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Ken Peters
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W3F1-2004-0061

July 28, 2004

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

SUBJECT: Supplement to Amendment Request NPF-38-249,
Extended Power Uprate
Waterford Steam Electric Station, Unit 3
Docket No. 50-382
License No. NPF-38

REFERENCES:
1. Entergy Letter dated November 13, 2003, "License Amendment Request NPF-38-249 Extended Power Uprate"
2. NRC Letter dated June 21, 2004, "Waterford Steam Electric Station, Unit 3 (Waterford 3) – Request for Additional Information Related to Revision to Facility Operating License and Technical Specifications - Extended Power Uprate Request (TAC No. MC1355)"
3. Entergy Letter dated May 26, 2004, "Supplement to Amendment Request NPF-38-249, Extended Power Uprate"
4. Entergy Letter dated July 14, 2004, "Supplement to Amendment Request NPF-38-249, Extended Power Uprate"

Dear Sir or Madam:

By letter (Reference 1), Entergy Operations, Inc. (Entergy) proposed a change to the Waterford Steam Electric Station, Unit 3 (Waterford 3) Operating License and Technical Specifications to increase the unit's rated thermal power level from 3441 megawatts thermal (MWt) to 3716 MWt.

By letter (Reference 2), the Nuclear Regulatory Commission (NRC) staff requested additional information (RAI) related to reactor systems. Entergy's responses to 40 of the 61 questions are contained in Attachment 1 to this letter. Responses to the remainder of the questions will be provided by August 10, 2004. The need to answer the RAI in two parts was discussed with the Waterford 3 Nuclear Reactor Regulation (NRR) Project Manager.

Three additional items are addressed in this supplement.

- Entergy and members of your staff held discussions regarding the approach to be taken for a reactor vessel internals management program. A revised commitment,

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based on these discussions, is provided in Attachment 2 and supersedes the commitment previously made in Reference 3.

- On June 24, 2004, and July 8, 2004, Entergy and members of your staff held calls regarding EPU dose assessment and atmospheric dispersion calculations. Attachment 3 provides additional information on this subject based on these calls.
- Engineering reviews have identified a slight non-conservatism in the feedwater line volume (270 ft^3 vs. 274 ft^3) assumed in determining the mass and energy additions to the containment following the limiting main steam line break (MSLB) event. The mass and energy additions were used to determine the EPU peak containment pressure and temperature reported in Reference 1. The revised volume increases the MSLB peak containment pressure (as reported in Attachment 5, Section 2.5.2.1, Table 2.5-2 of Reference 1) from 41.83 psig to 41.88 psig which is still below the acceptance limit of 44 psig. The MSLB peak containment temperature increased slightly from 394.4 °F to 394.7 °F. The LOCA peak containment pressure and temperature results reported in Reference 1 are not impacted by the additional feedwater line volume.

There are no technical changes proposed. The no significant hazards consideration included in Reference 4 is not affected by any information contained in this letter. The submittal includes two new commitments and a revised commitment as summarized in Attachment 4.

If you have any questions or require additional information, please contact D. Bryan Miller at 504-739-6692.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 28, 2004.

Sincerely,

KEP/dbm

Attachments:
1. Response to Request for Additional Information
2. Revised Commitment Regarding Reactor Vessel Internals Management
3. Additional Information Regarding EPU Dose Assessment
4. List of Regulatory Commitments

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Attachment 1 To

W3F1-2004-0061

Response to Request for Additional Information

Response to Request for Additional Information

Question 1:

Please provide a quantified evaluation of the time needed for plant cooldown to achieve cold shutdown conditions per RSB BTP 5-1 (natural circulation cooldown using only safety grade equipment), and for plant cooldown per the requirements of Appendix R to Title 10 of the Code of Federal Regulations (10 CFR), Part 50 (regarding fire protection) for Waterford 3 at extended power uprate (EPU) power level and the current power level.

Response 1:

RSB 5-1 Cooldown:

A revised evaluation was prepared for the Waterford 3 plant for Extended Power Uprate (EPU) conditions that demonstrates the time required to achieve cold shutdown conditions of 200°F per the requirements of RSB BTP 5-1 for a natural circulation cooldown, with a loss of off-site power using only safety grade equipment and assuming the worst single failure. The analysis is done in two phases; the first is an analysis of cooldown from normal operating pressures and temperatures to conditions suitable for the initiation of shutdown cooling operation, followed by analysis that models using the shutdown cooling system (SDCS) to cool to RCS temperature of 200°F.

The cumulative results table provides current analysis of record results as well as the revised results for the EPU condition. The results demonstrate that the Waterford 3 plant will maintain its ability to cool the RCS following shutdown and provide decay heat removal consistent with Branch Technical Position 5-1 following power uprate to 3716MWt.

Cumulative Results Table for RSB 5-1 Analyses

	Current Duration	**EPU Duration**
Limiting Failure:	ADV Failure	DC Bus Failure
Cooldown Method:		
Nat. Circ. Cooldown to reach 350°F	Start: 0.0 hrs. End: 25.1 hrs. Duration: 25.1 hrs.	Start: 0.0 hrs. End: 8.9 hrs. Duration: 8.9 hrs.
Shutdown Cooling 350°F to 200°F	Start: 25.1hrs. after shutdown End: 28.1 hrs. Duration: 3.0 hrs.	Start: 9.0 hrs. after shutdown End: 34.7 hrs. Duration: 25.7 hrs.
Total Time	28.1 hrs.	*34.7 hrs.

* Total duration conservatively ignores small disconnect between end of steam generator cooldown and start of SDCS cooldown.

The limiting failure case for EPU is the loss of the DC bus failure resulting in the longest cooldown time. This scenario fails one emergency diesel generator and control logic of one atmospheric dump valve (ADV). In this scenario only one train of safety related equipment is available, and in particular only one SDCS train is available for cooldown from 350°F to 200°F. Loss of control of the ADV means that temporarily only one steam generator (SG) is available for cooldown to 350°F. The transient assumes local manual control of the ADV by the time cooldown of the RCS commences after the required four hour hold period at HZP conditions resulting in both ADV/SG being available. Note that the assumption of manual action at four hours is a change from the current RSB BTP 5-1 analysis, which does not credit operator manual action until after ten hours, the minimum point in time when ADV nitrogen supply is exhausted. Based upon the results of the EPU analysis, the Waterford 3 plant is capable of being cooled to a cold shutdown condition with only offsite or onsite power available within a reasonable period of time following shutdown, assuming the most limiting single failure. Consistent with current Waterford 3 license basis, 36 hours is considered a reasonable time period.

For current power conditions, the limiting single failure is considered an ADV failure. In this scenario the failed ADV is permanently unavailable, forcing a cooldown on a single steam generator. Once on SDC the cooldown proceeds rapidly, as two trains are available. It should be noted that the current analysis is conservatively based upon an assumed 108% of current core power (3661 MWt). Also note that the change in worst single failure is not a direct result of the EPU conditions but is the consequence of more accurate natural circulation mixing factors used in the first phase of the cooldown during the natural circulation cooldown.

