4.5-8 indicates that water 154,000 gallons in the condensate storage tank (CST) is required to accommodate the SL2 decay heat removal for removal for 10.63 hour cooldown period including the RCS at hot standby for 4 hours in order to reduce the reactor coolant temperature to shutdown cooling entry condition in the event of loss-of-offsite-power (LOOP).

Provide a discussion of the analysis that determines the CST water of 154,000 gallons for the required cooldown for LOOP conditions, and address the relevancy of the CST water inventory determination for the NCC analysis discussed in Section 2.8.7.2. The information should include a discussion of methods, assumptions, sequence of cooldown events, and single failure consideration for the analysis. Provide justification if non-safety grade equipment is used in the cooldown analysis.

Response

The two EPU LAR Attachment 5 sections noted in the RAI are each associated with the plant's need for condensate, but each has a distinct purpose. EPU LAR Attachment 5, page 2.5.4.5-8 addresses the condensate storage tank (CST) sizing analysis done to calculate the required CST volume for EPU conditions. The CST sizing analysis for EPU conditions results in a required inventory of 154,000 gallons. This is an increased volume from the existing analysis of record (AOR) for the tank sizing. This analysis supports the St. Lucie Unit 2 current CST design, as stated in the Technical Specifications Bases, based on the requirements of NRC Regulatory Guide (RG) 1.139 where hot standby is maintained for 4 hours followed by a cooldown of 75°F per hour.

The natural circulation cooldown (NCC) analysis discussed in EPU LAR Attachment 5, Section 2.8.7.2 addresses the Standard Review Plan guidance as described in Branch Technical Position (BTP) 5-4 to calculate the time to achieve shutdown cooling (SDC) entry conditions and CST inventory usage. Per BTP 5-4, water supply for the auxiliary feedwater system shall have sufficient inventory to permit operation at hot standby for at least 4 hours, followed by cooldown to the conditions permitting operation of the residual heat removal system based on the longest cooldown time with an assumed single failure. The NCC analysis for EPU conditions results in a required inventory of 178,200 gallons.

The CST sizing analysis methodology uses a CENTS computer code cooldown simulation from hot full power conditions to SDC system entry conditions. The CST sizing analysis assumptions are as follows:

a. Plant power is initially at 100.3% of rated power including 0.3% power measurement uncertainty;
b. Maximum cooldown rate of 75°F/hr;
c. Loss of off-site power (LOOP);
d. Limiting single failure of a DC emergency power train;
e. Only safety grade equipment is used;
f. Four hour hold at hot standby followed by cooldown to SDC entry conditions;
g. 1979 ANS 5.1 Standard Decay Heat Curve including long term actinides with 2σ uncertainty;
h. Charging is available following the plant trip;
i. Letdown is disabled;
j. Main feedwater is disabled;

k. Main steam safety valves (MSSVs) provide the initial heat removal path;
l. Two of four atmospheric dump valves (ADVs) are credited;
m. Safety injection system (SIS) is not used;
n. Reactor coolant system (RCS) heat losses to containment are set to zero;
o. Reactor vessel upper head heat losses to containment are set to zero;
p. Main steam isolation valves (MSIVs) are closed upon event start;
q. The auxiliary feedwater (AFW) flow is set to maintain the steam generator (SG) level to match boiloff during the cooldown;
r. SG blowdown is unavailable; and
s. As required, charging is controlled to maintain pressurizer level within the acceptable range.

The limiting single failure of a DC emergency power train, assumption (d), prevents AC power from one emergency diesel generator from being transferred to the onsite electrical system. The single failure disables one train of components associated with the ADVs, AFW system, and SDC system.

The sequence of events for the CST sizing analysis is outlined in Table SRXB-44-1.

Table SRXB-44-1
CENTS CST Sizing Analysis Sequence of Events
75°F/hr Cooldown with Four Hour Hold at Hot Standby

Time (seconds)	Event
1	Reactor trip
	Turbine trip
	Reactor coolant pump (RCP) trip
2,600	Turn off charging flow to maintain pressurizer level
14,000	Turn on one charging pump
14,401*	Set ADVs to manual control
	Initiate cooldown at 75°F/hr
	Turn second charging pump on
15,000	Set AFW flow to 18 lbs/sec per SG
19,000	Turn off one charging pump
27,000	Turn off second charging pump
28,500	Turn on one charging pump
29,000	Turn on auxiliary spray from one charging pump
30,800	Turn off auxiliary spray from one charging pump
	Set AFW flow to 12 lbs/sec per SG
34,000	Turn on auxiliary spray from one charging pump
35,100	Turn off auxiliary spray from one charging pump
	Set AFW flow to 10 lbs/sec per SG
37,400	Turn on auxiliary spray from one charging pump
	Set AFW flow to 8 lbs/sec per SG
38,250	SDC entry conditions achieved
* End of four hour hold period at hot standby.	

The modeling simulation and assumptions are reflective of the AOR, updated for EPU core power.

The analysis supporting EPU LAR Attachment 5, Section 2.8.7.2, the NCC analysis, supports BTP 5-4 and uses the same methodology and limiting single failure as the CST sizing analysis. In addition, the assumptions are the same as described for the CST sizing analysis with the exception of the maximum cooldown rate, 30°F/hr, and initial core power, 100.5% of the uprate core power. These values were conservatively chosen to support the purpose of BTP 5-4, particularly cooldown duration and condensate use.

As described in Section 2.8.7.2, the NCC analysis done to support BTP 5-4 results in a CST inventory usage of 178,200 gallons for EPU conditions. The current NCC CST inventory usage of 276,000 gallons is maintained as the described requirement for EPU as it is bounding of the explicit NCC analysis results for EPU conditions.

The 24,000 gallon difference in CST inventory usage between the NCC analysis done for BTP 5-4 and the CST sizing analysis (178,200 gallons versus 154,000 gallons) is attributed to the differences in the analysis assumptions and the simulation cases. As noted, the differences in the case files are the initial core power and the cooldown rate. Cooldown rate has limited consequential effect on condensate usage; the ADVs typically limit the maximum cooldown rate. The higher initial core power also directly affects the condensate requirements in the NCC analysis. In addition, based on the time that the comparative case runs are terminated, the levels in the steam generator will vary when shutdown cooling entry conditions are achieved. Case data shows that the final CST sizing case run has a lower final SG level than the results for the NCC analysis. The combination of these two considerations address the specific difference in described CST inventory use.

SRXB-45 (RAI 2.5.4.5-2)

Page 2.5.4.5-9 indicates that the IGOR code is used in the analysis of a loss of normal feedwater (LONF) event.

Provide a discussion of the code and address acceptability of the code for the LONF analysis.

Response

IGOR is used as a pre-processor to the Westinghouse version of the RETRAN-02 computer code. IGOR allows the proper definition of the nuclear steam supply system (NSSS) initial conditions and setpoints for the specific transient analysis. The result of IGOR is a partially completed RETRAN NSSS model for the specific transient setup. This model, along with additional transient specific RETRAN input data, creates a completed loss of normal feedwater model to be analyzed with RETRAN. The complete setup of the RETRAN model for the transient is consistent with the NRC approved Westinghouse methodology as documented in WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.

SRXB-46 (RAI 2.8.4.3-1)

Page 2.8.4.3-5 indicates that for the low temperature over-pressurization protection (LTOP) calculations, each energy addition of mass addition event is analyzed at the most limiting initial temperature and pressure and the worst alignment of system components permitted by the Technical Specifications.

Discuss the methods and address acceptability of the methods used in the analysis of the energy addition or mass addition event. Specify the initial values of key plant parameters including temperature, pressure, decay heat model, and time after reactor shutdown for determining the initial decay heat rate assumed in the analysis and justify adequacy of the values used. Discuss assumptions used to maximize a RCS peak pressure. Provide a description of how uncertainties of the RCS temperature and pressure instrument are accounted for determination of the LTOP requirements. List all single failures considered and explain how the worst single failures are determined for use in the analysis. Specify the calculated peak pressures for the analysis of the energy addition and mass addition event, and show how the peak pressures meet the applicable acceptance criteria.

Response

The low temperature overpressure protection (LTOP) analyses for EPU conditions were performed consistent with the current design basis described in the Updated Final Safety Analysis Report (UFSAR) Section 5.2.6. The most limiting LTOP scenarios for mass and energy addition are separately analyzed to show that the reactor vessel (RV) is sufficiently protected from overpressurization by showing that the reactor coolant system (RCS) pressure-temperature (P-T) limits are not violated during an overpressurization event. In addition, the peak transient pressures at the limiting point for each analysis cannot exceed 110% of the design pressure of the shutdown cooling (SDC) system per the American Society of Mechanical Engineers (ASME) Code, Section III, Article NC-7000. The methods used in each LTOP analysis are acceptable because appropriate conservatisms are applied in each analysis to generate conservatively high peak transient pressures.

The most limiting transients initiated by a single operator error or equipment failure are:

1. An inadvertent safety injection actuation (mass addition).
2. A reactor coolant pump (RCP) start when a positive steam generator (SG) to RV temperature differential exists (energy addition).

The transients were determined as most limiting by conservative analyses which maximize mass and energy additions to the RCS. In addition, the RCS is assumed to be in a water-solid condition at the time of the transient.

The mass addition overpressurization event analysis considers two worst case scenarios:

1. Two high pressure safety injection (HPSI) pumps and three charging pumps at temperatures greater than 200°F.
2. A single HPSI pump and three charging pumps at temperatures less than or equal to 200°F.

Initial pressurizer pressure is conservatively assumed to be a bounding low pressure of 300 psia, and is increased until a maximum or equilibrium pressure is reached. The 300 psia value is based on the anticipated range of equilibrium pressures. The mass addition analysis conservatively accounts for RCS volume expansion contributions from decay heat and the full capacity of the pressurizer heaters. A bounding minimum RCS volume is conservatively used. Uncertainty of 0.3% is applied to the core power to maximize the core power used in the calculation of decay heat. Bounding generic decay heat fraction data in conjunction with a maximum allowable cooldown rate is used to minimize time after shutdown, which in turn maximizes decay heat energy input. The minimum temperature is assumed for the start of cooldown, and the maximum cooldown rate is assumed in order to minimize the time period from the start of reactor shutdown, conservatively maximizing the decay heat. The maximum pressurizer heater capacity is used, and it is assumed that a single failure occurs and only one of the two SDC system relief valves is operable during the overpressurization event. A maximum temperature which bounds the initial heatup temperature including instrument uncertainty is conservatively used for heatup and a minimum temperature which bounds the initial cooldown temperature and includes instrument uncertainty is conservatively used for cooldown. Determination of peak transient pressure conservatively accounts for the time delay in power operated relief valve (PORV) opening, instrument loop uncertainty, and PORV lift setpoint uncertainty.

The energy addition overpressurization event analysis considers a RCP start with an initial SG to RV temperature differential conservatively maximized to the Technical Specifications limit, which is greater than the differential temperature limit in the emergency operating procedure. The energy addition overpressurization event analysis considers worst single failure cases where a single PORV or a single SDC system relief valve provides overpressure protection. Initial RCS temperature and pressure are conservatively assumed to be at bounding maximum levels for conditions prior to the initiation of shutdown cooling. Initial pressure bounds the pressurizer pressure including instrument uncertainty. Initial temperature bounds LTOP enable temperatures for both heatup and cooldown, including instrument uncertainty. PORV opening pressure is increased from the nominal setpoint by accounting for setpoint uncertainty, instrument loop uncertainty, and pressure accumulation due to finite PORV opening time to conservatively maximize the RCS pressure at the PORV opening. Instrument loop uncertainty is accounted for in the SDC initiation pressure to conservatively maximize this value. The decay heat rate is determined based on a conservative maximum temperature and maximum core power including uncertainty. The heat addition also accounts for heater power and RCP heat input.

PORV and SDC system relief valve setpoints and peak pressures from the mass and energy addition LTOP analyses are shown in Table SRXB-46-1.

Table SRXB-46-1
PORV and SDC System Relief Valve Peak Transient Pressures for LTOP Analyses

Event	Description	Peak Transient Pressure (psia)	Setpoint (psia)
Mass Addition	PORV setpoint (1 HPSI and 3 charging pumps)	531	490
	PORV setpoint (2 HPSI and 3 charging pumps)	586	490
	SDC system relief valve setpoint (1 HPSI and 3 charging pumps)	368	350
	SDC system relief valve setpoint (2 HPSI and 3 charging pumps)	387	350
Energy Addition	PORV setpoint	502	450
	PORV setpoint	522	470
	PORV setpoint	542	490
	SDC system relief valve setpoint	368	350

The peak pressures shown in Table SRXB-46-1 are evaluated to identify the controlling pressures and applicable temperature ranges. The controlling pressures are the maximum transient pressures of all applicable transients in a particular temperature region. The controlling pressures are compared to the P-T limit curves to show that the P-T limits are not violated during the LTOP transients and the reactor vessel is protected from overpressurization.

The SDC system relief valve setpoint is set to protect the SDC system from exceeding the maximum allowable SDC system design pressure. In accordance with ASME Code, Section III, Article NC-7000, the peak pressure is acceptable if it does not exceed 110% of the SDC system design pressure. Table SRXB-46-2 shows that the peak transient pressures at the limiting point of the SDC system are within acceptable limits for each event.

Table SRXB-46-2
SDC System Peak Transient Pressures for LTOP Analyses

Event	Peak Transient Pressure (psia)	Maximum Allowable Pressure (psia)
Mass Addition	389	400
Energy Addition	380	400

SRXB-47 (RAI 2.8.4.4-1)

Section 2.8.4.4.2.5 discuss the results of the analyses for (1) the normal plant cooldown duration, (2) Appendix R safety shutdown cooldown within 72 hours, and (3) the TS required cooldown within 36 hours.

Discuss for the above three analyses the methods used and address acceptability of the methods. Discuss for each analysis the assumptions and values used for key parameters and show that the assumptions and values meet the TS requirements and are conservative, resulting in a longest time for the required cooldown.

Response

Shutdown cooling (SDC) system analyses are performed for a normal two train cooldown scenario and a single train emergency cooldown scenario. The time required for cooldown following natural circulation and to cool the plant from hot standby to cold shutdown conditions following the SDC system initiation are also analyzed. A description of the assumptions and key parameters for each SDC system analysis scenario is provided in Table SRXB-47-1.

Table SRXB-47-1
SDC System Cooldown Scenarios

Scenario	Description
Normal Cooldown	• Cooldown from SDC entry conditions to cold shutdown conditions • Normal plant conditions • No single failure assumed • Two available trains of SDC system • SDC system initiated 3.5 hours after shutdown
Emergency Cooldown	• Cooldown from SDC entry conditions to cold shutdown conditions • Normal plant conditions • One available train of SDC system • Cooldown with most limiting failure • SDC system initiated 3.5 hours after shutdown
10 CFR 50 Appendix R Cooldown	• Cooldown from SDC entry conditions to cold shutdown conditions • Plant fire assumed • Parametric study based on start time • Single failure assumed (diesel generator) • One available train of SDC system • SDC system initiated from 10 to 80 hours after shutdown*

Note
* Assumptions used to determine the time to reach SDC system initiation time for the 10 CFR 50 Appendix R cooldown analysis are discussed below.

SDC system analysis scenarios have the following additional conservative assumptions:

- Replacement steam generator (RSG) metal mass and water volume are included in the reactor coolant system (RCS) metal heat capacity and water volume;
- 10% steam generator tube plugging is assumed for the SDC heat exchanger. (This assumption conservatively increases the cooldown time compared to the cooldown time based on the full SDC heat exchanger effective area); and

- No credit is taken for convective heat losses from piping or equipment.

In addition, a minimum component cooling water (CCW) shell side flow is conservatively used. A maximum CCW inlet fluid temperature is conservatively used at the start of the cooldown for all SDC system analyses. For the 10 CFR 50 Appendix R cooldown analysis, the maximum CCW fluid temperature is conservatively used for the duration of the analysis. The 10 CFR 50 Appendix R cooldown analysis conservatively uses a cooldown rate of 25°F, a lower cooldown rate than the maximum allowable cooldown rate in order to generate a conservatively long cooldown time. The cooldown analysis also accounts for RCS temperature instrument uncertainty.

To support the 10 CFR 50 Appendix R analysis, in order to show that the cumulative time from reactor trip to cold shutdown is less than 72 hours, an analysis is performed to determine the longest time to reach SDC system entry conditions. The following conservative assumptions are used to determine the longest time to SDC system initiation:

- The RCS charging system requires two hours for initiation.
- The plant requires an additional two hours to align the SDC system.
- The maximum cooldown rate is 25°F per hour, which is lower than the maximum cooldown rate.
- The cold shutdown temperature is reduced by 3°F to 197°F.
- Only one atmospheric dump valve (ADV) and one feedwater pump are available for cooldown from hot standby to hot shutdown.
- The condensate storage tank (CST) inventory temperature is 120°F.
- There is a hold time to allow the reactor vessel upper head to reach saturation temperature once hot shutdown is achieved.
- Cold leg temperature measurement uncertainty is applied.
- No credit is taken for heat removed by the ADV.
- Liquid and metal masses of the primary and secondary plant are included as part of the heat capacity with no heat loss to the environment.

To support the Technical Specifications analysis, it is demonstrated that at EPU conditions, the plant reaches SDC system entry conditions in less than 36 hours when a cooldown rate lower than the maximum allowed cooldown rate is conservatively assumed. One train of SDC system equipment is then placed in operation. The additional time to reach cold shutdown conditions is determined using the SDC system initiation time with a parametric analysis of the time to cool the plant from hot shutdown to cold shutdown as a function of the SDC system initiation time. The parametric analysis provides this information for SDC system initiation times of 10 hours to 80 hours following reactor trip. Using the calculated SDC system initiation time which falls within this time range, it is determined that 200°F is achieved in approximately 10 additional hours. Therefore, continued compliance with the 10 CFR 50 Appendix R cold shutdown (Mode 5) requirement within the 72-hour timeframe is demonstrated at EPU conditions.

<u>SRXB-48 (RAI 2.8.5.0-1)</u>

Page 2.8.5.0-16 shows that for the analysis of the loss of condenser vacuum (LOCV) event, the initial pressurizer water level of 66% of the span is used for the overpressure and DNB case. The results of both cases shows that the peak pressurizer water remains below the total volume of the pressurizer (pages 2.3.5.2.1-6 and 2.8.5.2.1-7), resulting in no pressurizer overfill to occur.

Explain why the maximum initial value of 71% span (specified as the upper limit of 68% in TS 3.4.3 with uncertainty of 3%) is not used to minimize the margin to the pressurizer overfill. Also, discuss the values of the initial SG water level used in both overpressure and DNBR cases for SG overfill consideration. The information should include a discussion of the effect of measurement uncertainties, and SG water mass addition due to turbine runback on the maximum SG initial water level assumed in the LOCV analysis. Provide justification if the maximum initial SG water level is not used to minimize margin to the SG overfill. This RAI is also applicable to the uncontrolled control rod assembly withdrawal at power event (page 2.8.5.4.2-9) and asymmetric SG transient analysis (page 2.8.5.2.5-5) while pressurizer and SG overfill may occur.

<u>Response</u>

An initial pressurizer level of 66% span is assumed for the loss of condenser vacuum (LOCV) event. This consists of the nominal pressurizer level of 63% span plus 3% uncertainty. This is consistent with the analysis of record (AOR) documented in Updated Final Safety Analysis Report (UFSAR) Section 15.2.3. Furthermore, the assumption of nominal pressurizer level plus uncertainty is consistent with standard Westinghouse methodology for the LOCV event. The LOCV event is the limiting Chapter 15 analysis with respect to reactor coolant system (RCS) pressure. As such, the event is modeled such that the peak pressure can be obtained. A maximum possible initial pressurizer level is not chosen for this peak pressure case since starting at a higher level causes a smaller steam bubble. This in turn results in a lower overall pressurizer pressure increase, as a reactor trip would occur faster than when starting at a lower initial pressurizer level. Initializing from 66% span as opposed to 71% span delays the reactor trip and provides a longer increase in pressure before reactor trip, ultimately leading to a higher observed pressurizer pressure.

Pressurizer filling is reported as one of the acceptance criteria for the LOCV event and other anticipated operational occurrences (AOOs) to ensure that the incident does not generate a more serious plant condition without other faults occurring independently. The maximum pressurizer water volume observed during the LOCV event is slightly less than 1100 ft^3. The limit for pressurizer filling criteria is 1519 ft^3. Over 400 ft^3 of margin exists within the pressurizer and a total rise of less than 200 ft^3 is observed from the initiation of the event to the time of maximum volume. The difference between 71% span and 66% span is approximately 76 ft^3 of additional water volume, meaning that over 300 ft^3 of margin would still remain if the maximum initial value was used. Ultimately, pressurizer filling is not significantly challenged in the LOCV event. The chemical and volume control system (CVCS) malfunction event described EPU LAR Attachment 5, Section 2.8.5.5 is the limiting Chapter 15 event with respect to pressurizer filling. It bounds the LOCV event in this regard. The maximum volume of the pressurizer in the CVCS malfunction event is 1512.3 ft^3 which remains below the limit of 1519 ft^3. Note that additional discussion of the CVCS malfunction event as related to initial pressurizer level is contained in the response to RAI SRXB-70.

Similar analysis can be applied to the asymmetric steam generator transient (ASGT) event. The maximum pressurizer water volume observed in the limiting ASGT case is 962.8 ft^3. This case is initialized at 66% span in the pressurizer (63% nominal plus 3% uncertainty). Initializing at 71% span would contribute an extra 76 ft^3 of inventory, however, there would still be significant margin (approximately 480 ft^3) to pressurizer overfill. EPU LAR Attachment 5, Figure 2.8.5.2.5-11 demonstrates that pressurizer overfill is not challenged for the ASGT event.

The control element assembly (CEA) Withdrawal at Power event documents a maximum pressurizer water volume of 1483.4 ft^3 in EPU LAR Attachment 5, Table 2.8.5.4.2-2. The limiting case with respect to pressurizer overfill is the 100% power, maximum reactivity feedback, slow withdrawal of 1 pcm/sec case. This case is run with an initial pressurizer level of 66% span (63% nominal plus 3% uncertainty). Although the maximum possible reactivity insertion limit at 100% power is 500 pcm, the analysis was run with significantly larger reactivity insertion to produce conservative departure from nucleate boiling ratio (DNBR) results. The total reactivity insertion at the time of peak pressurizer volume of 1483.4 ft^3 is 1515 pcm, which is 3 times greater than the CEA withdrawal reactivity insertion limit of 500 pcm that can be achieved at 100% power Analysis of the CEA Withdrawal at Power event documented in EPU LAR Attachment 5, Section 2.8.5.4.2 shows that when the 500 pcm reactivity insertion limit is reached, the pressurizer water volume is approximately 1107 ft^3, which is significantly less than the 1519 ft^3 limit. The transient is run past the reactivity insertion limit conservatively to minimize DNBR margin and force a reactor trip. If the event stopped upon reaching the 500 pcm limit, the system would stabilize at a slightly higher power level and temperature with pressurizer water volume remaining stable near 1107 ft^3.

Applying the CEA withdrawal reactivity insertion limits to all cases analyzed in the CEA withdrawal at power event, the limiting case with respect to pressurizer overfill is determined to be the case at 65% power, maximum reactivity feedback, 1 pcm/sec withdrawal. The peak pressurizer volume observed in this case is 1297 ft^3 with the transient initialized at 66% span in the pressurizer. Initializing at 71% span would contribute an extra 76 ft^3 of inventory, however, there would still be 146 ft^3 of available margin to preclude pressurizer overfill. The CEA withdrawal at power event thus, does not significantly challenge pressurizer overfill.

The initial steam generator (SG) water level is not a key parameter in the LOCV analysis. It is set equal to the nominal SG level of 65% narrow range span (NRS) for all 3 cases performed. This is consistent with the AOR documented in UFSAR, Section 15.2.3, and with Westinghouse standard methodology for the event. Analysis of the LOCV event performed for EPU shows that SG inventory does not increase during the duration of the transient. Therefore, SG margin to overfill (MTO) is not challenged for any of the cases performed for the LOCV event.

The ASGT event, much like the LOCV analysis, is initialized at 65% NRS in the SGs. The limiting case with respect to SG MTO for the ASGT event is the 0% SG tube plugging case which reaches a maximum level of 85.77% NRS in SG #1. Despite the increase in level in SG #1, approximately 2500 ft^3 of MTO exists for the limiting ASGT event. SG overfill, even when including uncertainties or maximum initial level, is not challenged for the ASGT event.

The limiting CEA withdrawal at power case with respect to secondary is the 20% power, 1 pcm/sec withdrawal with maximum reactivity feedback case. The maximum observed SG level is 72.2% NRS at the end of the transient. This is a rise of 7.2% NRS from the initial level of 65% NRS over the duration of the event. Despite the slight rise in SG inventory, approximately 3000 ft^3 of MTO exists for the limiting CEA withdrawal at power event. SG overfill is thus not challenged for this event, even with the maximum initial SG level. The turbine runback is not applicable to St. Lucie Unit 2.

The bounding analysis for the SG MTO is the steam generator tube rupture (SGTR) event. The SGTR event also does not challenge SG overfill since the design of the Combustion Engineering (CE) plants provides significant capacity for secondary inventory. Although not analyzed in the current licensing basis, a SGTR MTO analysis is being addressed in the responses to RAIs SRXB-01 through SRXB-07 to demonstrate that significant margin remains and MTO is not challenged for the St. Lucie Unit 2 EPU. Similarly, the uncontrolled CEA withdrawal at power event and the ASGT event are bounded by the SGTR MTO analysis with respect to challenging MTO.

SRXB-49 (RAI 2.8.5.0-2)

Page 2.8.5.0-13 lists the values of the reactivity feedback coefficients assumed in the analyses of the cooldown events resulting from an increase in heat removal by the secondary. Different values are used: 0.43, 0.0 to 0.43, 0.30 Δk/gm/cc and Figure 2.8.5.0-7 for the moderator density coefficient; Figure 2.8.5.0-6 and -0.45 pcm/°F for the moderator temperature coefficient; and upper curve of Figure 2.8.5.0-5 and Figure 2.8.5.0-8 for the Doppler power coefficient.

Discuss the bases for use of the above different values or functions of the reactivity feedback coefficients in the analyses for each of the cooldown events. This RAI is also applicable to the reactivity coefficients used in the analyses for each of (1) the heatup events on page 2.8.5.0-14, (2) RCS flow reduction events on page 2.8.5.0-17, (3) reactivity transients on page 2.8.5.0-18, and (4) events resulting from an increase or decrease in coolant inventory listed on page 2.8.5.0-20.

Response

Reactivity coefficients are chosen conservatively on an event by event basis depending upon the specific event criteria. The three tables below present the justifications for the moderator density coefficient (MDC), moderator temperature coefficient (MTC) and Doppler power coefficient (DPC) used in each analysis discussed in EPU LAR Attachment 5, Section 2.8.5.0. EPU LAR Attachment 5, Table 2.8.2-2 presents the ranges of MDC, MTC and DPC values used in the EPU Non-LOCA safety analyses. In some cases, however, more conservative reactivity values were chosen to match values used in previous analyses.

Table SRXB-49-1
Moderator Density Coefficient
Justification for EPU Non-LOCA Safety Analyses

Event	MDC Value Justification
Decrease in feedwater temperature	Maximum reactivity feedback is conservatively modeled for this event since it results in a primary system cooldown. As such, the most positive MDC of 0.43 Δk/gm/cc is used.
Increase in feedwater flow rate	Maximum reactivity feedback is conservatively modeled for this event since it results in a primary system cooldown. As such, the most positive MDC of 0.43 Δk/gm/cc is used.
Excessive increase in main steam flow	This event is bounded by other events.
Inadvertent opening of a steam generator (SG) relief or safety valve	This event is bounded by other events.
Pre-trip steamline break (SLB) with failure of the fast bus transfer (FFBT)	Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus maximize the heat flux. A full range of MDC values from 0 to 0.43 Δk/gm/cc are considered in this analysis. The limiting MDC value was determined to be 0.30 Δk/gm/cc through the performed sensitivity study.
Pre-trip steamline break coincident with loss of offsite power (LOOP)	The MDC spectrum scoping performed for the limiting pre-trip SLB with FFBT event identified a limiting MDC value to be 0.30 Δk/gm/cc. This value is also used for the less limiting pre-trip SLB with LOOP event.
Post-trip steamline break	MDC values for the post-trip SLB event are chosen, along with DPC values to model conservative stuck rod coefficients. The values chosen for the MDC are unchanged for EPU and provide maximum core energy transfer to the primary coolant in an effort to maximize potential return to power.
Loss of condenser vacuum – overpressure case	MDC is not a key parameter for this event. A default MDC of 0 is used since minimum moderator reactivity feedback is conservative for a primary system heatup event.
Loss of condenser vacuum – departure from nucleate boiling (DNB) case	MDC is not a key parameter for this event. A default MDC of 0 is used since minimum moderator reactivity feedback is conservative for a primary system heatup event.
Loss of non-emergency AC to the station auxiliaries	This event is bounded by other events.
Loss of normal feedwater flow	This event is bounded by other events.
Feedwater system pipe rupture (FLB) – reactor coolant system (RCS) overpressure case	The FLB event is analyzed as a primary heatup event, and as such, it is conservative to select minimum reactivity feedback. Therefore a 0 MDC value is conservatively chosen.
Feedwater system pipe rupture – main steam (MS) system overpressure case	The FLB event is analyzed as a primary heatup event, and as such, it is conservative to select minimum reactivity feedback. Therefore a 0 MDC value is conservatively chosen.
Asymmetric steam generator transient (ASGT)	Maximum reactivity feedback is conservative for the ASGT event as it maximizes the core power increase. As such, the most positive MDC of 0.43 Δk/gm/cc is chosen.

Table SRXB-49-1 (Continued)
Moderator Density Coefficient
Justification for EPU Non-LOCA Safety Analyses

Event	MDC Value Justification
Partial/complete loss of forced flow	MDC is not a key parameter for this event. A default MDC of 0 is used as minimum reactivity feedback is conservative for a primary system heatup event.
Reactor coolant pump (RCP) seized rotor/shaft break – DNB case	MDC is not a key parameter for this event. A default MDC of 0 is used as minimum reactivity feedback is conservative for a primary system heatup event.
RCP seized rotor/shaft break – overpressure/peak cladding temperature (PCT) case	MDC is not a key parameter for this event. A default MDC of 0 is used as minimum reactivity feedback is conservative for a primary system heatup event.
Uncontrolled control element assembly (CEA) bank withdrawal from subcritical	MDC is not a key parameter for this event. A default MDC of 0 is used.
Uncontrolled CEA bank withdrawal at power	Both minimum and maximum reactivity feedback are considered for this event in an effort to minimize departure from nucleate boiling ratio (DNBR). As such, the full range of 0 to 0.43 Δk/gm/cc is considered for the MDC value.
CEA misoperation (dropped rod)	MDC is not a key parameter for this event. A default MDC of 0 is used.
Startup of an inactive loop at an incorrect temperature	Event precluded by plant Technical Specifications (TS).
Chemical and volume control system (CVCS) malfunction that results in a decrease in the boron concentration in the reactor coolant	Reactivity parameters are not considered in this analysis as no case runs or simulations are performed. This analysis consists of a series of hand calculations used to determine time to criticality and monitoring frequencies.
CEA ejection	MDC is not a key parameter for this event. A default MDC of 0 is used.
Inadvertent emergency core cooling system (ECCS) operation at power	Event precluded by safety injection system design.
CVCS malfunction	Maximum reactivity feedback is conservatively chosen to maximize pressurizer filling during the event. As such, the most positive MDC of 0.43 Δk/gm/cc is used.
Inadvertent RCS depressurization	Minimum MDC reactivity feedback is conservatively chosen to minimize the DNBR. As such a 0 MDC is used in this event consistent with beginning of life (BOL) conditions.
Steam generator tube rupture (SGTR)	The selection of reactivity parameters does not affect the leakage rate and thus has no impact on steam releases and margin to overfill. Therefore, a 0 MDC is used.
Anticipated transients without scram (ATWS)	Precluded by the presence of the diverse scram system (DSS), diverse turbine trip (DTT) and diverse auxiliary feedwater actuation system (DAFAS).

Table SRXB-49-2
Moderator Temperature Coefficient
Justification for EPU Non-LOCA Safety Analyses

Event	MTC Value Justification
Decrease in feedwater temperature	Maximum reactivity feedback is conservatively modeled for this event since it results in a primary system cooldown. As such, the most negative MTC specified in the TS is assumed.
Increase in feedwater flow rate	Maximum reactivity feedback is conservatively modeled for this event since it results in a primary system cooldown. As such, the most negative MTC specified in the TS is assumed.
Excessive increase in main steam flow	This event is bounded by other events.
Inadvertent opening of an SG relief or safety valve	This event is bounded by other events.
Pre-trip steamline break with failure of the fast bus transfer (FFBT)	Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus maximize the heat flux. Therefore, the most negative specified in the TS is chosen.
Pre-trip steamline break coincident with loss of offsite power (LOOP)	Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus maximize the heat flux. Therefore, the most negative MTC specified in the TS is chosen.
Post-trip steamline break	The most negative MTC specified in the TS is chosen as, under a primary system cooldown, a negative MTC will maximize the core energy transfer to the primary coolant and thus maximize the potential for return to power.
Loss of condenser vacuum – overpressure case	Minimum reactivity feedback is conservatively used since the event results in a primary system heatup. EPU LAR Attachment 5, Figure 2.8.5.0-6 indicates that a 0 MTC is applicable to this case at 100% power.
Loss of condenser vacuum – DNB case	Minimum reactivity feedback is conservatively used since the event results in a primary system heatup. EPU LAR Attachment 5, Figure 2.8.5.0-6 indicates that a 0 MTC is applicable to this case at 100% power.
Loss of non-emergency AC to the station auxiliaries	This event is bounded by other events.
Loss of normal feedwater flow	This event is bounded by other events.
Feedwater system pipe rupture – RCS overpressure case	The FLB event is analyzed as a primary heatup event, and as such, it is conservative to select minimum reactivity feedback. Therefore a least negative MTC value of 0 is conservatively chosen.
Feedwater system pipe rupture – MS system overpressure case	The FLB event is analyzed as a primary heatup event, and as such, it is conservative to select minimum reactivity feedback. Therefore a least negative MTC value of 0 is conservatively chosen.
Asymmetric steam generator transient (ASGT)	Maximum reactivity feedback is conservative for the ASGT event as it maximizes the core power increase. As such, the most negative MTC specified in the TS is chosen.

**Table SRXB-49-2 (continued
Moderator Temperature Coefficient
Justification for EPU Non-LOCA Safety Analyses**

Event	MTC Value Justification
Partial/complete loss of forced flow	A least negative MTC of 0 is conservatively chosen for this event as it initially results in a primary system heatup.
RCP seized rotor/shaft break – DNB case	A least negative MTC of 0 is conservatively chosen for this event as it initially results in a primary system heatup.
RCP seized rotor/shaft break – overpressure/PCT case	A least negative MTC of 0 is conservatively chosen for this event as it initially results in a primary system heatup.
Uncontrolled CEA bank withdrawal from subcritical	A least negative (at low power, most positive) MTC of +5 pcm/°F is conservatively chosen for this event as once the initial neutron flux peak is reached, a most positive MTC will result in a higher succeeding rate of power change. The most positive MTC at low power conditions is shown in EPU LAR Attachment 5, Figure 2.8.5.0-6.
Uncontrolled CEA bank withdrawal at power	This event considers both minimum and maximum reactivity feedback in an effort to minimize DNBR. As such, the minimum MTC of 0 and the maximum MTC specified in the TS are considered.
CEA misoperation (dropped rod)	A wide range of MTCs from 0 up to and exceeding the TS limit are conservatively analyzed in an effort to minimize DNBR.
Startup of an inactive loop at an incorrect temperature	Event precluded by plant TS.
CVCS malfunction that results in a decrease in the boron concentration in the reactor coolant	Reactivity parameters are not considered in this analysis as no case runs or simulations are performed. This analysis consists of a series of hand calculations used to determine time to criticality and monitoring frequencies.
CEA ejection	Several MTC values are conservatively used in this analysis. The least negative (or most positive for the hot zero power (HZP) case at BOL conditions) MTC of 0 at hot full power (HFP) or +5 pcm/°F at HZP is conservatively chosen to maximize the power increase in the event. For the HFP and HZP cases at end of life (EOL) conditions, the least negative MTC values are used in an effort to maximize core power increase.
Inadvertent ECCS operation at power	Event precluded by safety injection system design.
CVCS malfunction	Maximum reactivity feedback is conservatively chosen for this event to maximize pressurizer filling. As such, the most negative MTC specified in the TS value is used.
Inadvertent RCS depressurization	Minimum MTC reactivity feedback is chosen for this event The event is insensitive to MTC feedback, and as such, the least negative MTC of 0 is used to maintain consistency with the choice of MDC.
Steam generator tube rupture (SGTR)	The selection of reactivity parameters does not affect the leakage rate and thus has no impact on steam releases and margin to overfill. Therefore, a least negative MTC of 0 is used.
Anticipated transients without scram (ATWS)	Precluded by the presence of the DSS, DTT and DAFAS.