Appendix R Cooldown

10CFR 50 Appendix R requires the safety function for hot shutdown structures, systems and components to be such that " one train of equipment necessary to achieve hot shutdown from either the control room or emergency control stations(s) must be maintained free of fire damage by a single fire including an exposure fire." In addition it allows the safety function for cold shutdown structures, systems or components to suffer fire damage by the statement "Both trains of equipment necessary to achieve cold shutdown may be damaged by a single fire, but fire damage must be limited so that at least one train can be repaired or made operable within 72 hours using onsite capability." Thus the Appendix R requirements are prescriptive in that at least one train required for hot shutdown must be available and at least one train required for cold shutdown must be available within 72 hours. The Waterford 3 post fire safe shutdown compliance strategy does not rely on any repairs to achieve hot standby and the only repairs credited for cold shutdown are the replacement of fuses that may have blown prior to the transfer of control from the Control Room to the Remote Shutdown Room.

The Appendix R fire analysis is based on maintaining one train of the redundant systems normally credited for safe shutdown.

In regards to the Appendix R analysis hot shutdown related actions are provided specific completion times and cold shutdown related actions are not time critical. The analysis provided for other plant transients bound the impacts of the Appendix R fire event. Thus there is essentially no difference between the Extended Power Uprate (EPU) power level and the current power level with respect to the Appendix R analysis and associated time required for plant cooldown.

Question 2:

Clarify the statement in Section 2.6.4.4 of your EPU submittal, "the current limiting conditions for operations for time based reduced flow rate are acceptable at EPU condition."

Response 2:

The complete EPU Report statement in Section 2.6.4.4, "With regard to the Technical Specifications limitations, the current limiting conditions for operation (LCO) for time based reduced flow rates are acceptable at EPU condition," is in reference to the Technical Specification Section 3/4.9.8 Shutdown Cooling and Coolant Circulation, High Water Level and Low Water Level. Specifically, the double asterisk (**) footnote to Surveillance Requirements 4.9.8.1 and 4.9.8.2 states:

> *The minimum flow may be reduced to 3000 gpm after the reactor has been shut down for greater than or equal to 175 hours or by verifying at least once per hour that the RCS temperature is less then (Sic.) 135°F. The minimum flow may be reduced to 2000 gpm after the reactor has been shut down for greater than or equal to 375 hours.*

These time-based minimum shutdown cooling system (SDCS) flow rates are provided to facilitate operations during plant outages. The analysis that supports these time limits has been evaluated and it is concluded that EPU operation will not affect these requirements. At these extended shutdown times, the decay heat is conservatively not sufficient to heatup the RCS, provided that the minimum SDC flow is supplied even though the EPU plant power level has resulted in a slight decay heat increase. Alternately, it can be explained that there was sufficient conservatism in the current analysis supporting the pre-EPU conditions for the time limits (e.g. 175 hours for 3000 gpm or 375 hours for 2000 gpm) to remain acceptable when considering the higher EPU decay heat load.

Question 3:

Section 2.6.4.3 states that the low temperature overpressure (LTOP) calculations have been revised. Please submit: (1) the mass and energy input transient assumptions and results, (2) the revised LTOP enable setpoint, and (3) the vent capacities for NRC staff review.

Response 3:

The Low temperature overpressure protection (LTOP) transient calculations have been revised for the Extended Power Uprate conditions as stated in the Power Uprate Report (Attachment 5 to Entergy letter W3F1-2003-0074) Section 2.6.4.3.

With regard to requested Item (1): The assumed transients are described as follows:

The design basis mass addition event is assumed to result from an inadvertent Safety Injection Actuation Signal (SIAS) in the LTOP temperature range, causing two high pressure safety injection (HPSI) pumps and three charging pumps to operate. To maximize the pressure transient, a water solid RCS is assumed, with letdown isolated, and only a single SDC relief valve is assumed available. These assumptions are the same as the current Licensing Basis. In addition, for conservatism, and new for EPU, it is assumed that energy from decay heat, four reactor coolant pumps and all pressurizer heaters contribute to the rapid pressurization. Of all these assumptions, the only parameter directly affected by EPU is the assumed amount of decay heat, which represents a small portion of the total energy considered in the transient. The peak transient pressure was calculated as 471 psia.

The design basis energy addition event is the startup of the first reactor coolant pump (RCP) with a reverse temperature differential across the steam generators. To maximize the transient results, a steam generator to RCS temperature difference of 100°F is assumed with the RCS water solid and letdown isolated. Additional energy input from decay heat and all pressurizer heaters is assumed along with the heat from the started RCP. These assumptions are the same as the current Licensing Basis. Of all these assumptions, the only parameter directly affected by EPU is the assumed amount of decay heat, which represents a small portion of the total energy considered in the transient. The peak transient pressure was calculated as 467 psia.

To provide relevance to these transient results, note that within the LTOP Enable region (less than 230°F) the limiting analysis pressure that the LTOP controls must protect is 554.1 psia. This limit is based upon an ASME Appendix G Pressure-Temperature limits evaluation that supports EPU conditions.

With regard to requested Item (2): The LTOP setpoint was not revised as a result of EPU. LTOP protection at Waterford 3 is provided by the two shutdown cooling system (SDCS) relief valves located in the SDCS suction lines with a setpoint of 430 psia. The setpoint of these valves protects the SDCS from overpressure and performs the concurrent role of LTOP control.

With regard to requested Item (3): The vent capacities were not revised as a result of EPU. The relief protection for LTOP control of the Waterford 3 plant is provided by the SDCS relief valves. These valves have a rated relief capacity of 3345 gpm for a setpoint of 430 psia at full accumulation. As noted, for conservatism, the mass addition and energy addition transient models only assumes the functioning of one relief valve.

Question 4:

The small break loss-of-coolant accident (SBLOCA) methodology (S2M) which was used to perform the Waterford 3 analyses for the uprated power does not apply at the requested uprated power, since the sensitivity studies supporting the S2M methodology were performed at a lower power. The sensitivity studies to justify applicability of the S2M at a higher power are plant-specific and do not have generic applicability. Provide justification that the S2M applies to Waterford 3 at the requested uprated power. (Please see the NRC staff safety evaluation report for Palo Verde Nuclear Generating Station fuel transition)

Response 4:

Section 4.1 of the NRC staff safety evaluation report for Palo Verde Nuclear Generating Station (PVNGS) (Reference 4.1) noted in Question 4 states that the sensitivity study described in Reference 4.2 demonstrates that the S2M methodology applies specifically to the proposed operating conditions for PVNGS Unit 2. The Reference 4.2 study analyzed the three cases originally described in Appendix E of the S2M topical report (Reference 4.3). The subject study was repeated for Waterford 3. The following paragraphs summarize the results of the study.

The study was performed for the limiting break of the Waterford 3 extended power uprate SBLOCA analysis (Attachment 5 of Reference 4.4), namely, a 0.055 ft^2 break in a reactor coolant pump discharge leg. As prescribed in Appendix E of the S2M topical report, the metal-water reaction rate model was turned off in each case. The following three cases were run.

Case 1 – S1M methodology with the multiplier on the decay heat model adjusted to achieve a peak cladding temperature (PCT) close to 2200°F.
Case 2 – S2M methodology with the same decay heat multiplier used in Case 1.
Case 3 – S1M methodology with a decay heat multiplier equal to the multiplier used in Cases 1 and 2 divided by 1.2. In other words, the decay heat multiplier for Cases 1 and 2 is 1.2 times the multiplier for Case 3.