Table SRXB-49-3
Doppler Power Coefficient
Justification for EPU Non-LOCA Safety Analyses

Event	DPC Value Justification*
Decrease in feedwater temperature	Maximum reactivity feedback is conservatively modeled for this event since it results in a primary system cooldown. As such, the least negative DPC curve is used consistent with EOL conditions.
Increase in feedwater flow rate	Maximum reactivity feedback is conservatively modeled for this event since it results in a primary system cooldown. As such, the least negative DPC curve is used consistent with EOL conditions.
Excessive increase in main steam flow	This event is bounded by other events.
Inadvertent opening of an SG relief or safety valve	This event is bounded by other events.
Pre-trip steamline break with failure of the fast bus transfer (FFBT)	Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus maximize the heat flux. Therefore, the least negative DPC curve corresponding to EOL conditions is chosen.
Pre-trip steamline break coincident with loss of offsite power (LOOP)	Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus maximize the heat flux. Therefore, the least negative DPC curve corresponding to EOL conditions is chosen.
Post-trip steamline break	The DPC in the post-trip SLB event is overwritten by a general data table that models a conservative stuck rod Doppler power defect curve chosen to maximize core energy transfer to the primary coolant and thus maximize the possibility for a return to power.
Loss of condenser vacuum – overpressure case	Minimum reactivity feedback is conservatively used as the event results in a primary system heatup. The least negative DPC curve for 100% power is shown in EPU LAR Attachment 5, Figure 2.8.5.0-5 and is used for this event.
Loss of condenser vacuum – DNB case	Minimum reactivity feedback is conservatively used as the event results in a primary system heatup. The least negative DPC curve for 100% power is shown in EPU LAR Attachment 5, Figure 2.8.5.0-5 and is used for this event.
Loss of non-emergency AC to the station auxiliaries	This event is bounded by other events.
Loss of normal feedwater flow	This event is bounded by other events.
Feedwater system pipe rupture – RCS overpressure case	The FLB event is analyzed as a primary heatup event, and as such, it is conservative to select minimum reactivity feedback. Therefore a least negative DPC curve is conservatively chosen.
Feedwater system pipe rupture – MS system overpressure case	The FLB event is analyzed as a primary heatup event, and as such, it is conservative to select minimum reactivity feedback. Therefore a least negative DPC curve is conservatively chosen.
Asymmetric steam generator transient (ASGT)	A least negative DPC curve is conservatively chosen to maximize the core power increase during the ASGT event.

Table SRXB-49-3 (continued)
Doppler Power Coefficient
Justification for EPU Non-LOCA Safety Analyses

Event	DPC Value Justification*
Partial/complete loss of forced flow	A most negative DPC curve is conservatively chosen to maximize the energy transfer to primary coolant during this heatup event.
RCP seized rotor/shaft break – DNB case	A most negative DPC curve is conservatively chosen to maximize the energy transfer to primary coolant during this heatup event.
RCP seized rotor/shaft break – overpressure/PCT case	A most negative DPC curve is conservatively chosen to maximize the energy transfer to primary coolant during this heatup event.
Uncontrolled CEA bank withdrawal from subcritical	A least negative Doppler Power Defect is conservatively chosen to maximize the power peak reached during the initial part of the transient.
Uncontrolled CEA bank withdrawal at power	This event considers both minimum and maximum reactivity feedback in an effort to minimize DNBR. As such, the minimum and maximum DPC curves in Figure 2.8.5.0-5 are considered.
CEA misoperation (dropped rod)	The most negative curve of the Doppler Power Coefficient in Figure 2.8.5.0-5 is used in an effort to minimize DNBR.
Startup of an inactive loop at an incorrect temperature	Event precluded by Plant Technical Specifications.
CVCS malfunction that results in a decrease in the boron concentration in the reactor coolant	Reactivity parameters are not considered in this analysis as no case runs or simulations are performed. This analysis consists of a series of hand calculations used to determine time to criticality and monitoring frequencies.
CEA ejection	A least negative Doppler Power Defect is conservatively chosen to maximize the power peak reached during the initial part of the transient.
Inadvertent ECCS Operation at Power	Event precluded by safety injection system design.
CVCS malfunction	Maximum reactivity feedback is conservatively chosen for this event to maximize pressurizer filling. As such, the most negative DPC curve is used.
Inadvertent RCS Depressurization	Minimum Doppler reactivity feedback is chosen for this event. The event is insensitive to DPC feedback, and as such the least negative DPC curve corresponding to BOL conditions is used to maintain consistency with the choice of MDC.
Steam Generator Tube Rupture (SGTR)	The selection of reactivity parameters does not affect the leakage rate and thus has no impact on steam releases and margin to overfill. Therefore, a least negative DPC curve is used.
Anticipated Transients Without Scram (ATWS)	Precluded by the presence of the DSS, DTT and DAFAS.

* The minimum and maximum DPC curves are shown in EPU LAR Attachment 5, Figure 2.8.5.0-5. For simplicity, they are referred to as minimum (least negative) or maximum (most negative) in the justifications herein.

<u>SRXB-50 (RAI 2.8.5.0-3)</u>

Page 2.8.5.0-18 indicates that ABORTV1 is used in the analysis of the boron dilution event.

Discuss the ABORTV1 code and address acceptability of the code for the analysis.

<u>Response</u>

The ABORTV1 program is an analytical tool used to perform mathematical iterations in the inadvertent boron dilution event. ABORTV1 uses the basic boron dilution equations presented in Section 15.4.6 of the Updated Final Safety Analysis Report (UFSAR). The ABORTV1 program is performed in an iterative manner. That is, the program assumes critical boron concentration values over a range of initial boron concentration values and calculates the corresponding time from alarm to criticality, until the acceptance criterion is exactly satisfied. The end result is a limiting pair of initial to final critical boron concentrations that exactly satisfies the acceptance criterion for operator action for a given mode. This is the same method as one would perform by hand for a typical boron dilution analysis; however, it is automated efficiently through the use of the ABORTV1 program.

<u>SRXB-51 (RAI 2.8.5.0-4)</u>

Table 2.8.5.0-4 lists that the TS and analysis setpoints of the reactor coolant flow – low trip are 95.4% and 88.4% of the thermal design flow, respectively.

Specify the value of the thermal design flow (TDF) in the unit of gpm. Clarify the differences of the TDF, the minimum reactor coolant flow specified in Function 14 of the proposed TS Table 2.2-1, and the lower limit of the reactor coolant flow rate listed in current TS Table 3.2-2. Provide a derivation of the TS trip setpoint from the analysis setpoint for the reactor coolant flow – low trip and address acceptability of the method deriving the setpoint.

<u>Response</u>

Thermal design flow (TDF) for EPU, which is the same as the minimum reactor coolant flow, is 375,000 gpm total or 187,500 gpm per hot leg loop. The current, pre-EPU Technical Specifications (TS) Table 3.2-2 lists a minimum value of 335,000 gpm for the lower limit of the reactor coolant flow and refers to the Core Operating Limits Report (COLR) for the cycle specific minimum reactor coolant flow. The EPU LAR was based on the minimum reactor coolant flow or TDF of 375,000 gpm being in the COLR and deleting the lower limit of the reactor coolant flow in TS Table 3.2-2. However, based on NRC RAIs SRXB-36 and SRXB-37 and FPL's response to these RAIs in FPL letter L-2011-422, dated October 10, 2011, the minimum reactor coolant flow requirement of 375,000 gpm will be moved to TS Limiting Condition for Operation (LCO) 3.2.5 and deleted from the COLR. Also, the EPU LAR proposed change to TS Table 2.2-1 is revised by FPL letter L-2011-422, dated October 10, 2011, such that the minimum reactor coolant flow will refer to TS LCO 3.2.5 and not the COLR.

<u>RCS Low Flow Trip Setpoint</u>

The trip setpoint is defined in the TS Table 2.2-1 as ≥ 95.4% of TDF. The TDF, as stated above, is the same as the minimum reactor coolant flow or 375,000 gpm. The minimum measured flow (MMF) is obtained by applying an uncertainty of 15,000 gpm to the TDF. The MMF is thus equal to 390,000 gpm.

The analysis trip setpoint value is 91.9% of TDF (TDF = 375,000 gpm), which corresponds to 88.4% of MMF (MMF = 390,000 gpm).

In setting the trip setpoint, the analysis value is assumed to be 92% of TDF (slightly conservative with respect to the analysis trip setpoint value of 91.9% of TDF). All the uncertainties related to the measured parameters are applied on top of the analysis setpoint value, including a calibration allowance, to obtain the trip setpoint value to be set at the plant. This setpoint is verified to be greater than 95.4% of TDF, thus meeting the TS requirement.

The measured parameters are:

RCS flow in gpm (F)

Each reactor protective system (RPS) channel signal in volts (V) – The lower limit is 1.0 volt for 0 gpm flow

Cold leg temperature in °F (T)

From the measured flow F and the channel signal V, which is based on the steam generator pressure difference, the signal corresponding to the analysis flow value (92% of 375,000 gpm) is determined as ($|TSP_a|$) using the correlation P as given below as a function of flow ratio f. The correlation P is not impacted by the EPU and thus remains unchanged from the current procedure. Although minor, a density correction factor D is applied to cover the impact of any difference between the measured temperature and the analysis value of 551°F.

$$|TSP_a| = 1.0 + P\,D\,(|V| - 1.0)$$

The total uncertainty, using the root sum square (RMS) method, is calculated to be 0.155 volts, which covers the flow measurement uncertainty (εF) of 15000 gpm, a conservative channel signal uncertainty (εV) of 0.094 volts and a calibration allowance of 0.016 volts.

The uncertainty ε_t' is calculated as follows:

$$(\varepsilon_t')^2 = (\delta|TSP|/\delta F)^2 \bullet \varepsilon_F^2 + (\delta|TSP|/\delta|V|)^2 \bullet \varepsilon_V^2$$

ε_V = 0.094 volts (actual uncertainty is < 0.090 volts)

ε_F = 15,000 gpm

Total uncertainty = ε_t' + 0.016 volts

The final trip setpoint (in volts) thus becomes,

$$|TSP| = 1.155 + P\,D\,(|V| - 1.0)$$

TSP is the Trip Setpoint in volts

V = Channel Signal value corresponding to the measured flow (full flow conditions), in volts

f = (0.92 • TS Flow)/F

P = 1.554 + f (2.54 f – 3.089)

F = Measured Flow, in gpm

D = Density Correction Factor

TS Flow = 375,000 gpm (TDF flow)

This method ensures compliance with the EPU analysis and TS requirements and is thus acceptable for operation at EPU conditions.

SRXB-52 (RAI 2.8.5.1.1-1)

Page 2.8.5.1.1-6 indicates that the minimum SGTP is assumed in the analysis of an increase in feedwater event.

Specify the value of the SGTP level used in the analysis and explain why the value used is conservative, as claim on page 2.8.5.1.1-6 and acceptable.

Response

The level of steam generator tube plugging (SGTP) assumed for the event is 0%. The increase in feedwater event, a cooldown event, is conservatively analyzed to cover the effects of SGTP by assuming that the steam generator heat transfer characteristics are consistent with 0% SGTP and the reactor coolant system flow rate is equivalent to 10% SGTP. This modeling approach is conservative because it maximizes the heat transfer from the primary to secondary side which is more severe for a cooldown event.

SRXB-53 (RAI 2.8.5.1.1-2)

Section 2.8.5.1.1.2.1.3 indicates that the results from the RETRAN code are used to determine if the DNB safety analysis limits for excessive heat removal due to feedwater malfunction are met.

Discuss how the results of the RETRAN code are used in determining if the DNBR limits are met.

Response

For the excessive heat removal events described in EPU LAR Attachment 5, Section 2.8.5.1.1.2.1, Increase in Feedwater Flow, RETRAN is used to determine if the departure from nucleate boiling ratio (DNBR) safety analysis limit is met. Per Reference SRXB-53-1, RETRAN is an NRC approved code that includes capability to calculate DNBR for symmetric events. RETRAN DNBR calculations are conservative for symmetric events when compared to newer DNBR codes such as VIPRE. As described in Section 2.8.5.1.1.2.1, the minimum DNBR calculated by RETRAN for the Feedwater Malfunction event occurred at 140.6 seconds and had a value of 1.96. This value is well above the DNBR analysis limit of 1.42. Since considerable margin exists and there is no core asymmetry in this event, it was confirmed that the conditions at the time of minimum DNBR were within the range for which the conservative RETRAN derived DNBR estimation is valid. Considering the large margin to the limit, the RETRAN DNBR estimation is sufficient to show that the DNBR limit is not violated for this event.

Reference

SRXB-53-1 WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

SRXB-54 (RAI 2.8.5.1.2-1)

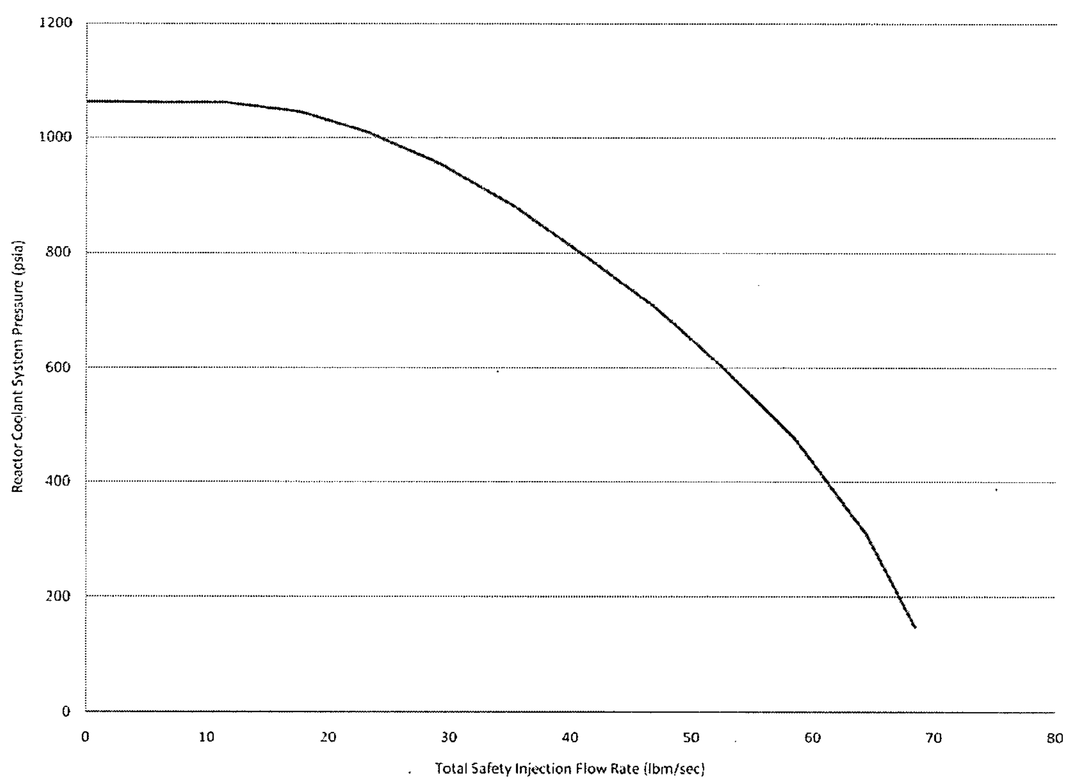
Figure 2.8.5.1.2-18 shows the safety injection (SI) flow curve used in the post-trip steam line break (SLB) analysis for EPU application. This curve appears different from the SI flow curve in UFSAR Figure 15.1.6-3, which is used in the analysis of record (AOR) for the post-trip SLB case. For example, Figure 2.8.5.1.2-18 shows that at the RCS pressure of 200 psia, the SI flow rate is 16.5 lbm/sec versus 70 lbm/sec shown in UFSAR Figure 15.1.6.3.

Explain why different SI flow curves are used for the EPU and AOR analyses, and verify that the SI flow is Figure 2.8.5.1.2-18 represents the flow characteristics of the SI pump for EPU operation.

Response

The safety injection (SI) flow curve given in the Updated Final Safety Analysis Report (UFSAR) Figure 15.1.6.3, is the total SI flow (summation of all four cold legs using one high pressure safety injection (HPSI) pump). The SI flow curve given in the EPU LAR Attachment 5, Figure 2.8.5.1.2-18 is the SI flow for one cold leg using one HPSI pump. Figure SRXB-54-1 below is Figure 2.8.5.1.2-18 converted to total SI flow using one HPSI pump. For example, at 200 psia the minimum SI flow is ~16.5 lbm/sec per cold leg, therefore the total SI flow is 67 lbm/sec (~16.5 lbm/sec * 4). Thus, the SI flow curve used for the EPU post-trip steam line break analysis has a slightly lower total SI flow than the analysis of record SI flow curve. This is conservative as it results in less boron injection after SI actuation.

Figure SRXB-54-1
Total SI Flow Using One HPSI Pump



SRXB-55 (RAI 2.8.5.1.2-2)

Table 2.8.5.1.2-5 includes the sequence of events for the analysis of the limiting post-trip SLB case. This table shows that the criticality occurs at 27 seconds following the manual reactor trip, and the peak heat flux occurs at 31.25 seconds after criticality occurrence. A comparison with the post-trip SLB analysis in AOR, UFSAR Table 15.1.6-1 reveals that for the limiting AOR post-trip SLB case the core criticality occurs at 48.08 seconds following the manual reactor trip and peak heat flux occurs at 257.45 seconds after the core becomes critical.