The PCTs for the three cases are tabulated below.

Case No.	Description	PCT (°F)
1	S1M@1.2	2179
2	S2M@1.2	1789
3	S1M@1.0	1613

The difference in PCT between Cases 1 and 2 is 390°F. This difference is a measure of the change in PCT associated with the model revisions introduced in the S2M methodology. Note that the S2M model revisions were made to the hot rod heatup code, PARCH, and do not impact the Reactor Coolant System (RCS) thermal-hydraulic analysis, which is performed by the CEFLASH-4AS code. The difference in PCT is comparable to that calculated in the study for PVNGS Unit 2 (370°F) and in Appendix E of the S2M topical report (364°F). This shows that, for the conditions of the study, the model revisions introduced in the S2M result in approximately the same reduction in PCT for a wide range of core powers and other plant-specific conditions.

The difference in PCT between Cases 1 and 3 is 566°F. This is a measure of the sensitivity of the S1M RCS thermal-hydraulic and hot rod heatup analyses for Waterford 3 to a 20% change in core decay heat. The corresponding differences from the PVNGS Unit 2 and S2M topical report studies were 920°F and 1413°F, respectively. This wide range of differences is due, in large part, to plant-specific differences in the sensitivity of the RCS thermal-hydraulic response to changes in core decay heat.

The ratio of the two differences in PCT for the Waterford 3 study is 0.69. In the context of the study, this ratio shows that, for Waterford 3 at the extended power uprate conditions, the improvement in PCT due to the S2M model revisions is equivalent to approximately 69% of the difference in PCT due to a 20% change in core decay heat using the S1M methodology. Note that this is not equivalent to saying that the Waterford 3 extended power uprate SBLOCA analysis "uses up" 69% (and, therefore, retains 31%) of the margin associated with the 1.2 decay heat multiplier required by Appendix K to 10 CFR 50. The Waterford 3 extended power uprate SBLOCA analysis retains 100% of the margin associated with the 1.2 decay heat multiplier since it was performed with the 1.2 multiplier as required by Appendix K to 10 CFR 50.

Lastly, as done in the PVNGS Unit 2 study, the PCTs for the three cases are combined into a single figure-of-merit defined as follows:

$$1 + 0.2 * [\, 1 - (PCT_{Case\,1} - PCT_{Case\,2}) \,/\, (PCT_{Case\,1} - PCT_{Case\,3})]$$

The value of the figure-of-merit for Waterford 3 at the extended power uprate conditions is 1.062.

References

4.1 B.M. Pham (NRC) to G.R. Overbeck (APS), "Palo Verde Nuclear Generating Station, Unit 2 (PVNGS-2) – Issuance of Amendment on Replacement of Steam Generators and Uprated Power Operations (TAC No. MB3696)," September 29, 2003.

4.2 102-04974-CDM/TNW/RAB, D. Mauldin (APS) to Document Control Desk (NRC), "Palo Verde Nuclear Generating Station (PVNGS) Unit 2, Docket No. STN 50-529, Response to Request for Additional Information Regarding Steam Generator Replacement and Power Uprate License Amendment Request," July 25, 2003.

4.3 CENPD-137, Supplement 2-P-A, "Calculative Methods for the ABB CE Small Break LOCA Evaluation Model," April 1998.

4.4 W3F1-2004-0052, J.E. Venable (EOI) to Document Control Desk (NRC), "Supplement to Amendment Request NPF-38-249, Extended Power Uprate, Waterford Steam Electric Station, Unit 3, Docket No. 50-382, License No. NPF-38," July 14, 2004.

Question 5:

Please confirm that the generically approved LOCA analysis methodologies used for the Waterford 3 uprate LOCA analyses continue to apply specifically to the Waterford 3 plant by: 1) showing that Waterford 3 operating at the uprated power is bounded by the assumptions used in analyses used to support the approval of the generic LOCA methodologies identified in the response to Question 4; and 2) providing a statement to confirm that Waterford 3 and its vendor continue to have ongoing processes which assure that LOCA analysis input values bound the as-operated plant values for those parameters. (The statement should be identical to the one in the question in order to avoid providing extraneous and/or irrelevant information which will not address the question.)

Response 5:

The generically approved methodologies (i.e., evaluation models) used for the Waterford 3 extended power uprate Emergency Core Cooling System (ECCS) performance analyses apply specifically to Waterford 3 since:

1) Waterford 3 operating at the extended power uprate is bounded by the assumptions used in the analyses that support the approval of the S2M evaluation model as shown in the response to Question 4; and,
2) Waterford 3 and its vendor, Westinghouse Electric Company LLC, continue to have ongoing processes, which assure that LOCA analysis input values bound the as-operated plant values for those parameters.

Question 6:

What are the calculated large break LOCA and SBLOCA results per 10 CFR 50.46 (b) for Waterford 3 at the uprated power for both the new fuel and the resident fuel? Include in the evaluation of the local oxidation consideration of pre-event and post accident inside clad and outside clad oxidation.

Response 6:

The calculated results per 10 CFR 50.46(b) for Waterford 3 at the uprated power are summarized on page 2.12-4 of the Waterford 3 Extended Power Uprate Report (Attachment 5 to Reference 6.1) for large break LOCA (LBLOCA) and on page 3 of Attachment 5 of Reference 6.2 for SBLOCA. The results for both analyses are repeated below. The results are applicable to both new (i.e., fresh) and resident (i.e., previously burned) fuel.

Parameter	Criterion	LBLOCA	SBLOCA
Peak Cladding Temperature	≤2200°F	2164°F	2018
Maximum Cladding Oxidation	≤17%	8.7%	13.1%
Maximum Core-Wide Cladding Oxidation	≤1%	<0.99%	<0.99%
Coolable Geometry	Yes	Yes	Yes

In accordance with the evaluation models used in the analyses (i.e., the 1999 EM for LBLOCA and the S2M for SBLOCA), the cladding oxidation model was initialized with a thin layer of pre-accident oxidation on both the inside and outside of the cladding regardless of the burnup that was analyzed. The evaluation models use a thin layer of pre-accident oxidation since, in general, a thin layer maximizes the post-accident cladding oxidation as well as the PCT.

Maximum pre-accident oxidation as a function of rod average burnup may be obtained from Figure 4.1.2.a-1 of Reference 6.3 for Combustion Engineering 16x16 PWR fuel (with Zircaloy-4 cladding). Reference 6.3 was generically approved by NRC for licensing applications in Reference 6.4. The information contained in Figure 4.1.2.a-1 is Westinghouse Electric Company LLC proprietary information.

The fuel performance and ECCS performance analyses for the Waterford 3 extended power uprate are applicable to core designs for which a fuel rod may operate at the PLHGR of 13.2 kW/ft for rod average burnups up to 32 MWD/kg. Figure 4.1.2.a-1 of Reference 6.3 may be used to estimate the amount of pre-accident oxidation at 32 MWD/kg.