Explain design differences and assumptions used in the analysis that contributes to a longer delay time to reach the peak heat flux for the AOR case (257.45 seconds) versus that for the EPU case (31.25 seconds) after re-criticality occurs.

Response

A sensitivity study was performed on the post-trip steam line break (SLB) analysis as described in the response to RAI SRXB-57. The study revealed that a vapor lock occurred in the affected steam generator (SG) which dramatically reduced the heat transfer from the primary to the secondary fluid (for additional information see the response to RAI SRXB-57). The sensitivity study revealed that without the vapor lock, the peak heat flux is 6.0% (the analysis of record (AOR) peak heat flux was 18.3%) and the time of peak heat flux occurs at 520.00 seconds which is later than the AOR time of peak heat flux.

Table SRXB-55-1
Analysis of Record - Sensitivity Study*

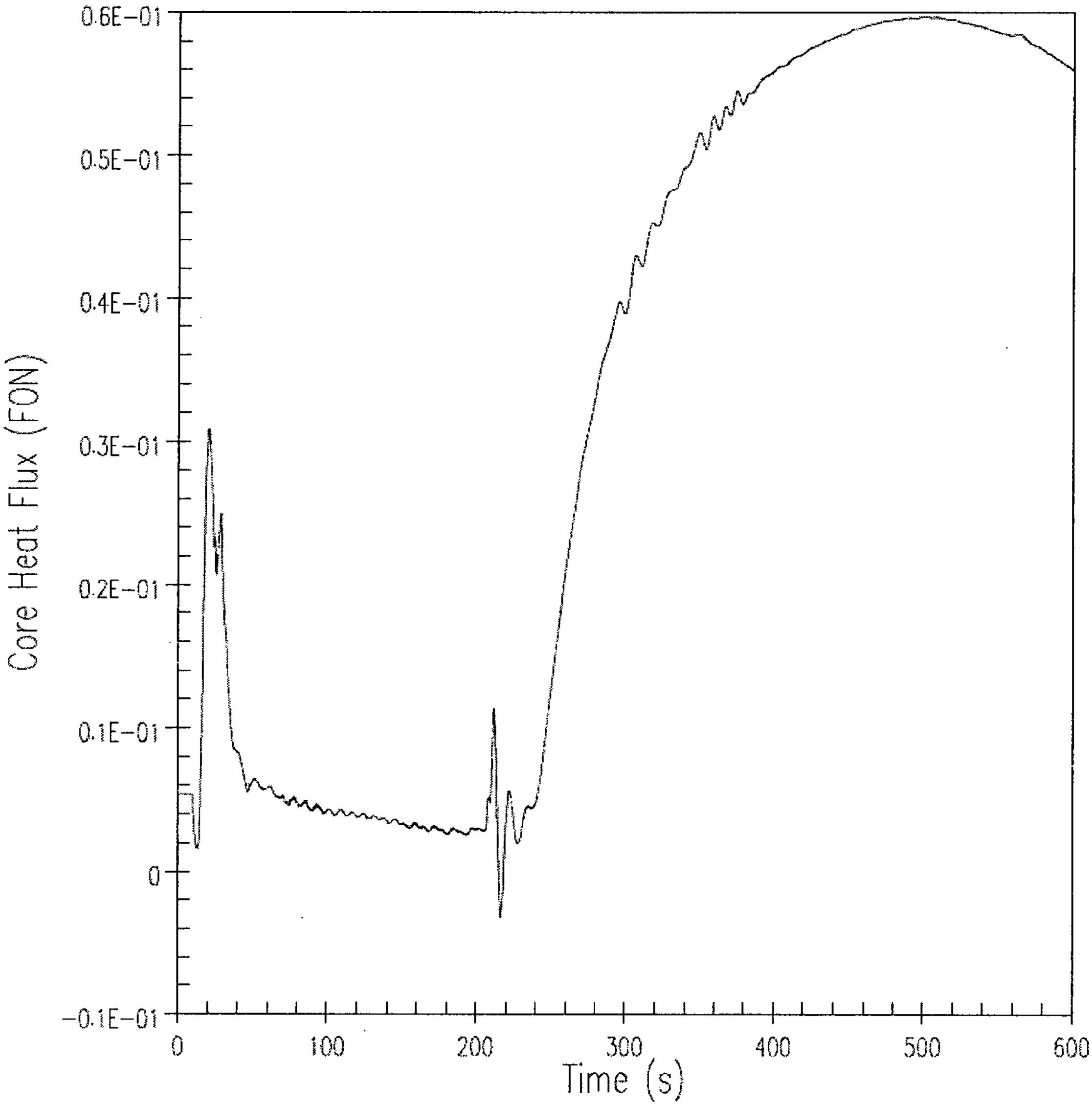
	AOR	Sensitivity Study
Time core criticality attained (sec.)	48.05	182.0
Time of peak heat flux (sec.)	305.50	520.00
* Time values in seconds are not adjusted to reflect different T=0 times, 0.01 seconds for AOR and 10 seconds for sensitivity study.		

The difference between the AOR and sensitivity study results is due to the integral flow restrictor in the exit nozzle of the replacement steam generators. The flow restrictor limits the effective break flow area to 1.910 ft^2, which is significantly smaller than the AOR break flow area of 6.305 ft^2. The reduction in effective break flow area slows the cooldown rate delaying the time to criticality and minimizes the asymmetry between the faulted and non-faulted loops, which is a benefit to SLB events. The sequence of events from the sensitivity study is shown in Table SRXB-55-2 and a plot of Heat Flux vs. Time is presented in Figure SRXB-55-1.

Table SRXB-55-2
Post-Trip Steam Line Break (SLB) Sequence of Events

Event	Time (sec)	Value
SLB (1.910 ft^2 DER) transient initiated	10.0	---
Manual reactor trip	10.0	---
Main steam isolation valve (MSIV) / main feedwater isolation valve (MFIV) closure signal on low steam generator pressure	21.6	487 psia
Safety injection actuation signal (SIAS) on low pressurizer pressure	26.1	1638 psia
Feedwater isolation	26.8	5.15 sec. delay
Steam line isolation (MSIV closure) on loops 1 and 2	28.4	6.75 sec. delay
Core criticality attained	182.0	---
Peak heat flux reached	520.00	6.0%
Minimum departure from nucleate boiling ratio (DNBR) reached	520.00	3.611
Peak linear heat rate reached	520.00	11.41 kW/ft

Figure SRXB-55-1
Core Heat Flux vs. Time



SRXB-56 (RAI 2.8.5.1.2-3)

Figure 2.8.5.1.2-20 shows that at the SLB initiation (10 seconds), the break flow rates are about 7,510 lbm/sec and 3,300 lbm/sec for the unaffected and affected steam generators (SGs), respectively.

Discuss the effective break areas that are assumed for the unaffected and affected SGs at the SLB initiation. If the break flow are assumed for the unaffected SG is different from the cross-sectional area of the integral flow restrictor installed in the SG outlet nozzle, address acceptability of the break flow are assumed in the analysis for the unaffected SG.

Response

The outlet nozzle area of both steam generators (SGs) was modeled to be equal to the area of the integral flow restrictor (1.910 ft^2). The actual break size modeled for the post-trip steam line break (SLB) is equal to a double ended rupture of the steam line (6.305 ft^2). When the break occurs, the steam in the steam line and steam header exits the break experiencing a break size equal to 6.305 ft^2 because it has already passed through the integral flow restrictors. In this analysis, reverse steam flow, any flow along the path from the unaffected SG to the break, is considered to be the break flow from the unaffected SG. Because the flow from the steam line and steam header out the break is considered to be part of the unaffected SG break flow, the initial flow spike for the unaffected SG is significantly larger than the affected SG initial spike. After the steam in the steam line and steam header exits the break, the steam from the unaffected SG flows from the SG experiencing a break flow area equal to 1.910 ft^2. For this reason, after a few seconds the two SG break flow rates are approximately equal (both flows are restricted by the flow restrictors).

SRXB-57 (RAI 2.8.5.1.2-4)

Figure 2.8.5.1.2-23 shows that the cold leg temperature (CLT) decreases rapidly after the SLB initiation. For the affected SG, at about 25 seconds the CLT suddenly increases until 30 seconds, following with a decrease of 8°F. From 38 to 41 seconds, the CLT increases by about 2°F, following with a continued decrease until 93 seconds when the pressurizer is refilled with water. After the pressurizer is refilled, the CLT turns to increase until 150 seconds when the computer runs ends

Explain thermal-hydraulic phenomena for the identified CLT increases during the above period of 0 to 150 seconds in response to applicable system actuations or operator actions.

Response

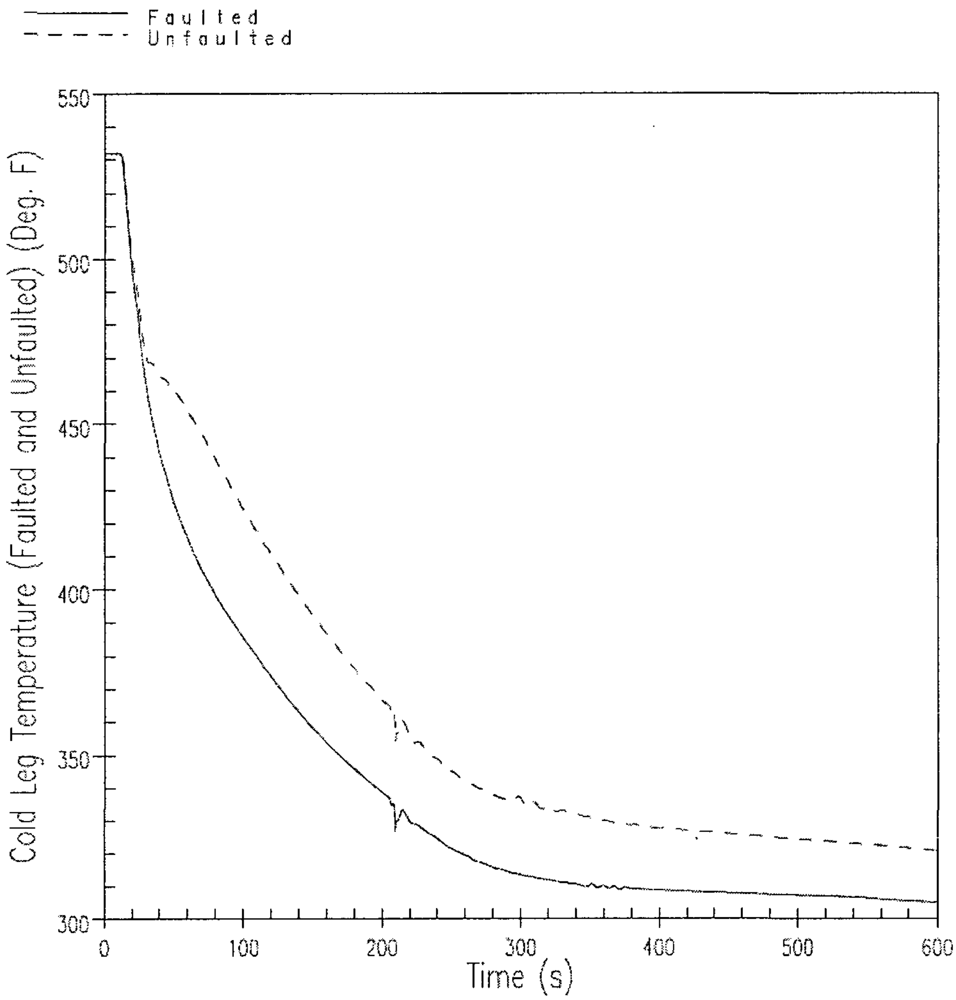
The increase in cold leg temperature from about 25 to 30 seconds and then again from about 38 to 41 seconds in EPU LAR Attachment 5, Figure 2.8.5.1.2-23 is caused by a decrease in heat transfer from the primary to the secondary side. About ten seconds into the steam line break (20 seconds into the figure), the rapid depressurization of the steam generator (SG) causes the liquid (SLB) in the lower downcomer of the SG to flash to steam, forming a vapor bubble in the lower downcomer and lower bundle regions. Due to the high resistance of the evaporator region at this time, the vapor bubble is unable to move from the lower bundle and begins to degrade the heat transfer for that region of the SG U-tubes. The degradation in heat transfer reduces the amount of energy removed from the primary side; retarding the cooldown of the primary side. This resulted in an appearance of the hot leg temperature in the cold leg. Hence, the initial cold leg temperature increase seen at about 25 seconds in Figure 2.8.5.1.2-23.

Along with the temporary loss of heat transfer in that area of the bundle, the depressurization of the SG continues. Eventually, heat transfer from the primary to secondary sides at the lower bundle portion of the SG U-tubes is restored. At which time, cooldown of the reactor coolant system (RCS) recommences and the cold leg temperature begins to decrease again. This is seen at 30 seconds in Figure 2.8.5.1.2-23.

The second increase and decrease 38 to 41 seconds into Figure 2.8.5.1.2-23 is the re-appearance (with one RCS loop time delay) of the first temperature excursion seen between 25 to 30 seconds in the Figure. Between these times, the warmer water is passing through the cold leg once again, but at a cooler condition since heat transfer had been restored. After an additional cycle time, the block of warmer water had been sufficiently mixed and cooled down to see no further increase in the cold leg temperature until 93 seconds.

A sensitivity study was performed to eliminate the vapor lock condition thereby improving the primary to secondary heat transfer and increase the RCS cooldown. The study determined that when there is no vapor lock, the event is extended beyond that noted in the analysis of record (AOR) and the maximum heat flux is 6.0% (the EPU analysis maximum heat flux was 5.6%). The EPU analysis calculated a minimum departure from nucleate boiling ratio (DNBR) of 4.307 with a limit of 1.30 whereas the sensitivity study calculated a minimum DNBR of 3.611. The other major assumptions remained the same between the AOR, EPU and sensitivity study. Those assumptions are that feedwater flow matches steam flow and the feedwater enthalpy is equal to that of the AFW so that the primary system cooldown is maximized. The cold leg temperature vs. time plot from the study is presented in Figure SRXB-57-1.

Figure SRXB-57-1
Post-Trip SLB Cold Leg Temperature vs. Time



SRXB-58 (RAI 2.8.5.1.2-5)

Section 2.8.5.1.2.2.1.2 discusses input parameters and assumptions used in the SLB with a failure of the fast bus transfer (FFBT) case. It lists seven assumptions that are consistent with the first seven assumptions used in the AOR documented in the latest version of the UFSAR, Section 15.1.5.2. However, the last four assumptions (8 through 11) in the AOR are missing. The four assumptions include conservatisms in the analysis in resolving the NRC's concern of thermal-hydraulic modeling of core inlet flow distribution during a 2-pump coastdown applicable to the SLB with the FFBT case.

Address acceptability of deletion of the four assumptions. If the same AOR conservatisms addressing the 2-pump coastdown model remain applicable, add the missing assumptions 8 through 11 to be updated AOR for EPU operation.

Response

Assumptions 8 through 11 listed in Updated Final Safety Analysis (UFSAR) Section 15.1.5.2 are still valid and applicable to the pre-trip steam line break (SLB) with a failure of the fast bus transfer (FFBT) analysis. The assumptions were not listed in EPU LAR Attachment 5, Section 2.8.5.1.2.2.1.2 because they are considered inherent to the approved methodology. The assumptions are listed below for completeness.

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 departure from nucleate boiling ratio (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 (F_r) 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 departure from nucleate boiling (DNB), the most limiting channel's local conditions at the time of minimum departure from nucleate boiling ratio (DNBR) are used to back-calculate F_r corresponding to the DNB specified acceptable fuel design limits (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.

<u>SRXB-59 (RAI 2.8.5.1.2-6)</u>

Figure 2.8.5.1.2-1 includes the results of a sensitivity study showing the peak heat flux as a function of the break sizes of 0.1 to 6.31 ft^2, which represents the cross-sectional area of the steam line. The figure shows that the limiting break, resulting in a highest peak heat flux, is 1.91 ft^2, which is the cross-sectional area of the integral flow restrictor installed in the SG outlet nozzle. The break flow rates and the resulting cooldown effect are limited by the flow area of the integral flow restrictors. However, as shown in the figure, break sizes greater than 1.91 ft^2 are also included for the sensitivity study in determining the limiting break.

Discuss the bases for the use of break sizes greater than 1.91 ft^2 in the sensitivity study.

<u>Response</u>

The maximum area of the steam line is 6.31 ft^2; however, the maximum effective break flow area is limited to 1.91 ft^2 because of the integral flow restrictors. Break sizes greater than 1.91 ft^2 were examined to assure that the most limiting steam generator steam flow was obtained. The driving force for steam flow through the integral flow restrictors is the difference in upstream and downstream pressure. Break sizes larger than 1.91 ft^2 were analyzed to ensure that a lower downstream pressure would not result in a more severe transient.

SRXB-60 (RAI 2.8.5.1.2-7)

Page 2.8.5.1.2-6 indicates that the least negative value of Doppler-only power coefficient (DPC), along with the most negative moderator temperature coefficient (MTC) limit, is used in the analysis of the pre-trip SLB with LOOP case in support of EPU application. For the pre-trip SLB with LOOP case in AOR, page 15.1.10 of the latest version of the UFSAR indicates that a conservative large absolute value of the DPC is used, along with the most-positive MTC limit. Although different values of the DPC (the least negative value vs. a conservative large absolute value) and MTC (the most negative limit vs. the most positive limit) are used in the EPU analysis and AOR, both analyses state that the use of above values of DPC and MTC would maximize the transient core power, resulting in an minimum DNBR.

Explain why a different set of DPC and MTC values (discussed above) used in the EPU analysis and AOR could result in a maximum core power for the pre-trip SLB with LOOP cases.

Response

The pre-trip steam line break (SLB) with loss of offsite power (LOOP) case is very different from a return to power SLB case. Because there is a LOOP at break initiation, the reactor trips on low reactor coolant system flow almost immediately. Therefore, the core does not experience a significant cooldown caused by the excess steaming of the affected steam generator until after the control rods begin to fall into the core. The core, however, experiences a slight heat up prior to the reactor trip.

The analysis of record (AOR) SLB with LOOP analysis showed that the moderator temperature coefficient (MTC) and Doppler power coefficient (DPC) have minimal impact on the calculated minimum departure from nucleate boiling ratio (DNBR). Temperature driven reactivity feedbacks, such as MTC and DPC have minimal impact on the results because the core does not experience a significant coolant temperature change due to the competing effects of the flow coastdown (heat up) due to the LOOP and the steam line break (cooldown). Since the impact of the reactivity feedback is minimal, a large absolute value of DPC along with the most positive MTC was used, treating this as a heatup event.

Similar to the AOR analysis, since the impact of reactivity feedback on this event is minimal, the values used for the EPU analyses were based on maximizing any minor impact of cooldown subsequent to the reactor trip and insertion of rods. Thus, the values used for EPU were least negative DPC and most negative MTC.

Although different values of reactivity coefficients were used for AOR and EPU to maximize effects during a portion of the event progression, the overall impact of these coefficients is not significant to this event.

SRXB-61 (RAI 2.8.5.2.2-1)

Page 2.8.5.2.2.-3 indicates that with respect to long-term cooling (LTC) for the event initiating from a loss of non-emergency AC power to the station auxiliaries (LOAC), the ability of the auxiliary feedwater (AFW) system to remove decay following reactor trip is demonstrated by the analysis in UFSAR Chapter 10. Page 2.8.5.2.2-5 also states LTC analysis for the LOAC is presented in LR Section 2.5.4.5.

Discuss the applicable Chapter 10 and LR Section 2.5.4.5 analyses that are used to demonstrate adequacy of the capability of the AFW system for LTC. Address acceptabilty

of both analyses in terms of the applicable acceptance criteria and the analytical results, methods used, initial conditions and assumptions utilized, equipment relied upon for consequence mitigation and the applicability of the analyses of the LOAC event for LTC. The RAI regarding the LR Section 2.5.4.5 is also applicable to the LTC analyses referred in the analyses of a loss of normal feedwater event (page 2.8.5.2.3-5) and the feedwater line break (page 2.8.5.2.4-4).

Response

The following EPU LR Attachment 5, Section 2.5.4.5 analyses performed in accordance with the Updated Final Safety Analysis Report (UFSAR) Section 10.4.9A are used to assess the adequacy of the auxiliary feedwater (AFW) system for LTC:

- UFSAR Chapter 10 Loss of Normal Feedwater
- UFSAR Chapter 10 Feedwater Line Break

Summaries for these events follow.

UFSAR Chapter 10 Loss of Normal Feedwater

The loss of normal feedwater (LNF) analysis described in EPU LAR Attachment 5, Section 2.5.4.5 is performed consistent with the UFSAR Chapter 10.4.9A. The analysis performed ensures that the AFW system is sized sufficiently for the EPU. According to UFSAR Section 10.4.9A.1, the AFW design bases are to ensure:

1. Sufficient capability exists for removal of decay heat from the reactor core;
2. The ability to reduce reactor coolant system (RCS) temperatures to entry temperatures for activating the shutdown cooling (SDC) system; and
3. Prevent lifting of the pressurizer safety valves (PSVs) when considered in conjunction with the power operated relief valves (PORVs).

Item 1 above is satisfied by assuring that the steam generators (SGs) do not loose heat transfer capability during the event and are able to reduce the RCS temperature. As such, as long as inventory remains in the SGs, the AFW system is proven to provide sufficient capability for decay heat removal. Item 2 above is satisfied by demonstrating that subcooling margin is maintained throughout the entire event and inventory remains in the SGs. Item 3 above is satisfied by assuring the maximum pressurizer pressure remains below the PSV opening setpoint.

In addition to the three requirements listed above, an additional criterion is imposed on the LNF analysis. Maximum pressurizer water volume must remain less than 1519 ft^3, thus ensuring a water solid state is not reached in the pressurizer and the accident does not propagate into a more severe event.

Consistent with the analyses performed in UFSAR Section 10.4.9A, the LNF analysis performed for the EPU includes cases with and without offsite power thus bounding the loss of non-emergency AC power (LOAC) event for long term cooling (LTC). Table SRXB-61-1 illustrates the key analysis parameters for cases with and without offsite power available.

Table SRXB-61-1
Key Analysis Parameters for Loss of Normal Feedwater (LNF)

Parameter		LNF	LNF + Loss of Offsite Power (LOOP)
Core Power		100% + uncertainty (3030 MWt)	100% + uncertainty (3030 MWt)
Loop Flow Rate		Thermal Design Flow (187500 gpm)	Thermal Design Flow (187500 gpm)
Reactor Coolant System (RCS) temperature		High & Low Nominal (578.5 & 563°F)	High & Low Nominal (578.5 & 563°F)
Pressurizer	Initial pressure	Nominal (2250 psia)	Nominal (2250 psia)
	Initial water level	Nominal (63%)	Nominal (63%)
	Charging/letdown	Available	Unavailable
	Heaters	Available	Unavailable
	PORVs	Available	Available
	Sprays	Available	Available
Steam Generator (SG)	Initial water level	Nominal (65%)	Nominal (65%)
	Tube conditions & steam generator tube plugging (SGTP)	Fouled 10%	Fouled 10%
	Atmospheric dump valve (ADV)	Modeled to mimic steam bypass, SG pressure controlled to 900 psia	Conservatively modeled to minimize SG inventory, SG pressure controlled to 900 psia*
Auxiliary Feedwater (AFW)	Pumps	2 motor driven AFW pumps	2 motor driven AFW pumps
	Flowrate **	275 gpm per motor driven AFW pump	275 gpm per motor driven AFW pump
	Delay #	330 sec	330 sec
	Trip setpoint	Nominal – uncertainty (13.0 % NRS)	Nominal – uncertainty (13.0 % NRS)
Loss of offsite power		Not assumed	Assumed on reactor trip
Reactor Trip Setpoint	Pressurizer high pressure	2370 psia	2370 psia
	Low-low SG level	Nominal – uncertainty (14.5 % narrow range scale (NRS))	Nominal – uncertainty (14.5 % NRS)
Reactivity		Beginning of cycle (BOC) w/max. value of β	BOC w/ max. value of β

* During a LOOP, the steam bypass control system (SBCS) is unavailable. ADVs are modeled in the LOOP case to conservatively minimize SG inventory.

** Flowrate listed is for a degraded AFW pump.

\# AFW delay accounts for diesel generator startup and electrical load sequencing. A longer delay puts greater strain on the AFW system and is assumed for both cases.

The LNF analysis performed in accordance with UFSAR Section 10.4.9A shows that more than 10% of the initial SG mass exists in either SG at the end of the transient. Sufficient SG heat transfer capability is proven through the reduction in RCS temperature shown in Figure SRXB-61-1. The pressurizer water volume remains below 1519 ft^3, and as such, the pressurizer does not reach a water solid condition. Pressurizer pressure, despite rising initially, remains below the PSV setpoint and the PSVs do not open during the event. Subcooling margin is maintained throughout the entire event.

The sequence of events for the limiting LNF case (offsite power available) is presented in Table SRXB-61-2. Plots for the LNF case with offsite power available are presented in Figures SRXB-61-1 through SRXB-61-5. Consistent with the current design basis, this analysis has been run conservatively for one hour with no operator action.

Table SRXB-61-2
Loss of Normal Feedwater with Offsite Power Available
Sequence of Events

Time (sec)	Event	Setpoint/Value
0 – 20.0	Steady state period	
20.0	Loss of feedwater to both SGs	
57.8	Reactor trip signal on high pressurizer pressure	2370 psia
57.8	PORV actuates	
58.2	Reactor trip	
60.2	Turbine trip*	
63.7	Low SG level auxiliary feedwater actuation signal (AFAS) setpoint reached	13.0 % (NRS)
393.7	AFW flow reaches the SGs	275 gpm/SG
1162.5	Maximum pressurizer level	1512.2 ft^3
1222.5	Minimum SG inventory	14,444 lbm/SG
3620.0	Operator takes action to commence plant cooldown (1 hour from start of event)	

* Turbine trip is not credited in the transient analysis.

Figure SRXB-61-1
Loss of Normal Feedwater with Offsite Power Available
Hot and Cold Leg Temperature vs. Time

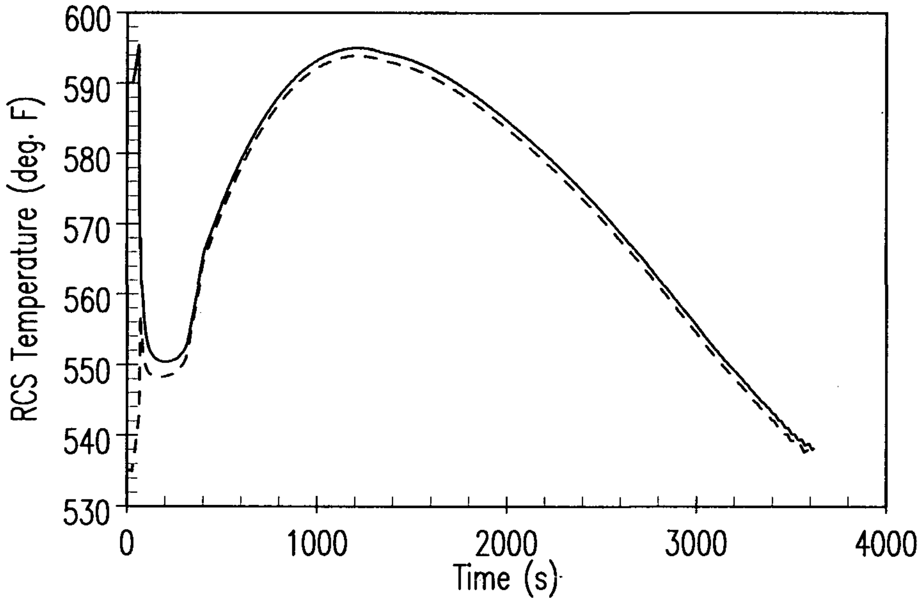


Figure SRXB-61-2
Loss of Normal Feedwater with Offsite Power Available
Steam Generator Mass vs. Time

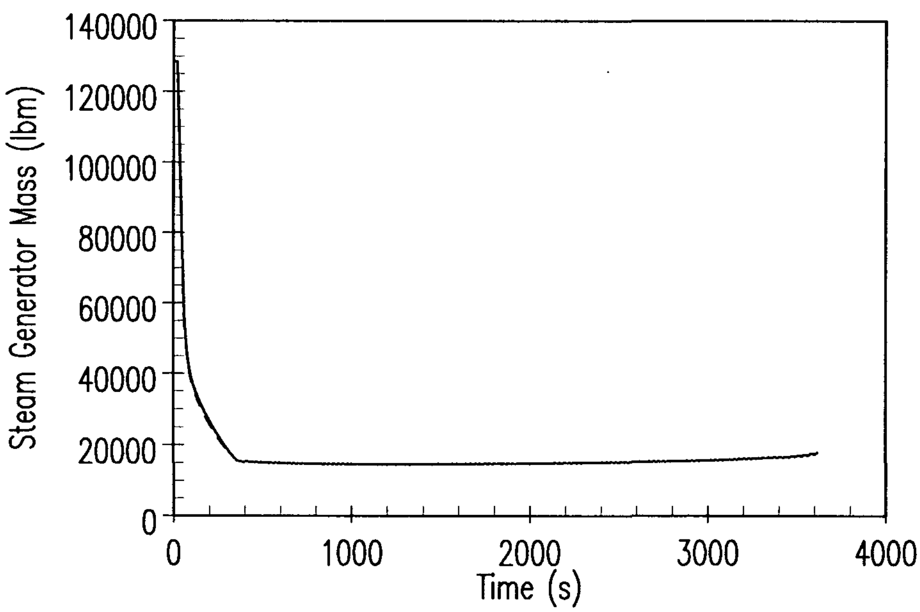


Figure SRXB-61-3
Loss of Normal Feedwater with Offsite Power Available
Pressurizer Pressure vs. Time

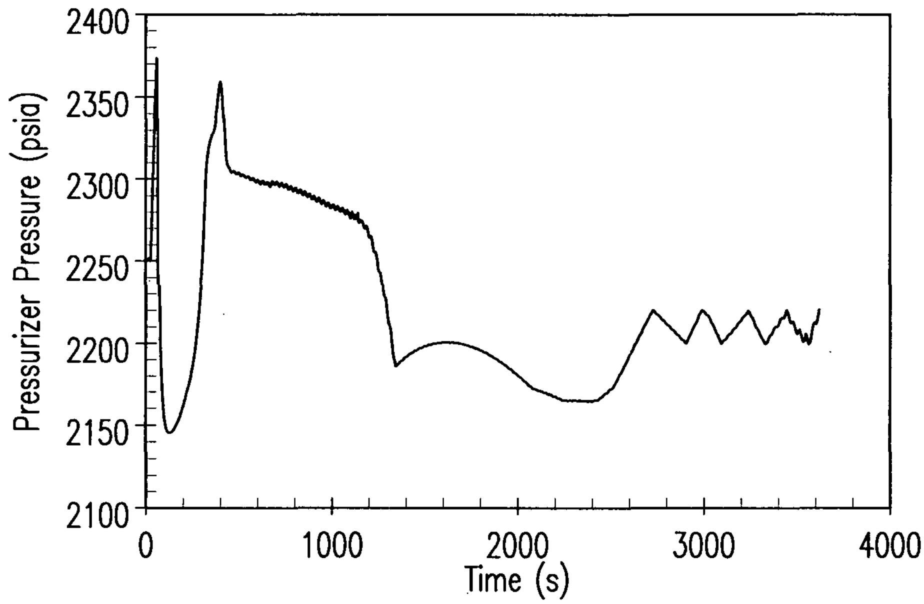


Figure SRXB-61-4
Loss of Normal Feedwater with Offsite Power Available
Pressurizer Water Volume vs. Time

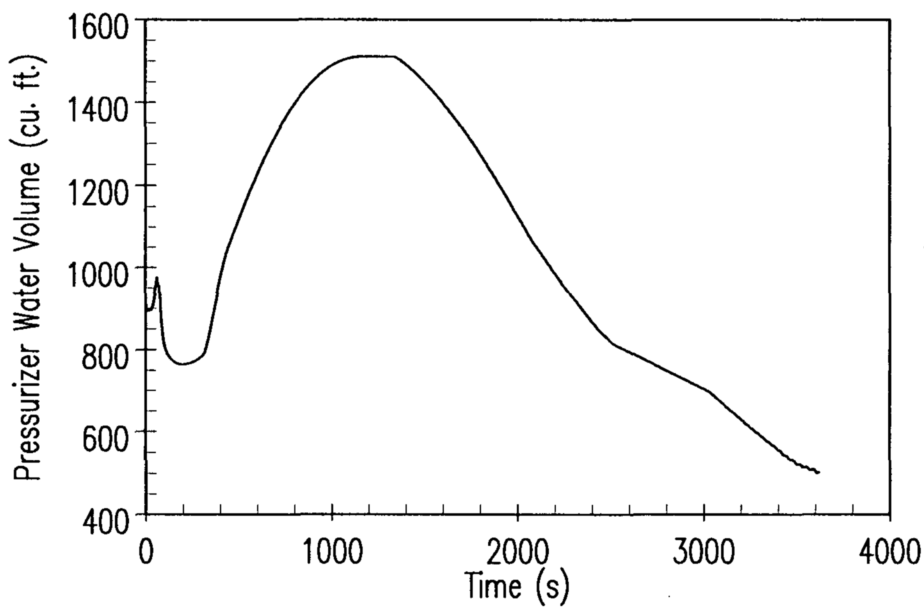
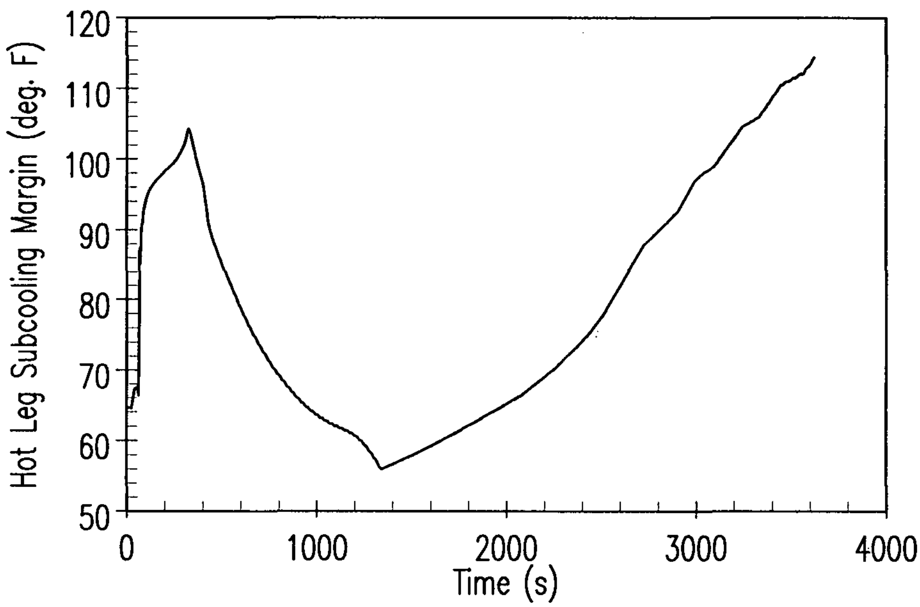


Figure SRXB-61-5
Loss of Normal Feedwater with Offsite Power Available
Hot Leg Subcooling Margin vs. Time



UFSAR Chapter 10 Feedline Break

The feedline break (FLB) analysis described in UFSAR Section 10.4.9A is an auxiliary analysis performed to ensure that the AFW system is sized sufficiently for the EPU. The AFW design bases are to ensure:

1. Sufficient capability exists for removal of decay heat from the reactor core.
2. The ability to reduce RCS temperatures to entry temperatures for activating the SDC system.
3. Prevent the passage of water through the PSVs such that a more serious plant condition will not be generated without other faults occurring independently.

Item 1 above is satisfied by assuring that the SGs do not loose heat transfer capability during the event. As such, as long as inventory remains in the SGs, the AFW system provides sufficient capability for decay heat removal. Item 2 above is satisfied by demonstrating that subcooling margin is maintained throughout the entire event and inventory remains in the SGs. Item 3 is satisfied by ensuring that the PSVs do not pass water by showing that the pressurizer does not become water solid.