Note that Figure 4.1.2.a-1 provides maximum pre-accident oxide thickness in units of microns. An oxide thickness in units of microns can be converted to units of % of total cladding thickness before oxidation using the following two step process.

- Convert the oxide thickness (units of microns) to the corresponding cladding wastage thickness (units of microns) by dividing the oxide thickness by the Pilling-Bedworth ratio, 1.56.

- Convert the cladding wastage thickness (units of microns) to % of total cladding thickness before oxidation by dividing it by the cladding thickness before oxidation (635 microns for the Waterford 3 cladding) and multiplying the result by 100%.

References

6.1 W3F1-2003-0074, J.E. Venable (EOI) to Document Control Desk (NRC), License Amendment Request NPF-38-249, Extended Power Uprate, Waterford Steam Electric Station, Unit 3, Docket No. 50-382, License No. NPF-38," November 13, 2003.

6.2 W3F1-2004-0052, J.E. Venable (EOI) to Document Control Desk (NRC), "Supplement to Amendment Request NPF-38-249, Extended Power Uprate, Waterford Steam Electric Station, Unit 3, Docket No. 50-382, License No. NPF-38," July 14, 2004.

6.3 CEN-386-P-A, "Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/kgU for Combustion Engineering 16x16 PWR Fuel," August 1992.

6.4 A.C. Thadani (NRC) to A.E. Scherer, "Generic Approval of C-E Topical Report CEN-386-P, 'Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/kg for Combustion Engineering 16x16 PWR Fuel (TAC No. M82192)'," June 22, 1992.

Question 7:

Verify that the recently discovered error in the S2M methodology has been fixed in the Waterford 3 LOCA model.

Response 7:

The recently discovered error in the S2M methodology has been fixed in the Waterford 3 extended power uprate SBLOCA analysis. The error referred to in the question was an error in the CEFLASH-4AS computer code. The error is described in Reference 7.1. The Waterford 3 extended power uprate SBLOCA analysis used the corrected version of CEFLASH-4AS.

Reference

7.1 W3F1-2002-0044, R.D. Peters (EOI) to Document Control Desk (NRC), "Waterford 3 SES, Docket No. 50-382, License No. NPF-38, Annual Report on Westinghouse Electric Company LLC Combustion Engineering Emergency Core Cooling System Performance Evaluation Models," May 7, 2002.

Question 8:

Discuss the design of the Waterford 3 emergency core cooling system (ECCS) switch over from the injection mode to the ECCS sump recirculation mode. What was the decay heat source assumed in the design of the ECCS switch over from the injection mode to the ECCS sump recirculation mode for the present power? Does this assumed heat source change for the uprated power? Is the timing of the switch over affected? Please explain.

Response 8:

The design of ECCS switchover from injection mode to ECCS sump recirculation is such that at RAS (the recirculation actuation signal) initiation the delivered flow of 75% of one HPSI pump at sump conditions is sufficient to remove the decay heat load at that time. The minimum elapsed time is twenty minutes. To support EPU, an evaluation of the decay heat demand based upon the 1979 ANS Standard Decay Heat curve at twenty minutes and a core power assumption of 3735 MWt was compared to HPSI performance and found acceptable. EPU has no direct effect on the timing of the switchover. The timing of the switchover is a consequence of the minimum available useable volume of the refueling water storage pool and the maximum ECCS pump demand. While neither of these parameters is changed by EPU, a confirmatory evaluation was performed to assure that current plant assumptions and limits ensure that there is greater than twenty minutes prior to RAS.

Question 9:

The Waterford 3 SBLOCA analyses take credit for the operation of the steam generator atmospheric dump valves (ADVs). Show that the ADVs are fully safety grade for this use by identifying all ADV components and supporting systems needed to support the SBLOCA operation, and show that these components and supporting systems are safety grade. (e.g, if the ADVs rely on instrument air, show that the instrument air system is safety grade and has sufficient long term capacity to support repeated cycling of the valves). If the valves are only qualified to open and not re-seat, show how the RCS pressure will be controlled to both keep the core covered and avoid cold overpressure for all break sizes. If stopping of ECCS pumps is involved show that the pumps can be re-started if and when needed.

Response 9:

The safety class of Waterford 3's structures, systems and components is discussed in FSAR Section 3.2-2. The specific safety class for the ADVs and the supporting systems is given in FSAR Table 3.2-1. A summary is provided below:

- The ADVs are designed to Safety Class 2, Seismic Class 1 requirements and are protected by barriers that are designed to withstand flooding, tornado winds, and/or missile loads.
- The supporting instrumentation for the ADV are designed to Safety Class 1E, Seismic Class 1 requirements and are protected by barriers that are designed to withstand flooding, tornado winds, and/or missile loads.
- The supporting compressed air system for the ADVs is designed to Safety Class 3, Seismic Class 1 requirements and is protected by barriers that are designed to withstand flooding, tornado winds, and/or missile loads.
- The supporting electrical systems for the ADVs are designed to Safety Class 1E, Seismic Class 1 requirements and are protected by barriers that are designed to withstand flooding, tornado winds, and/or missile loads.

The primary safety function of the ADVs is to throttle to maintain the RCS temperature following a loss of offsite power. A secondary safety function of the ADV is to close for containment isolation. The new function assigned for EPU is pressure control for SBLOCA. To perform these functions, the ADVs are designed to open and re-seat as required as stated in FSAR Table 3.9-9. Stopping/re-starting of the ECCS pumps is not required for pressure control in the Small Break LOCA analysis. Since the ADVs normal air supply is designated as non-safety related, a back-up source of nitrogen from Safety Class 3, Seismic Category I accumulators is available. The backup nitrogen accumulators are sized to operate the ADVs for 10 hours upon loss of the normal air supply. The ADVs also can be operated manually if required after the nitrogen supply is exhausted. The ADV manual function is credited for the RSB BTP 5-1 cooldown analysis discussed in FSAR Section 9.3.6.3.3 and long term cooling discussed in FSAR Section 6.3.3.4.

The ADV control loop has been evaluated and supports the new ADV small break LOCA mitigation function. The existing control loop will be modified such that the setpoint can be monitored on the plant monitoring computer. This connection to the non-safety related plant monitoring computer will meet applicable isolation requirements.

Question 10:

a. Your February 5, 2004, Slide 5 stated that RCS flow rate would increase from 44,522 pound mass per second (lbm/sec) to 45,808 lbm/sec. Please provide the basis for this change.

b. Table 2.6-2 of your submittal states the minimum rate is unchanged from 148.0 X 10^6 pound mass per hour (41,411 lbm/sec) but it also states that the core and reactor vessel differential pressures increase in each of the Table's three columns and the nominal film coefficient is also shown to increase for the EPU. Please clarify this information with respect to ensuring that the 41,411 lbm/sec is bounding, that the film coefficient information is correct, and with respect to the Item 1.a values.

c. Please also address the stated core flow rates with respect to the above.

(We note similar information is provided elsewhere in your submittal, such as in Table 2.12-1.)

Response 10:

a. Information that addresses this question was previously submitted for NRC staff review. Please reference Attachment 2 to Entergy Operations, Inc. letter (W3F1-2004-0037,) "Supplement to Amendment Request NPF-38-249, Extended Power Uprate," dated May 12, 2004 for the answer to this question. As discussed in that letter, Waterford 3 review of RCS flow data led to increasing the assumed best-estimate nominal flow rate to 110% of design flow instead of the previously assumed value of 107%.

b. The minimum RCS flow rate of 148.0 x10^6 lbm/hr is unchanged from Cycle 1 and still represents a lower bound for the uprated core conditions. This flow rate corresponds to 41,111 lbm/sec, not 41,411. The core and vessel pressure drops and nominal film coefficient depend on other parameters than just the RCS flow rate. The increase in core and vessel pressure drops in going from Cycle 2 to Cycle 12 are primarily due to mechanical design changes, e.g. GUARDIAN™ Grid, and secondarily to changes in the nominal core operating point, primarily temperature. The changes in the nominal core operating point impacted the water properties and therefore the pressure drops. The relatively small increase in core and vessel pressure drops in going from Cycle 12 to EPU as depicted in Table 2.6-2 of the submittal are driven solely by the change in acceleration pressure drop due to the slight changes in the nominal core operating point, again primarily temperature, associated with the power uprate. The nominal film coefficient also depends on the nominal core operating point characteristics. Table 2.6-2 in the Licensing Submittal shows the same nominal film coefficient value for both Cycle 12 and the uprated core due to rounding.

c. Please see the response to part b above.

Question 11:

There are a number of references where the number of ADVs credited for the licensing bases is increased to two. Please address how this meets applicable single failure criteria.

Response 11:

To be provided in a later submittal.

Question 12:

What was the previously assumed numerical value of the volume in which boric acid accumulates for long term cooling analysis? What is the numerical value assumed for the EPU?

Response 12:

A value of 1591 ft^3 was used for the volume in which boric acid accumulates in the previous post-LOCA long term cooling analysis (i.e., the analysis for the pre-EPU power level, which is described in Section 6.3.3.4 of the Waterford 3 FSAR). A value of 1146 ft^3 was used for the volume in which boric acid accumulates in the EPU post-LOCA long term cooling analysis. The value used in the EPU analysis is smaller than the value used in the pre-EPU analysis because, as described in Section 2.12.5.1of the Extended Power Uprate Report (Attachment 5 to Reference 12.1), the value used in the EPU analysis did not include any of the volume below the top of the core support plate (i.e., in the lower plenum of the reactor vessel).

References

12.1 W3F1-2003-0074, J.E. Venable (EOI) to Document Control Desk (NRC), License Amendment Request NPF-38-249, Extended Power Uprate, Waterford Steam Electric Station, Unit 3, Docket No. 50-382, License No. NPF-38," November 13, 2003.

Question 13:

Please confirm that the Table 2.12-12 values for the boric acid makeup tanks, refueling water storage pool, and safety injection tanks are those used in the long term cooling analyses.

Response 13:

The values for the boric acid makeup tanks, refueling water storage pool, and safety injection tanks listed in Table 2.12-12 are the values used in the post-LOCA long-term cooling analysis.

Question 14:

Please state the time by which the procedure(s) will reasonably ensure initiation of hot leg injection and provide a copy of the procedure(s). Provide the basis for the stated time.

Response 14:

Step 46 of OP-902-002, Loss of Coolant Recovery, currently states:

> IF elapsed time from the start of the event is between 2 and 4 hours **AND ANY** of the following conditions exist:
> - RCS subcooling is less than 28°F based on representative CET temperature
> - Pressurizer level is less than 7%
> - Reactor vessel level indicates at least one of the following:
>   - QSPDS REACTOR VESSEL LEVEL 5 is voided
>   - VESSEL LEVEL PLENUM is less than 80%
>
> **THEN** <u>REFER TO</u> Appendix 15, "Hot and Cold Leg Injection" and <u>establish</u> simultaneous hot and cold leg injection.

The time period in this step will be changed from between 2 and 4 hours to between 2 and 3 hours for Extended Power Uprate. This commitment is noted in Section 2.9.1 of the PUR.

This change is required as a result of the Post-LOCA Long Term Cooling ECCS Performance Analysis for Waterford 3 at 3716 MWt Extended Power Uprate. This analysis concludes that "...the core boric acid concentration is maintained below the boric acid solubility limit following a large break LOCA when a simultaneous hot and cold side injection flow rate of 372 gpm or more (i.e., at least 372 gpm to the hot side and to the cold side of the RCS) is started between 2 and 3 hours after the start of the LOCA. When a simultaneous hot and cold side injection flow rate of 372 gpm is started at 3 hours post-LOCA, the maximum boric acid concentration in the core is 23.576 wt% at 3 hours post-LOCA, a margin of 4.024 wt% to the solubility limit of 27.6 wt%."

The earliest time to start hot leg injection is based on a calculation of when the hot leg steam velocity falls below the velocity required to entrain the hot side injection. Analysis shows that this time is approximately 114 minutes, which is bounded by the 2 hour requirement.

The reasons for the 2 to 3 hour time limit are noted in Section 2.12.5.3 of the PUR.

QSPDS provides three level indicators for the reactor head level and five indicators for the plenum level. On QSPDS these levels are numbered from 48% reactor head level, number 1, to 0% reactor plenum level, number 8. These levels also input to a chart recorder that records percentage reactor head level and percentage reactor plenum level (two pins). A void in REACTOR LEVEL 5 indicates that reactor plenum level is less than 61% plenum level. Consequently, if this level is voided, then the plenum level is less than 61%.

The location of the detectors is shown in FSAR Appendix 1.9A, figure 1.9A-5.

Establishing hot/cold leg injection is a three step procedure that requires opening four valves and shutting 2 valves. All of these valves are operated from the same control panel in the control room. This task is a job performance measure (JPM) for license operators. The estimated time listed for the JPM is 10 minutes. Consequently, the time window of 1 hour is more than sufficient time to establish hot/cold leg injection.

Question 15:

In your evaluation of non-LOCA transient analyses, there are a few events for which the following conclusion has been drawn, "The analysis has been evaluated for EPU, the final safety analysis report (FSAR) results remain bounding, and a complete reanalysis was not required." Please provide a quantitative evaluation of these events to show that the consequences of these events at EPU conditions are bounded by the current analysis in FSAR.

Response 15:

Table 2.13.0-1 does contain reference to several events for which the results, as presented in the FSAR are unaffected by the increase in rated thermal power.

<u>Section 2.13.1.3.2, Mode 3 and 4 All Rods In (ARI) Steam Line Break</u>

The increase in rated thermal power has not altered the two important driving parameters in the subcritical SLB analysis. It has not altered the temperature dependent SHUTDOWN MARGIN figure (applicable for subcritical conditions) in the plant COLR. The reactivity balance performed in the reload analysis process for the lower mode SLB analysis assumes, due to the reduced initial primary system temperatures in the lower modes, that the minimum RCS temperatures reach 212 °F. This assumption would still be bounding.

Therefore the results as currently reported in the FSAR remain valid.

<u>Section 2.13.4.1.5, Inadvertent Boron Dilution</u>

The inadvertent boron dilution analysis is performed to provide values for the Boron Dilution Alarm and, when the alarm is inoperable, required boron measurement surveillance frequencies in the COLR, which ensure that adequate time remains for the operators to take corrective action.