Consistent with the analyses performed in UFSAR Section 10.4.9A, the FLB AFW applicability analysis performed for the EPU is a best estimate analysis with some parameters biased in the conservative direction. Thus, nominal initial parameters were considered. Cases with and without offsite power were considered. Table SRXB-61-3 illustrates the key analysis parameters for cases with and without offsite power available.

Table SRXB-61-3
Key Analysis Parameters for Feedline Break (FLB)

Parameter		FLB With AC Power	FLB with LOOP
Core Power		100% + uncertainty (3030 MWt)	100% + uncertainty (3030 MWt)
Loop Flow Rate		Thermal Design Flow (187500 GPM)	Thermal Design Flow (187500 GPM)
Vessel Inlet Temperature		High & Low nominal (551°F & 535°F)	High & Low nominal (551°F & 535°F)
Pressurizer	Initial Pressure	Nominal (2250 psia)	Nominal (2250 psia)
	Initial Water Level	Nominal (63% NRS)	Nominal (63% NRS)
	Charging/Letdown	Available	Unavailable
	Heater	Available	Unavailable
	PORV	Available	Available
	Spray	Available	Available
Steam Generator	Initial Water Level	Nominal (65% span)	Nominal (65% span)
	Tube Conditions & SGTP	Fouled, 10%	Fouled, 10%
	ADV	Unavailable	Unavailable
	SBCS	Available	Unavailable
Auxiliary Feedwater	Pumps	1 motor driven AFW pump	1 motor driven AFW pump
	Flowrate *	275 GPM	275 GPM
	Delay **	420 seconds	420 seconds
	Trip Setpoint	Nominal – harsh environment (4.0% NRS)	Nominal – harsh environment (4.0% NRS)
Loss of Offsite Power		Not assumed	Assumed on reactor trip
Reactor Trip Setpoint	High Pressurizer Pressure	2460 psia	2460 psia
	Low Steam Pressure	546 psia	546 psia
Reactivity		BOC w/ max. value of β	BOC w/ max. value of β

* Flowrate listed is for a degraded AFW pump.

** AFW delay accounts for diesel generator startup and electrical load sequencing. A longer delay puts greater strain on the AFW system and is therefore assumed for both cases.

The FLB analysis performed in accordance with UFSAR Section 10.4.9A shows that there is greater than 7800 lbm in either generator at the end of the transient. The pressurizer water volume remains below 1519 ft^3, and as such, the pressurizer does not reach a water solid condition. Lastly, subcooling margin is maintained in all cases throughout the entire event. Although the pressurizer empties during the high T_{avg} case with AC power, the analysis shows that there is no voiding in the upper head or hot legs and subcooling margin is maintained throughout the entire event. Table SRXB-61-4 provides analysis results.

The sequence of events for the two limiting FLB cases are presented in Tables SRXB-61-5 and SRXB-61-6. Plots of the two limiting cases are presented in Figures SRXB-61-6 through SRXB-61-13. High T_{avg} with AC power available is limiting with respect to minimum unfaulted SG mass and low T_{avg} without AC power available is limiting with respect to maximum pressurizer liquid volume. Both analyses maintain more than 45°F of subcooling during the entire event. Consistent with the current design basis, this analysis has been run for 30 minutes with no operator action.

Table SRXB-61-4
Feedline Break (FLB) Results

Case	AC Power?	T_{avg} (°F)	AFW Flow Rate (GPM)	AFW Delay Time (sec)	Maximum Pressurizer Volume (ft^3)	Minimum Unfaulted SG Mass (lbm)
AC-hi	Yes	578.5	275	420	1429	7864
AC-lo	Yes	563.0	275	420	1422	8500
LOOP-hi	No	578.5	275	420	1336	15940
LOOP-lo	No	563.0	275	420	1444	15941

Table SRXB-61-5
Sequence of Events for Feedline Break
High T_{avg} Case with AC Power

Time (sec)	Event	Setpoint / Value
20.00	Instantaneous complete loss of feedwater to the affected SG; FLB occurs in the main feedwater (MFW) line between the Loop 1 SG and the last check valve	0.375 ft^2
54.73	High pressurizer pressure setpoint reached	2460 psia
55.13	Reactor trip	0.40 second delay
55.87	Control element assembly (CEA) release	0.74 second delay
57.13	Turbine trip	2.0 seconds delay
62.28	Unaffected SG MFW isolation valve (MFIV) closes	---
185.83	Safety injection actuation system (SIAS) generated on low pressurizer pressure	1638 psia
246.15	Loop 2 SG level reaches AFAS setpoint	4.0% NRS
252.50	Minimum pressurizer volume*	0 ft^3
296.01	Loop 2 SG reaches main steam isolation setpoint	487 psia
302.76	Main steam isolation valves (MSIVs) completely closed	---
377.50	Loop 1 SG dryout	< 500 lbm
665.00	Loop 2 SG minimum inventory	7864 lbm
666.15	AFW reaches Loop 2 SG	420 sec
1820.00	Maximum pressurizer volume	1429 ft^3
1820.01	Operator takes actions to commence plant cooldown (1800 sec. after transient initiation)	---

* Although the pressurizer empties during the transient, the analysis shows that there is no voiding in the upper head or hot legs and subcooling margin is maintained.

Table SRXB-61-6
Sequence of Events for Feedline Break
Low T_{avg} Case with LOOP

Time (sec)	Event	Setpoint / Value
20.00	Instantaneous complete loss of feedwater to the affected SG; FLB occurs in the MFW line between the Loop 1 SG and the last check valve	0.375 ft^2
55.24	High pressurizer pressure setpoint reached	2460 psia
55.64	Reactor trip	0.40 second delay
56.38	CEA release	0.74 second delay
57.64	Turbine trip	2.0 seconds delay
62.80	Unaffected SG MFIV closes	---
57.65	Loss of offsite power	---
208.69	Loop 2 SG reaches main steam isolation setpoint	487 psia
215.44	MSIVs completely closed	---
275.00	Minimum pressurizer volume	553 ft^3
290.00	Loop 1 SG dryout	< 500 lbm
904.86	Loop 2 SG level reaches AFAS setpoint	4.0% NRS
1324.86	AFW reaches Loop 2 SG	420 sec
1325.00	Loop 2 SG minimum inventory	15941 lbm
1820.00	Maximum pressurizer volume	1444 ft^3
1820.01	Operator takes actions to commence plant cooldown (1800-sec. after transient initiation)	---

Figure SRXB-61-6
Feedline with AC, High T_{avg}
Steam Generator Inventory vs. Time

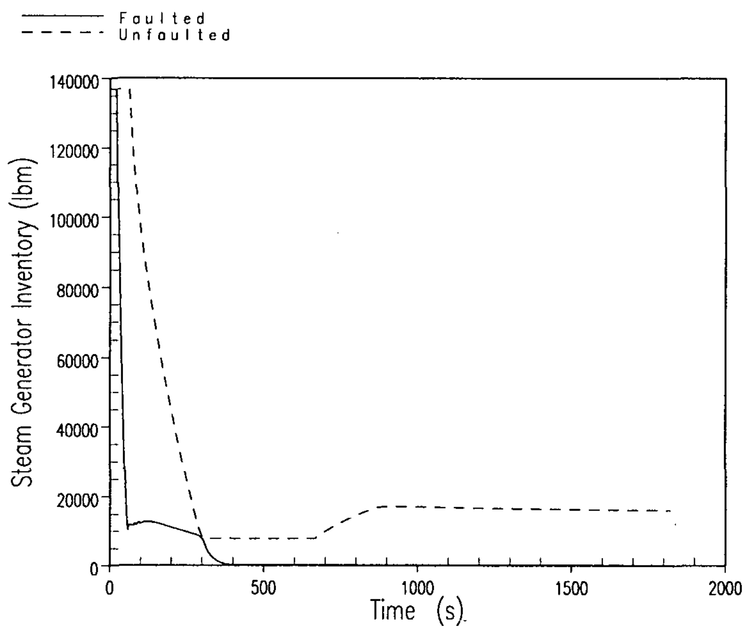


Figure SRXB-61-7
Feedline with AC, High T_{avg}
Pressurizer Pressure vs. Time

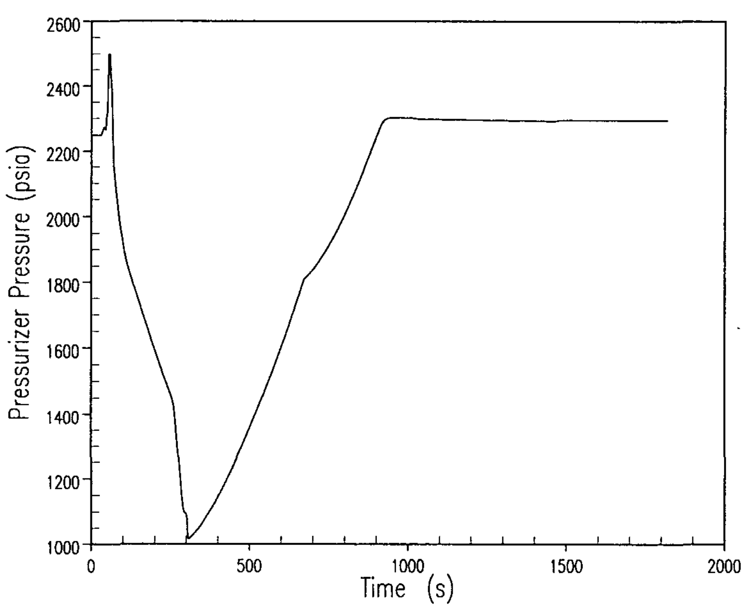


Figure SRXB-61-8
Feedline with AC, High T_{avg}
Pressurizer Volume vs. Time

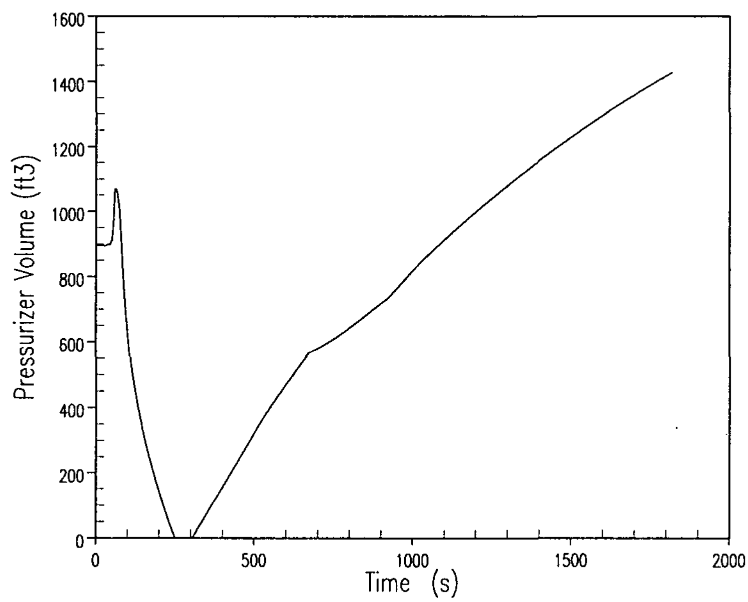


Figure SRXB-61-9
Feedline with AC, High T_{avg}
Core Exit Subcooling Margin vs. Time

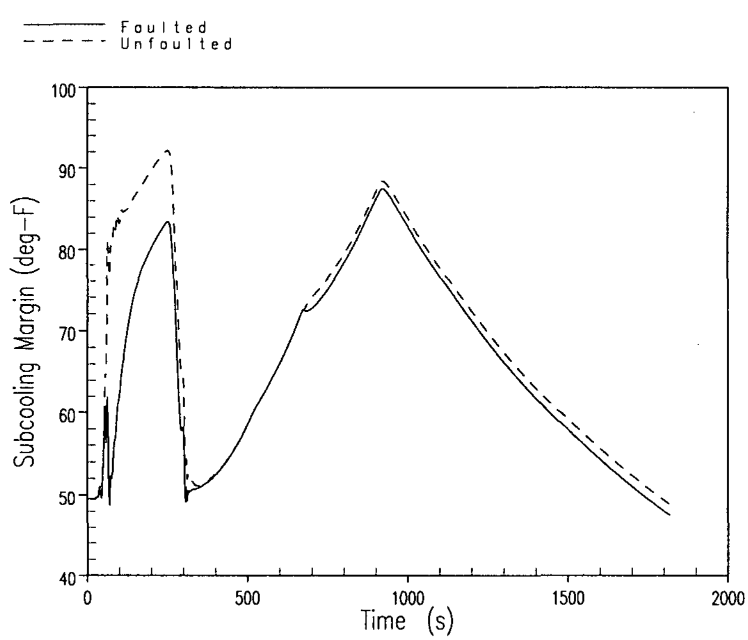


Figure SRXB-61-10
Feedline with Loss of Offsite Power, Low T_{avg}
Steam Generator Inventory vs. Time

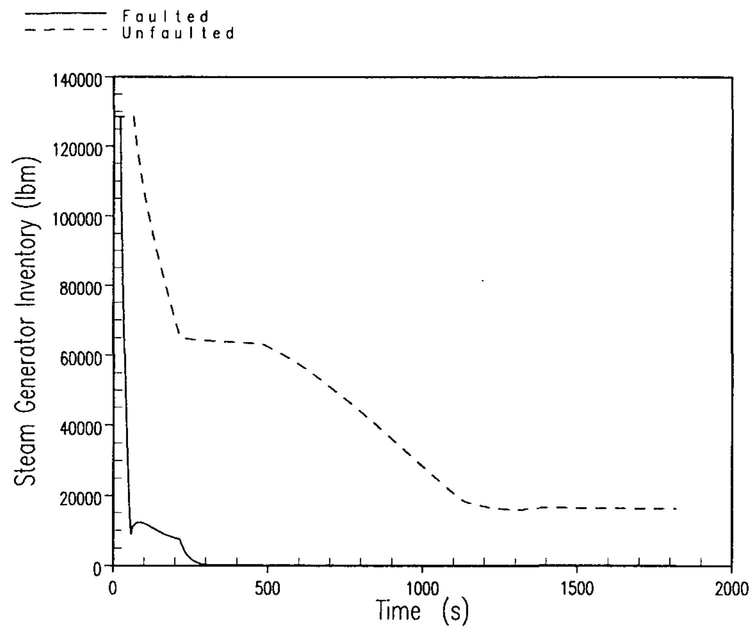


Figure SRXB-61-11
Feedline with Loss of Offsite Power, Low T_{avg}
Pressurizer Pressure vs. Time

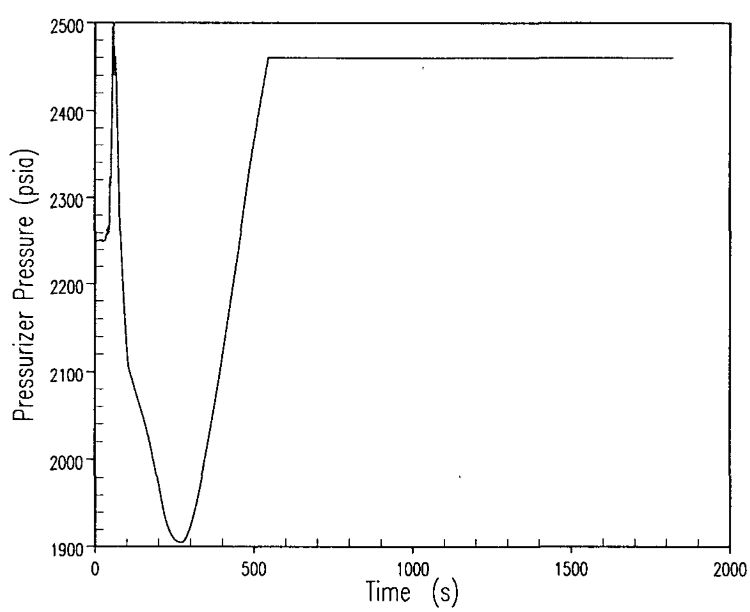


Figure SRXB-61-12
Feedline with Loss of Offsite Power, Low T_{avg}
Pressurizer Volume vs. Time

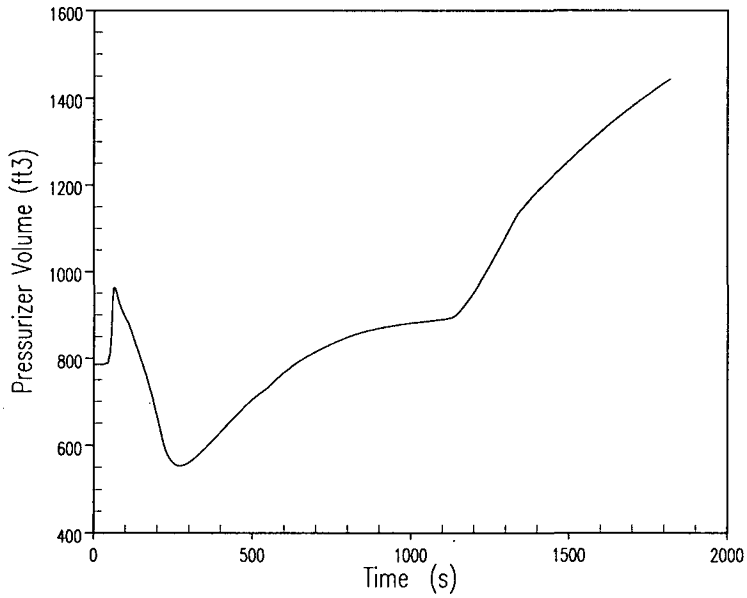
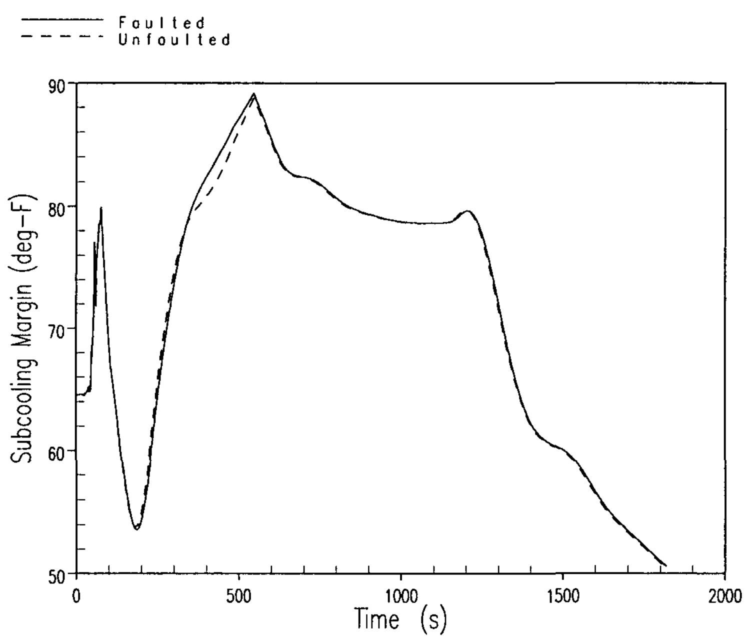


Figure SRXB-61-13
Feedline with Loss of Offsite Power, Low T_{avg}
Core Exit Subcooling Margin vs. Time



SRXB-62 (RAI 2.8.5.2.4-1)

Page 2.8.5.2.4-7 specifies that the break sizes considered in the RCS over-pressurization analyses are 0.21 ft^2 – 0.375 ft^2 and 0.15 ft^2 – 0.20 ft^2 for large and small feedwater line break (FLB), respectively.