The existing analysis has identified combinations of Inverse Boron Worth (IBWs) and Critical Boron Concentrations (CBCs) which support the current setpoints and surveillance frequencies. The reload process checks actual core designs against these combinations for verification of the setpoints.

As the increase in rated thermal power has not affected the RCS volume or the charging pump capacity, the existing analysis remains valid.

<u>Section 2.13.4.1.6, Startup of an Inactive Reactor Coolant Pump</u>

With less than 4 RCPs running the core is subcritical. The maximum temperature differentials between the steam generator and the primary system for which an inactive reactor coolant pump may be started are unchanged due to the increase in rated thermal power. Hence the existing discussion in the FSAR remains valid.

<u>Section 2.13.4.1.7, CEAW Modes 3, 4 and 5 ARI</u>

As discussed in FSAR Section 15.4.1.7, the withdrawal of a CEA adds reactivity to the reactor core causing the core power level to increase, as well as a time dependent redistribution of core power. The CPCs generate a reactor trip when the CPC bypass is automatically removed at 2.4*10-4% of rated thermal power. This trip causes the shutdown of the reactor prior to the point of adding sensible heat. The CPC bypass is unaffected by power uprate, thus the FSAR discussion remains valid.

Section 2.13.5.1.1, CVCS Malfunction

The FSAR discussion of this event is focused upon how long it would take for the pressurizer to fill due to the inadvertent actuation of additional charging pump capacity. The power uprate project changed neither charging pump capacity nor the permissible levels in which the pressurizer must be maintained. Therefore the analysis in the FSAR is not affected by the power uprate.

Section 2.13.5.1.2, Inadvertent ECCS Actuation

There is no change to the safety injection system as a result of the increase in rated thermal power. The FSAR discusses how the cutoff pressure of the safety injection system is below operating system pressures. Therefore the safety injection system would be incapable of actually discharging to the RCS even if an inadvertent actuation were to occur.

This assessment remains valid at the uprated conditions.

Section 2.13.5.2.1, CVCS Malfunction with Single Failure

The FSAR discussion of this event is focused upon how long it would take for the pressurizer to fill due to the inadvertent actuation of additional charging pump capacity. The power uprate project changed neither charging pump capacity nor the permissible levels in which the pressurizer must be maintained. Therefore the analysis in the FSAR is not affected by the power uprate.

Question 16:

CENPD-282-P-A, Technical Manual for the CENTS Code, is referenced in W3F1-2003-0074 (November 13, 2003). Since then, the NRC staff has reviewed and accepted WCAP-15996-P, Technical Description Manual for the CENTS Code (on December 1, 2003), which includes certain updates to the CENTS code. Does the version of the CENTS code that has been used in the non-LOCA analyses include any updates made since 1995? If so, then the updated CENTS technical manual should be cited.

Response 16:

To be provided in a later submittal.

Question 17:

Why is NUREG-75/087 (reference 2.13-14) cited, and not NUREG-0800.

Response 17:

To be provided in a later submittal.

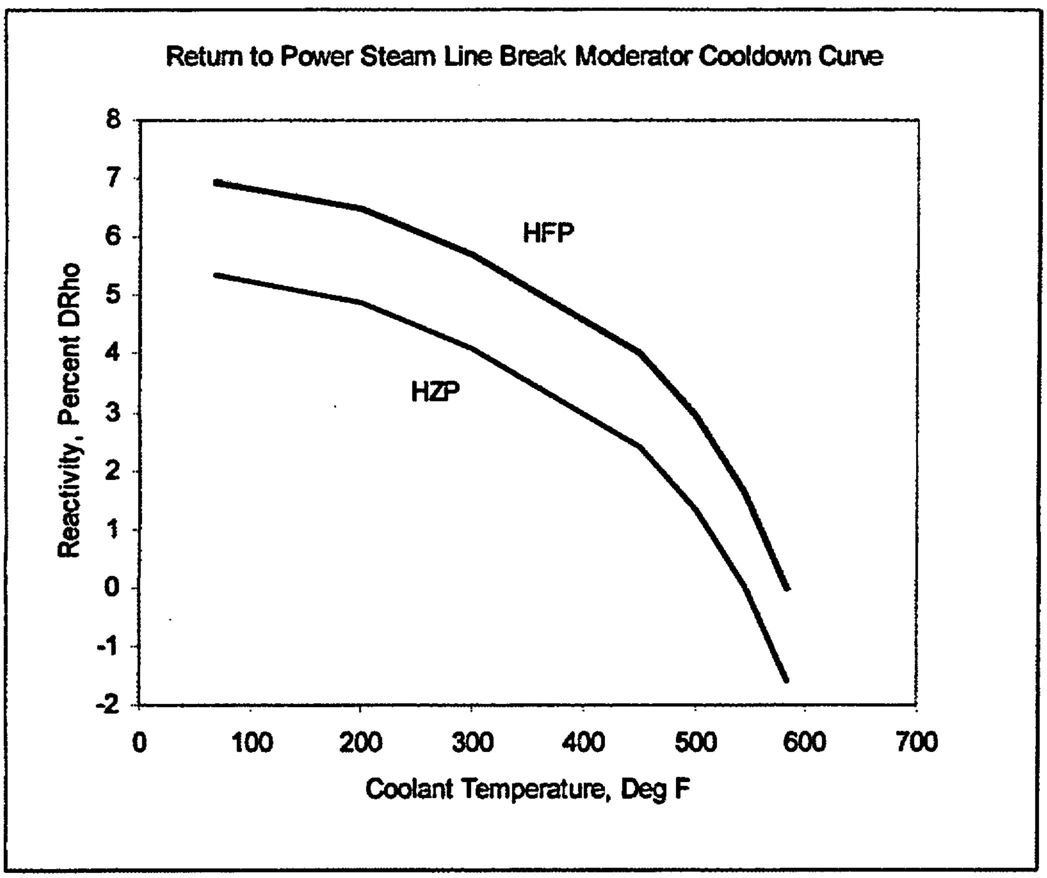
Question 18:

Where is Figure 2.13-1 (moderator cooldown curve)?

Response 18:

The moderator cooldown curves used in the Return-to-Power steam line break analysis are included below. This curve is generated based upon the most negative MTC in the N-1 CEA configuration. It represents the positive reactivity added to the core from both the increased moderation in the reactor coolant as well as the loss of CEA worth as the primary coolant increases in density during the cooldown.

Figure 2.13-1



Question 19:

Do the classes of moderate frequency incidents, infrequent incidents, and limiting faults correspond to condition II, III and IV events of ANSI N18.2? What are the acceptance criteria that are applied in the EPU analyses and evaluations for the classes of moderate frequency incidents, infrequent incidents, and limiting faults?

Response 19:

To be provided in a later submittal.

Question 20:

Please provide a tabulation to indicate that for each event, what specific acceptance criteria are satisfied, to demonstrate that the general acceptance criteria of the event's class are met?

Response 20:

To be provided in a later submittal.

Question 21:

For all events, in which a reactor trip is assumed to occur does the negative reactivity insertion account for the most reactive CEA being stuck in the fully withdrawn position?