Discuss rationale for classification of the FLB into large and small breaks, and discuss the basis for selecting the above ranges of break sizes for the small and large FLBs. Explain why the upper break size is limited to 0.375 ft^2.

Response

The largest break possible is a double ended rupture (DER) of the feedwater pipe. The largest analysis break size for the steam generators (SGs) is assumed to be 0.375 ft^2. This is an acceptable assumption because the analysis of record results show that as the break size increases beyond 0.300 ft^2, the event becomes more benign and therefore, analyzing breaks larger than 0.375 ft^2 would not produce more limiting results. A break size range of 0.10 ft^2 to 0.375 ft^2 is analyzed in the EPU analysis for this event. The EPU analysis also shows that break sizes close to 0.375 ft^2 are less limiting than the limiting case presented in the LAR (0.21 ft^2). The range of break sizes is broken down into two categories, small breaks and large breaks, which are determined based on probability of occurrence. A small break (0.10 ft^2 to ≤ 0.20 ft^2) has a low probability of occurring while a large break (> 0.20ft^2 to 0.375 ft^2) has an even lower probability of occurring. This classification and range of break sizes is consistent with the current design basis in the Updated Final Safety Analysis Report (UFSAR) Section 15.2.8. The reactor coolant system (RCS) pressure acceptance criterion for low probability feedwater line breaks, defined as any break with offsite power available, break sizes ≤ 0.20 ft^2 with failure of the fast bus transfer (FFBT), or break sizes > 0.20 ft^2 without FFBT, is that the pressure must remain less than 110% of the design pressure. The RCS pressure acceptance criterion for very low probability feedwater line 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.

SRXB-63 (RAI 2.8.5.3.2-1)

Page 2.8.5.3.2-5 indicates that "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."

Discuss the technical basis for the above discussed acceptance criteria and address acceptability of the bases used for ensuring "coolable core geometry" during a locked rotor event.

Response

The locked rotor peak cladding temperature (PCT) calculation confirms that the coolable core geometry is ensured during the locked rotor accident, when the hot spot PCT remains below 2375°F and the local oxidation remains below 16%. Both acceptance criteria and the technical bases are discussed in the safety evaluation report enclosed in WCAP-12610-P-A & CENPD-404-P-A Addendum 1-A, "Optimized Zirlo™", July 2006 (Accession No. ML080390451). WCAP-12610-P-A & CENPD-404-P-A Addendum 1-A specifies a maximum cladding oxidation limit of 17%. However, the locked rotor event has historically been analyzed to the more conservative 16% maximum cladding oxidation limit. As such, 16% maximum oxidation level limit was used for this analysis.

SRXB-64 (RAI 2.8.5.4.1-1)

Table 2.8.5.4.1-2 indicates that the peak centerline temperature is limited to 4717°F for the analysis of the uncontrolled CEA withdrawal from a subcritical condition.

Discuss the basis for the above temperature limit.

Response

The melting temperature value is calculated using the equation from Reference SRXB-64-1, Section 2.2.1, for predicting the melting point of UO_2 - Gd_2O_3 solutions. This is an NRC approved document for use in license applications.

[ ]a,c

The starting temperature [ ]a,c represents the melting temperature of UO_2 at zero burnup. A conservative melting temperature [ ]a,c is assumed for this event. The same burnup reduction would apply to the gadolinia doped fuel rods. Therefore, the starting temperature is reduced [ ]a,c and with the maximum gadolinia content of 8 w/o, the equation becomes:

[ ]a,c

References

SRXB-64-1 CENPD-275-P-SUPP 1-P-A (CENPD-275-NP-Supplement 1-NP-A), "C-E Methodology for PWR Core Designs Containing Gadolinia-Urania Burnable Absorbers."

SRXB-65 (RAI 2.8.5.4.2-1)

Page 2.8.5.4.2-5 indicates that ANC documented in WCAP-10965-P-A is used to calculate the peak linear heat rate based on the nuclear power and temperature, and core flow from RETRAN, which is documented in WCAP-14882-P-A. In INSERT 9 of the proposed TS (Attachment 3 to Licensing Report), WCAP-14882-P-A is added to TS 6.9.1.11.b.

Explain why WCAP-10965-P-A is not added to the referred TS.

Response

WCAP-10965-P-A, ANC: A Westinghouse Advanced Nodal Computer Code, Liu Y. S., et al., September 1986, does not appear in the referred Technical Specification because the ANC reference is covered under WCAP-11596-P-A, Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988 ,and this reference appears as Reference 1 in Attachment 3 to the licensing report. Since WCAP-10965-P-A is a referenced portion of WCAP-11596-P-A, the more appropriate ANC reference for clarity is WCAP-11596-P-A.

The following sections reference WCAP-10965-P-A and have been superseded by WCAP-11596-P-A:

- Section 2.8.2, Reference 3,
- Section 2.8.5, Reference 10,
- Section 2.8.5.1.2, Reference 6, and
- Section 2.8.5.4.2, Reference 3.

SRXB-66 (RAI 2.8.5.4.2.1-2)

Tables 2.8.5.4.2-2 and 2.8.5.4.2-3 show the results of an uncontrolled control rod withdrawal at power for the RCS over-pressurization and DNB cases. The results of the main steam system (MSS) over-pressurization cases are missing.

Explain why the results of MSS over-pressurization are not discussed for this event.

Response

The uncontrolled control rod assembly withdrawal at power main steam (MS) system over-pressurization results are bounded by the loss of condenser vacuum (LOCV) event in EPU LAR Attachment 5, Section 2.8.5.2.1, due to the more significant reduction in heat removal capability of the steam generators (SGs). The uncontrolled control rod assembly withdrawal at power event assumes the secondary side operates normally with the turbine still relieving steam flow and pressure prior to the reactor trip. The LOCV event combines a loss of normal feedwater with a turbine trip which results in a total loss of secondary heat sink with the reactor still operating at full power, causing a greater challenge to secondary overpressure. Therefore, the MS system over-pressurization results have not been discussed.

For completeness, the results of the uncontrolled control rod assembly withdrawal at power MS system over-pressurization are presented in Table SRXB-66-1 below. Note that the 100% power, maximum feedback, 2 pcm/sec case yields the most limiting MS system over-pressurization results for all power levels for the uncontrolled control rod assembly withdrawal at power event. Per EPU LAR Attachment 5, Table 2.8.5.2.1-3, the limiting LOCV MS system over-pressurization results are 1093.97 psia.

Table SRXB-66-1
Uncontrolled Control Rod Assembly Withdrawal at Power Event
Limiting Main Steam System Over-Pressurization Results

	Limiting Analysis Value	Analysis Limit	Case
Maximum secondary pressure (psia)	1090.0	1100.0	100% power, maximum feedback, 2 pcm/sec

SRXB-67 (RAI 2.8.5.4.3-1)

Page 2.8.5.4.3-4 states the "peak RCS pressure and peak steam generator pressure conditions are not challenged (non-limiting) during the CEA mis-operation event.

Explain why the RCS and SG over-pressurization cases for the CEA mis-operation event are not the limiting cases.

Response

In the phrase "peak reactor coolant system (RCS) pressure and peak steam generator (SG) pressure conditions are not challenged (non-limiting) during the control element assembly (CEA) mis-operation event," the words "non-limiting" refer to the CEA misoperation event not being the limiting RCS or SG overpressure event. The CEA misoperation event results in an overall depressurization of the system and utilizes the thermal margin/low pressure trip if a lower temperature/pressure equilibrium cannot be reached. A result of this transient response is that CEA misoperation does not challenge overpressure-stress limits and is only analyzed for a departure from nucleate boiling (DNB) response. The loss of condenser vacuum (LOCV) analyses result in a rapid heatup due to the loss of secondary load and will trip on high pressurizer pressure. LOCV is the limiting Condition II RCS and SG overpressure analysis. Therefore, the CEA misoperation event is bounded by the more adverse LOCV event for overpressure described in EPU LAR Attachment 5, Section 2.8.5.2.1 and was not analyzed specifically for the RCS and SG over-pressurization criteria.

SRXB-68 (RAI 2.8.5.4.3-2)

Page 2.8.5.4.3-4 indicates that the transient conditions calculated for a CEA drop event are analyzed with nuclear models to obtain a hot channel factor.

Discuss the nuclear models used for the analysis and address acceptability of the models.

Response

Transient conditions for the control element assembly (CEA) misoperation event, such as the primary system conditions and reactor power, are calculated using the Westinghouse RETRAN-02W computer code (Reference SRXB-68-1). These transient conditions are then analyzed with the Westinghouse VIPRE-W computer code (Reference SRXB-68-2) to determine the hot channel factor at the departure from nucleate boiling (DNB) specified acceptable fuel design limit (SADFL). The VIPRE-W calculated hot channel factor is then compared against the cycle-specific, dropped-rod, hot channel factor, calculated using the ANC computer code, to verify that the transient meets safety analysis limits. ANC is described and approved in Reference SRXB-68-3. These codes have been previously approved and used for this application.

References:

SRXB-68-1 WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999.

SRXB-68-2 WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999.

SRXB-68-3 WCAP-11596-P-A (Proprietary), Qualification of the Phoenix-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988.

SRXB-69 (RAI 2.8.5.4.5)

For each of the boron dilution cases, please provide a sequence of events table, identifying the alarm or trip that is actuated, indicating the time at which it occurs, and showing that there is adequate time available, for operator actions, beginning at the time of the alarm or trip.

Response

The sequence of events for each of the boron dilution event cases is given below.

Event Description	Time Event Begins (minutes)	Alarm or Trip that Occurs	Time Alarm or Trip Occurs (minutes)	Time from Alarm Until Loss of Shutdown Margin (SDM) (minutes)
Mode 1	0.0	High Pressurizer Pressure (HPP)	5.0*	89.1
Mode 2	0.0	High Rate of Change of Power	0.0**	100.3
Mode 3 (Results for the limiting case, 3 charging pumps operating)	0.0	Boron Dilution Alarm (BDA)	51.69	18.74
Mode 4 (1 reactor coolant pump operating) (Results for the limiting case, 3 charging pumps operating)	0.0	BDA	51.02	18.92
Mode 4 on shutdown cooling (Results for the limiting case, 3 charging pumps operating)	0.0	BDA	> 30***	15.25
Mode 5 (water level to hot leg centerline) (Results for the limiting case, 3 charging pumps operating)	0.0	BDA	> 30***	15.25
Mode 6 ARO (water level to hot leg centerline) (Results for the limiting case, 3 charging pumps operating)	0.0	BDA	> 30***	30.25

* Actual value ~2 minutes, however the time was rounded up to 5.0 minutes for added conservatism in the available operator action time calculation.

** If a boron dilution event were to occur during Mode 2, the alarm would sound almost instantaneously. Thus, the time the alarm sounds is set to 0.0 minutes.

*** Initial boron concentrations in combination with critical boron concentration, as specified in LR Tables 2.8.5.4.5-3 through 5, gives the operators exactly enough time to mitigate a boron dilution event (15.25 minutes for Modes 4 and 5 and 30.25 minutes for Modes 6). The time at which the alarm occurs is different for each case depending on the initial boron concentration. The time to alarm is greater if less than 3 charging pumps are in operation.

SRXB-70 (RAI 2.8.5.5-1)

Assumption 5 on page 2.8.5.5-4 states that to maximize pressurizer mixture volume the initial pressurizer level is conservatively set to 60 percent, based on the nominal level minus the level uncertainty.

Specify the values of the nominal pressurizer water level and associated measurement uncertainty. Explain why the maximum pressurizer level, based on the upper range of the pressurizer level in TS 3/4.4.3 plus measurement uncertainty, would not result in a maximum pressurizer mixing volume during the RCS inventory increase events.

Response

Nominal pressurizer water level is 63% with a +/- 3% uncertainty (i.e., 60% to 66%). The nominal level minus uncertainty is used to delay the time to the pressurizer high level alarm (PHLA) setpoint, and thus maximize the charging flow injected prior to operator actions. The operators are alerted to a reactor coolant system (RCS) inventory increase event by either a high pressurizer pressure trip (HPPT) or by the "safety grade" PHLA. Twenty (20) minutes after either HPPT or the PHLA, it is assumed that the operators mitigate the event by reducing/stopping charging flow and/or restoring letdown flow. If the upper range of the pressurizer level Technical Specification (68%) with added uncertainty was used, the PHLA would actuate at event initiation and the same operator action (and associated action time) would occur, resulting in no change in maximum pressurizer level. An early PHLA would change the timing of the PHLA, but will not result in a worse maximum pressurizer level since, in either case, the operator action would occur within 20 minutes from the actuation of the PHLA given the same charging flow injection. Analysis of the RCS inventory increase event performed using nominal pressurizer level minus uncertainty is acceptable and conservative.

SRXB-71 (RAI 2.8.5.5-2)

Assumption 12 on page 2.8.5.5-4 states that operator action to mitigate the CVCS malfunction event by reducing charging flow and/or restoring letdown flow is assumed 20 minutes after either a pressurizer pressure trip, or the high level alarm (PLHA) occurs.

Discuss the basis for use of the operator action time of 20 minutes, and describe a plant specific program that is used to assure that operators can complete the action credited in the analysis within the required action times.

Response

The response is being provided in a separate submittal.

SRXB-72 (RAI 2.8.5.6.1-1)

Page 2.8.5.6.1-4 indicates that to minimize the DNBRs during an accidental depressurization event the analysis assumes a conservative MTC of 0 pcm/°F at hot full power conditions.

Explain why use of the MTC of 0 pcm/°F is conservative, resulting in a minimum DNBR.

Response

The accidental depressurization is a very quick transient which is analyzed for minimum departure from nucleate boiling ratio (DNBR). The core nuclear parameters are chosen to minimize the resulting DNBR. To calculate a limiting minimum DNBR, minimum reactivity feedback is used and a least negative moderator temperature coefficient (MTC) is typically chosen. The least negative MTC is the typical value modeled because departure from nucleate boiling (DNB) events usually result in a temperature heatup. This depressurization transient results in a slight temperature decrease (about 1°F). Since the event is a rapid depressurization and pressure is the driving force for the transient, utilizing a negative MTC as opposed to a zero MTC will have a negligible adverse impact on the minimum DNB results. The depressurization analysis results show a 17.9% margin to the minimum DNB limit. When taking into account the effect of a 1°F cooldown, the margin to DNB decreases to 17.7%, which is why the MTC is said to have a negligible impact on results for a depressurization analysis.

SRXB-73 (RAI 2.8.5.6.1-2)

The titles for Figure 2.8.5.6.1-1 and Figure 2.8.5.6.1-2 are nuclear power and pressurizer pressure vs. time, respectively, while the respective plots show the pressurizer pressure and vessel average temperature vs. time.

Clarify the inconsistencies and provide correct figures for review.

Response

In EPU LAR Attachment 5, Figure 2.8.5.6.1-1 was inadvertently omitted from the document, but the correct title of Nuclear Power vs. Time was maintained. Figure 2.8.5.6.1-2 Pressurizer Pressure vs. Time was replaced with Figure 2.8.5.6.1-3 Vessel Average Temperature vs. Time. However, the correct title of Pressurizer Pressure vs. Time was maintained. EPU LAR Figure 2.8.5.6.1-3 Vessel Average Temperature vs. Time was repeated as Figure 2.8.5.6.1-3, aligning the remaining Figures 2.8.5.6.1-3 through 2.8.5.6.1-5 with the correct title. Figure 2.8.5.6.1-1 and Figure 2.8.5.6.1-2 are provided below. Figures 2.8.5.6.1-3 through 2.8.5.6.1-5 of Section 2.8.5.6.1 remain as presented and are correct.

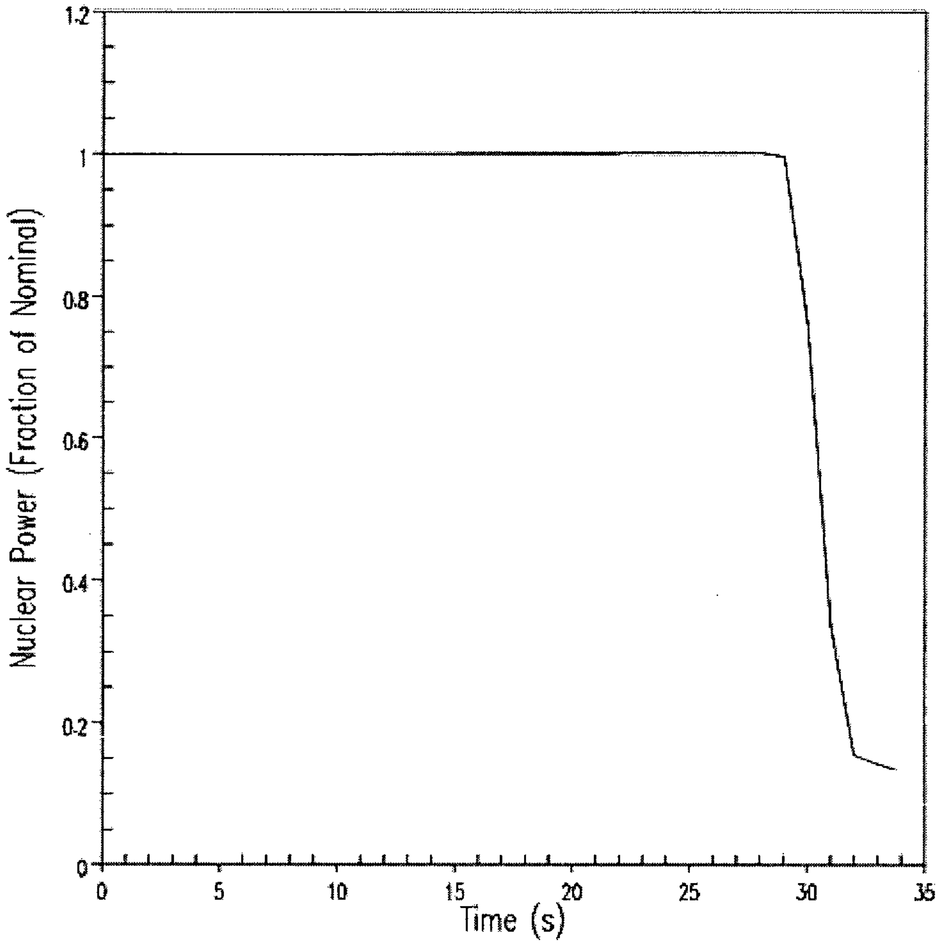


Figure 2.8.5.6.1-1
RCS Depressurization
Nuclear Power vs. Time

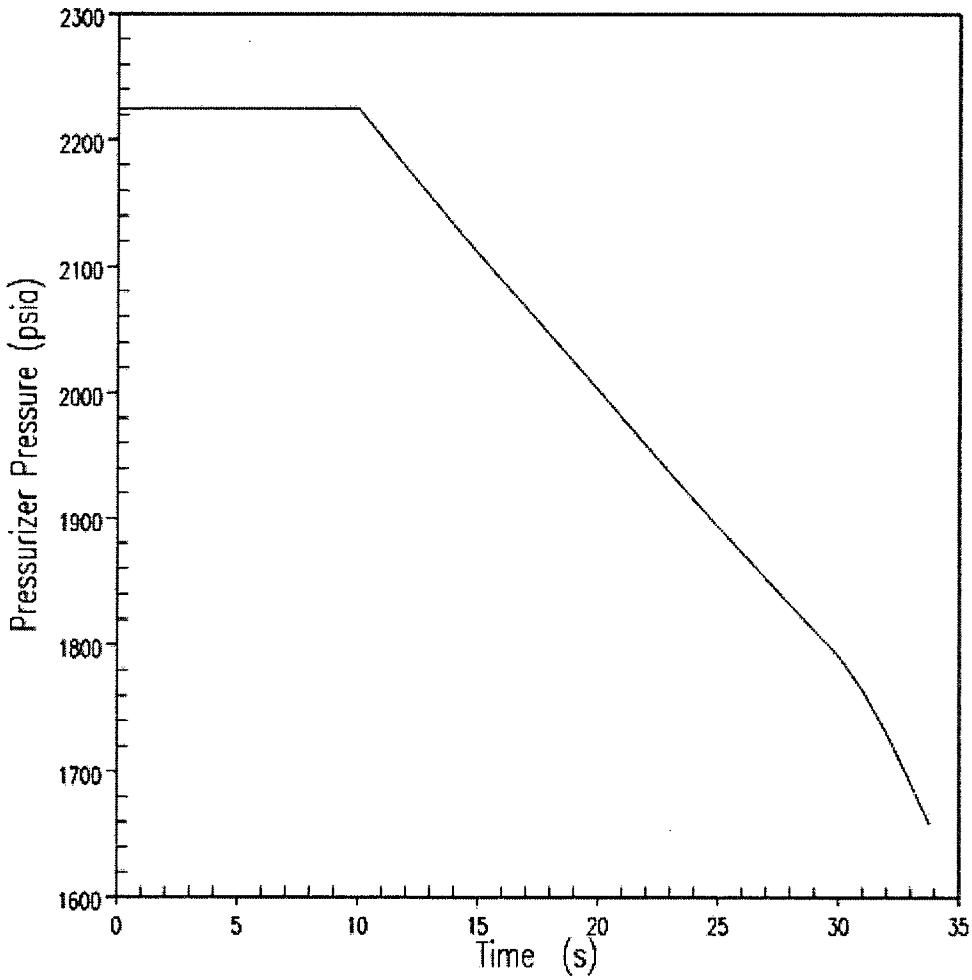


Figure 2.8.5.6.1-2
RCS Depressurization
Pressurizer Pressure vs. Time

SRXB-74 (RAI 2.8.5.7-1)

Discuss systems, components, and procedures that are used to provide long-term shutdown capability following the anticipated transient without scram (ATWS).

Response

The limiting anticipated transient without scram (ATWS) events are the loss of load (LOL) and the loss of main feedwater (LOFW). For the St. Lucie Unit 2 class of plants, analyses demonstrated that a diverse scram system (DSS) with a 2450 psia trip setpoint and a 2-second response time would maintain the peak reactor coolant system (RCS) pressure to less than 3200 psig for the limiting anticipated operational occurrences (AOOs). The sequences of events for the LOL and LOFW ATWS analyses credit the following systems and components for short term mitigation of the ATWS pressurization up until and shortly after reactor trip on the high pressurizer pressure DSS setpoint of 2450 psia.

- The presence and activation of the DSS, diverse turbine trip (DTT) and diverse auxiliary feedwater actuation system (DAFAS);
- Steam dump and bypass control system;
- Auxiliary feedwater (AFW) system;
- Pressurizer spray activation;
- Main steam safety valves (MSSVs);
- Power operated relief valves (PORVs); and
- Pressurizer safety valves (PSVs).

The analyses performed to demonstrate DSS applicability are only run until the RCS pressurization turns around. As pressure falls due to reactor trip on DSS and minimal contributions from moderator temperature coefficient (MTC) effects, the PSVs and PORVs both close and the pressurizer sprays deactivate at the respective pressurizer pressure setpoints. Following the reactor trip on the high pressure DSS setpoint of 2450 psia, the post-trip event progression is similar to one that would occur in any of the other overpressurization events.

As described in EPU LAR Attachment 5, Section 2.8.5.7.2.2, the DSS, DTT and DAFAS reduce the likelihood of a failure to shutdown the reactor following anticipated transients, and mitigate the consequences of anticipated transients followed by a failure of the reactor protective system (RPS). Following actuation of these systems to shutdown the reactor, cooldown and long-term cooling are maintained by normal system operation. Thus, the systems and components used following reactor trip on DSS would be no different than those used in normal post-trip procedures.

The procedure used to ensure long term shutdown capability following a reactor trip is St. Lucie Unit 2 Emergency Operating Procedure 2-EOP-01 (EOP-1), Standard Post Trip Actions.

Main and auxiliary feedwater are used to feed the steam generators. Steam bypass control system dumping to the condensers (if available) or atmospheric dump valves to atmosphere are used to reduce RCS temperature and pressure. When shutdown cooling system (SDC) entry temperature and pressure conditions are achieved, the SDC is used to maintain long-term cooling.

EOP-1, Standard Post Trip Actions, provides the actions to ensure the reactor is shutdown, and establishing a stable, safe plant conditions until transition to EOP-2, Reactor Trip Recovery. EOP-2 provides the actions to establish the plant in Mode 3 Hot Standby and to minimize any releases to the environment, until transition to the General Operating Procedure (GOP) Reactor Plant Cooldown – Hot Standby to Cold Shutdown. This GOP provides the instructions for cooldown and depressurization of the reactor coolant system and transitions to the Normal Operating Procedure (NOP) for shutdown cooling.

SRXB-75 (RAI 2.8.5.7-2)

ATWS, or failure of control rod insertion, can be attributed to common mode failures such as (1) failure of the sensors that feed the reactor trip system, (2) failure of the reactor trip breakers to open and (3) a mechanical failure which prevents control insertion. The following questions pertain to the mechanical common mode failure.

Assess the credibility of an ATWS caused by mechanical common mode failure, and discuss the applicability of ATWS analyses in cases in which a mechanical common mode failure is assumed.

Response

Per Standard Review Plan (SRP) 15.8, an anticipated transient without scram (ATWS) is an anticipated operational occurrence (AOO) as defined in Appendix A to 10 CFR 50, followed by the failure of the reactor trip portion of the protection system. Since protection systems must satisfy the single-failure criterion, multiple failures or a common mode failure must cause the assumed failure of the reactor trip. The probability of an AOO, in coincidence with multiple failures or a common mode failure, is much lower than the probability of any of the other events that are evaluated under SRP Chapter 15. Therefore, an ATWS event cannot be classified as either an AOO or a design-basis accident.

Under the requirements of 10 CFR 50.62 (ATWS Rule), St. Lucie Unit 2 has a diverse scram system (DSS) that assures diversity within the Reactor Protection System (RPS) from the sensor output to the interruption of power to the control rods. St. Lucie Unit 2 also complies with the requirements for a diverse turbine trip (DTT) and a diverse auxiliary feedwater actuation system (DAFAS).

Thus, St. Lucie Unit 2 complies with the failure modes consistent with the ATWS rule and has installed systems and equipment, which provide reasonable assurance that unacceptable plant conditions do not occur in the event of an ATWS.

The evaluation transmitted via FPL letter L-2011-273 R. L. Anderson (FPL) to US Nuclear Regulatory Commission, "Information Regarding Anticipated Transient Without Scram (ATWS) Provided In Support of the Extended Power Uprate License Amendment Request," dated July 22, 2011 (Accession No. ML11207A455) discusses the applicability of the DSS setpoints for EPU and demonstrates that, at EPU conditions with the DSS installed, there is adequate protection to prevent RCS pressurization to 3200 psig, which is the ASME Service Level C limit applicable to ATWS events.

<u>SRXB-76 (RAI 2.8.7.1-1)</u>

Table 2.8.7.1-1 indicates in the last column that the maximum allowable reactor vessel pressurization to avoid core uncover is 3 psig during a loss of RHR at mid-loop conditions.

Provide the basis for use of the reactor vessel pressurization limit of 3 psig.

<u>Response</u>

The reactor coolant system (RCS) hot legs must remain adequately vented during mid-loop operations to avoid pressurizing the reactor vessel upper plenum during core boiling if the cold leg is open to atmosphere. Under these conditions, pressurizing the vessel to greater than 3.0 psig could result in loss of coolant inventory and subsequent core uncovery. The 3.0 psig value used in the current evaluation is based on a calculated value from the historical supporting Combustion Engineering (CE) Owners Group (CEOG) evaluation, performed on a generic basis. The generic analysis is applicable to CE plants and a specific value is provided for St. Lucie Unit 2. The value represents the pressure drop necessary to depress the water level to the top of the active core to vent out a postulated vent path of an open RCS. For St. Lucie Unit 2 plant configuration, this represents the elevation head between the top of the active core and the top of the cold leg.

<u>SRXB-77 (RAI 2.8.7.2-1)</u>

Table 2.8.7.2-2 includes the results of the natural circulation cooldown (NCC) analysis using the CENTS based on cooldown rates of 30°F/hr and 50°F/hr.

Provide the following information in support of the results in Table 2.8.7.2-2

1. **a discussion addressing acceptability of use of CENTS for the NCC analysis, and justifying adequacy of any changes to the NRC-approved version of CENTS**
2. **a discussion to show acceptability of the assumptions used and worst single failure considered in the NCC analysis**
3. **a discussion of the results of the NCC analysis to show that the predicted thermal-hydraulic response is within the range approved by the NRC for use of the CENTS code, and there is no unexplainable thermal-hydraulic phenomena for parameters**
4. **justification for use of the decay heat rates based on ANI/ANS-5.1-1979**
5. **a derivation of the required CST water volume for the NCC analysis to show that the required CST water volume is within the TS limits**
6. **a discussion of compliance with the branch positions F and G in BTP RSB 5-4 (SRP, Revision 3).**

<u>Response</u>

1. The CENTS code is not used in the current licensing basis (CLB) natural circulation cooldown (NCC) analysis, but is an approved code that is acceptable for referencing in licensing applications for Combustion Engineering (CE) design pressurized water reactors (PWRs). There are no changes to the CENTS code as used in the St. Lucie Unit 2 analysis. The only limitation of the CENTS code as applied in this analysis is related to the bounds of the fluid property tables. The temperature and pressure conditions considered in the NCC analysis are within the bounds of the CENTS code; therefore it is appropriate to use CENTS for the NCC analysis.

2. The plant conditions and assumptions used in the NCC analysis are listed below.

   - Plant power is initially at 100.5% of rated power to account for indicated power uncertainty.
   - 1979 ANS 5.1 Standard Decay Heat Curve including long term actinides is used.
   - One charging pump is operating following the plant trip.
   - Letdown is disabled.
   - Main feedwater is disabled.
   - Main steam safety valves (MSSVs) provide the initial heat removal path.
   - Safety injection system (SIS) is not used.
   - RCS heat losses to containment are set to zero.
   - Reactor vessel upper head heat losses to containment are set to zero.
   - Main steam isolation valves (MSIVs) are closed.
   - The auxiliary feedwater (AFW) flow is set to maintain steam generator level to match boiloff during the cooldown.

   As required, charging is controlled to maintain pressurizer level within acceptable range.

   The most limiting single failure for the NCC analysis is a loss of one direct current (DC) emergency power train. A loss of one DC emergency train would prevent alternating current (AC) from one emergency diesel generator (EDG) from being transferred to the onsite electrical system. The single failure disables one train of components associated with the atmospheric dump valves (ADVs), Chemical and Volume Control System (CVCS), AFW system, and shutdown cooling (SDC) system. Only two of the four DC powered ADVs (one per steam generator) are used in the NCC analysis. This scenario demonstrates that the plant can be cooled down to SDC entry conditions using only safety grade equipment and maintaining pressure control (holding a 20 degree subcooling margin in the reactor vessel upper head (RVUH)) for a loss of offsite power (LOOP) event with the most limiting single failure.

3. The temperature and pressure conditions considered in the NCC analysis are within the bounds of the CENTS code. The reactor coolant system (RCS) is kept above the saturation pressure corresponding to the RVUH temperature; therefore, no two-phase conditions are present during the NCC analysis and no unexpected thermal-hydraulic phenomena are predicted.

4. The decay heat table in the St. Lucie Unit 2 CENTS code is based on the 1979 ANS 5.1 Standard Decay Heat Curve including 2σ uncertainty and accounts for the affects of neutron capture and long term actinides. The decay heat curve bounds fuel designs with up to: 5 weight percent fuel enrichment; fuel burnups to 73,000 MWd/MTU; and operating cycles up to 24 months in duration. Therefore, the basis for the decay heat curve used in the NCC analysis bounds the fuel design and operating cycle lengths anticipated as part of the St. Lucie Unit 2 EPU design.

5. The required condensate storage tank (CST) inventory for NCC is calculated as 178,200 gallons using the CENTS code and is based on the feedwater pump flow during cooldown. This volume is within the TS requirement of 307,000 gallons.

6. The NCC analysis assumes that the operators do not depressurize the RVUH below a 20 degree subcooling margin (to preclude drawing a void in the upper head). The analysis demonstrates that the plant can be cooled to shutdown cooling entry conditions using only safety grade equipment.

ATTACHMENT 3

Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request

Westinghouse Electric Company Affidavit for Withhold Proprietary Information from Public Disclosure

This coversheet plus 7 pages

Westinghouse

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USA

U.S. Nuclear Regulatory Commission
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Rockville, MD 20852

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e-mail: greshaja@westinghouse.com
Proj letter: FPL-11-297

CAW-11-3315

November 18, 2011

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: "Response to Requests for Additional Information (RAI SRXB-64) for the St. Lucie Unit 2 Extended Power Uprate License Amendment Request" (Proprietary)

References:

1. NRC E-Mail, T. Orf (NRC) to C. Wasik (FPL), "St. Lucie 2 EPU - Draft RAIs Reactor Systems Branch and Nuclear Performance Branch (SRXB and SNPB)," September 6, 2011, 12:19 PM.

The proprietary information for which withholding is being requested is that included in the response to the Request for Additional Information (RAI) designated as "SRXB-64" transmitted by Reference 1, and further identified in Affidavit CAW-11-3315 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Florida Power and Light.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-11-3315, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company LLC, Suite 428, 1000 Westinghouse Drive, Cranberry Township, Pennsylvania 16066.

Very truly yours,

for J. A. Gresham, Manager
Regulatory Compliance

Enclosures

AFFIDAVIT

STATE OF CONNECTICUT:

ss Windsor Locks

COUNTY OF HARTFORD:

Before me, the undersigned authority, personally appeared C. M. Molnar, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

C. M. Molnar, Senior Engineer
Regulatory Compliance

Sworn to and subscribed before me
this 18th day of November 2011

Joan Gray

Subscribed and sworn to before me, a Notary Public, in and for County of Hartford and State of Connecticut this 18 day of November, 2011.

JOAN GRAY
Notary Public
My Commission Expires January 31, 2012

(1) I am Senior Engineer, Regulatory Compliance, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse Application for Withholding Proprietary Information from Public Disclosure accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in the response to Request for Additional Information (RAI) "SRXB-64", for submittal to the Commission, being transmitted by Florida Power and Light letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The RAI identified above is included in NRC E-Mail, T. Orf (NRC) to C. Wasik (FPL), "St. Lucie 2 EPU - Draft RAIs Reactor Systems Branch and Nuclear Performance Branch (SRXB and SNPB)," September 6, 2011, 12:19 PM. The proprietary information as submitted by Westinghouse is that which supports the St. Lucie Unit 2 Extended Power Uprate (EPU) License Amendment Request (LAR), and may be used only for that purpose.

This information is part of that which will enable Westinghouse to:

(a) Support the St. Lucie Unit 2 EPU LAR by justifying the calculated peak centerline temperature for the subcritical uncontrolled CEA withdrawal event under EPU conditions.

Further this information has substantial commercial value as follows:

(a) The information reveals aspects of Westinghouse analytical methodology that could facilitate competitors' future analyses.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculations and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

Proprietary Information Notice

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

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