Response21:

Yes. The value of negative reactivity inserted upon reactor trip is based upon the most reactive CEA being stuck in the fully withdrawn position.

Question 22:

In all analyses of post-trip thermal margin, especially in the steam line break (SLB) cases, is the minimum departure from nucleate boiling ratio (DNBR) calculated in the region of the assumed stuck CEA? How is that done?

Response 22:

To be provided in a later submittal.

Question 23:

In 2.13.0.2. Initial Conditions, it is noted that non-safety grade systems, that would act to mitigate a transient were not credited. Were any non-safety grade systems, that would act to aggravate a transient, credited?

Response 23:

In general yes, if the normal action of a control grade system will aggravate the results of the transient, then that action is modeled.

The modeling however is taken as being consistent with the plant being in a steady state initial condition. Therefore the analyses do not consider the situation of full pressurizer sprays as an initial condition as the plant would not be in a steady state at the initiation of the event.

If the normal action of the pressurizer pressure control system will aggravate the transient, then it is modeled. An example would be the pressurizer sprays, responding to the increasing pressure during CEA withdrawal events. The normal action of the pressurizer pressure control system in response to the increasing pressure will be to increase spray flow. This will delay the action of the high pressurizer pressure trip, allowing further increases in core power and RCS temperature. Thus, in this situation, normal modeling of this non-safety grade system is most adverse.

Question 24:

How is the decay heat determined and applied in the applicable analyses? What is the standard used?

Response 24:

To be provided in a later submittal.

Question 25:

Are all accident analyses and evaluations, presented in the application, cycle independent? Are all the accident analyses and evaluations that bound certain events of this application also cycle independent?

Response 25:

The physics and thermal hydraulic parameters used in the safety analyses in the application bound expected operating cycles at the new power level of 3716 MWt. The reload design process performs verification of the values used in the safety analyses. Should future reloads identify parameters that fall outside the bounds of the analyses in the application, cycle specific reload analyses will be performed to address the new values.

The plant configuration values used in the safety analyses in this application similarly represent the planned plant configuration for the uprated power condition. In support of the reload process, a groundrules document provides the setpoints, capacities, etc of plant equipment that can be both an initiator of transients or credited to mitigate transients. The reload process compares the values of these plant configuration parameters for the upcoming cycle against the values in the current safety analysis. Should future reloads identify parameters that fall outside the bounds of the analyses in the application, cycle specific reload analyses will be performed to address the new values.

Question 26:

For event analyses that bound event analyses of different categories (e.g., reactor coolant pump shaft seizure, a Limiting Fault event, bounds a partial loss of forced reactor coolant flow, an Infrequent event), please identify the specific results and criteria that are compared in order to reach the bounding conclusion.

Response 26:

To be provided in a later submittal.

Question 27:

Table 2.13.0-2 indicates that the lower limit of the pressurizer safety valve (PSV) setpoint is 2425 pounds per square absolute (psia). Table 2.13.0-3 indicates that the reactor protection system (RPS) analytical setpoint for high pressurizer pressure is 2422 psia. This RPS setpoint could be much higher considering instrument uncertainties. Please discuss the consequences of a potential lifting of the PSV prior to RPS actuation, which would prevent a reactor trip from occurring.

Response 27:

The credited high pressurizer pressure trip setpoint already includes the pressure measurement uncertainty applied in the direction to maximize the setpoint. The listed setpoint of the pressurizer safety valve includes the uncertainty applied to minimize the opening pressure. Therefore the pressurizer safety valve will not prevent the action of the high pressurizer pressure trip. Thus, the maximum value for RPS setpoint for high pressurizer pressure will be less than the lower limit for the Pressurizer Safety Valve setpoint.

Table RAI.27-1 presents the plant values of certain reactor protective system and engineered safety features actuation system setpoints compared to the values credited in the safety analyses. This table demonstrates the conservative application of uncertainties contained within the Waterford 3 extended power uprate analyses.

Table RAI.27-1

Protective Feature	LCO or Plant Value	Safety Analysis Range
High logarithmic power level trip	0.4% RTP	4.4% RTP
High pressurizer pressure trip	2350 PSIA	2422 PSIA
Low Pressurizer pressure trip	1684 PSIA	1560 PSIA
Low steam generator level trip	27.4% NR	5% NR
Low steam generator pressure trip	662 PSIA	576 PSIA
SIAS on Low pressurizer pressure	1684 PSIA	1560 PSIA
Steam generator differential pressure	123 PSID	230 PSID
MSIS on low steam generator pressure	662 PSIA	576 PSIA
EFW Control Valve	36.3% SG WR	21.3% SG WR
Pressurizer Safety Valve	2500 ± 1% PSIA	2500 ± 3% PSIA
Main Steam Safety Valves (1st valve)	1070 ± 1% PSIG	1070 ± 3% PSIG
EFW Lockout on Steam Generator Differential Pressure	123 PSID	230 PSID
EFW on Low Steam Generator Level	27.4% NR	5% NR

Question 28:

The steam generator tube rupture (SGTR) analysis which assumed that a loss-of-offsite power (LOOP) occurs three seconds following reactor trip is non-conservative for the radiological consequences. This assumption is not consistent with the current licensing basis at Waterford. Please provide the results of a SGTR analysis assuming a LOOP occurs at the events initiation.

Response 28:

To be provided in a later submittal.

Question 29:

For a SGTR accident, the most limiting single failure is to assume a stuck open ADV on the failed steam generator after it is automatically open following the event. Please explain why this assumption is not reflected in the sequence of event provided for this event.

Response 29:

To be provided in a later submittal.

Question 30:

Table 2.13.0-1 indicates that the pressurizer safety valve lift transient is categorized as a "limiting fault" and bounded by the SBLOCA. Standard Review Plan 15.6.1 categorizes this event as an event of moderate frequency with the acceptance criteria associated with an event with moderate frequency occurrence. Please provide the results of an analysis for this event at EPU conditions to demonstrate that these acceptance criteria are met. Based upon its frequency of occurrence during "more than 260 pressurizer safety valve years of operation", and the observation that it could only be caused by a passive mechanical failure, does operating experience support the classification of this event as a faulted condition? Provide a tabulation of the thermal design parameters and compare them to the values assumed in safety analyses to demonstrate that the safety analyses assumptions are conservative.

Response 30:

The inadvertent opening of a pressurizer safety valve, as an initiator, is classified as a limiting fault in Table 15.0-2 of the FSAR. The consequences of the event are examined in the spectrum of break sizes in the small break LOCA analysis.

The pressurizer pressure relief valves on CE digital plants consist only of passive spring loaded Pressurizer Safety Valves (PSVs). This is different from CE analog plants which contain both PSVs and Power Operated Relief Valves (PORVs).

For the analog plants, the PORVs are subject to opening as a result of a single failure in the control system. The inadvertent opening of a PORV is therefore included in the spectrum of anticipated operational occurrences for those plants.

PSVs are not subject to the same source of single failure. Therefore, they are not included in the spectrum of anticipated operational occurrences for CE digital plants. Section 15.3.5 of "RSB SER – CESSAR System 80, Docket No.50-470," October 17, 1981, contains a discussion of this on the System 80 docket. The conclusion that the analysis of PSV opening was adequately covered by the spectrum of breaks covered in the small break LOCA analysis is contained in that memorandum.

Question 31:

Consider the event where one or both pressurizer safety valves were to open during a moderate frequency event (e.g., loss of condenser vacuum), and then fail to reseat properly. If this failure rate were to be high enough, then the analysis of the moderate frequency event would have to account for the effects of an open pressurizer safety valve. What failure rate has been assumed for the proper reseating of pressurizer safety valves in the analyses of events.

Response 31:

To be provided in a later submittal.

Question 32:

Table 2.13.0-1 indicates that the Increased Steam Flow event (2.13.1.1.3) is analyzed as a moderate frequency event. The acceptance criteria, inter alia, specify that the resulting radiological dose must be less than or equal to a small fraction of 10 CFR 100 limits. Please quantify "small fraction". How does this radiological dose limit compare with the requirements of paragraph 20.1 of 10 CFR 20?

Response 32:

Traditional regulatory terminology is used in the power uprate report:

Small fraction of 10CFR100 is ≤ 10% of 10CFR100
(e.g. the acceptance limits for SLB without fuel failure but with an event generated iodine spike discussed in SRP Section 15.1.5, Main Steam Line Break)

Well within 10CFR100 is ≤ 25% of 10CFR100
(e.g. the acceptance limits discussed in SRP Section 15.7.4, Fuel Handling Accident)

Within 10CFR100 is ≤ 100% of 10CFR100

The SRP acceptance criteria for the safety analysis were based upon the results of the LPZ and EAB doses and specific fractions of the 10CFR100 limits. Discussion of occupational doses and normal operational releases in 10CFR20 is not specified in SRP acceptance criteria.

Question 33:

Section 2.13.1.1.3.1 states that any one of the following events may cause an increase in steam flow:

a) Inadvertent opening of the turbine admission valves. (approximately a 11% increase of the full power turbine flow rate)
b) Failure in the Steam Bypass System that could result in an opening of one steam bypass valve. (approximately 12.3% of the full power turbine flow rate)
c) Inadvertent opening of an ADV or SG safety valve. Each dump valve can release approximately 5.3% of the full-power steam flow, and the safety valve can pass approximately 9.3% of full power steam flow.

Failure of a steam bypass valve is declared to be the most adverse event. How has this determination been made? Were the reactivity effects of asymmetric core cooling, caused by the opening of one SG safety valve, considered?

Response 33:

To be provided in a later submittal.

Question 34:

Define RTP (rated thermal power) SLB (steam line break).

Response 34:

In this context, RTP stands for Return-to-Power. This describes an analysis in which the positive reactivity added to the core due to the steam line break cooldown is examined with respect to the core achieving increases in core power as it approaches critical conditions well after SCRAM during the event.

Question 35:

A major difference between the analysis results of the EPU SLB and the analysis results of the current SLB is that the DNBR SAFDL is violated (Tables 2.13.1.3.1-3 and 2.13.1.3.1-4). How is the extent of fuel pin failure (e.g. 2%) determined?

Response 35:

To be provided in a later submittal.

Question 36:

Why is loss-of-normal feedwater flow (Section 2.13.2.2.5), considered to be an Infrequent Event, and not a Moderate Frequency Event?

Response 36:

The Waterford 3 FSAR, Table 15.0-2, classifies this event as an infrequent event. Its classification in the PUR is consistent with the existing licensing basis. Other plants (for example San Onofre) also classify this event as an infrequent event.

Using the existing licensing classification is consistent with the Review Standard for Extended Power Uprates, RS-001, Rev 0, December, 2003.

Question 37:

Why is total loss-of-forced reactor coolant flow (Section 2.13.3.2.1), considered to be an Infrequent Event, and not a Moderate Frequency Event?

Response 37:

The Waterford 3 FSAR, Table 15.0-2, classifies this event as an infrequent event. Its classification in the PUR is consistent with the existing licensing basis. Other plants (for example San Onofre) also classify this event as an infrequent event.

Using the existing licensing classification is consistent with the Review Standard for Extended Power Uprates, RS-001, Rev 0, December, 2003.

Question 38:

Why is Inadvertent loading of a fuel assembly into an improper position (Section 2.13.4.3.1), considered to be a Limiting Fault, and not an Infrequent Event?

Response 38:

The Waterford 3 FSAR, Table 15.0-2, classifies this event as a limiting fault. Its classification in the PUR is consistent with the existing licensing basis. Other plants (for example San Onofre) also classify this event as a limiting fault event.

Using the existing licensing classification is consistent with the Review Standard for Extended Power Uprates, RS-001, Rev 0, December, 2003.

Question 39:

Why is SGTR (Section 2.13.6.3.2), considered to be a Limiting Fault, and not an Infrequent or Moderate Frequency Event?

Response 39:

The Waterford 3 FSAR, Table 15.0-2, classifies this event as a limiting fault. Its classification in the PUR is consistent with the existing licensing basis. Other plants (for example San Onofre) also classify this event as a limiting fault event.

Using the existing licensing classification is consistent with the Review Standard for Extended Power Uprates, RS-001, Rev 0, December, 2003.

Question 40:

Why is small primary line break outside containment (Section 2.13.6.3.1), considered to be a Limiting Fault, and not an Infrequent Event?

Response 40:

The Waterford 3 FSAR, Table 15.0-2, classifies this event as a limiting fault. Its classification in the PUR is consistent with the existing licensing basis. Other plants (for example San Onofre) also classify this event as a limiting fault event.

Using the existing licensing classification is consistent with the Review Standard for Extended Power Uprates, RS-001, Rev 0, December, 2003.

Question 41:

Section 2.6.1.3.1.1, Thermal Margin Analysis, indicates that the Modified Statistical Combination of Uncertainties (MSCU) methodology is applied in the analyses. The minimum DNBR SAFDL would be 1.26, as listed in the current Technical Specifications. However, the FSAR still refers to the prior DNBR SAFDL of 1.19 (e.g., in Section 15.3.1.1, Partial Loss of Reactor Coolant Flow). When Amendment No. 183 was issued, on March 29, 2002, the Safety Evaluation Report noted that the FSAR had not been updated, and advised the applicant to update the FSAR, in accordance to the requirements of 10 CFR 50.71. Please make the necessary updates to the FSAR. Please indicate the minimum DNBR SAFDL and the calculated minimum DNBR for all applicable accident analyses. Please verify that all events that are bounded by FSAR analyses, with respect to thermal margin, are comparable to FSAR analyses that applied the MSCU method.

Response 41:

To be provided in a later submittal.

Question 42:

Provide a quantified evaluation of the impacts of the EPU to a core power level of 3716 megawatts thermal (MWt) on the ability of Waterford 3 to cope with a Station Blackout (SBO) event. The evaluation should address the capacities of the condensate storage tank, turbine driven auxiliary feedwater pump, station batteries, and backup air supplies for air operated valves for decay heat removal and RCS cooldown during the time period of an SBO.

Response 42:

The SBO event is postulated for four hours without performing a Reactor Coolant System cooldown. At Waterford 3, the only power sources available during a SBO are the 125 volt DC onsite power system (i.e., safety related 1E batteries), steam from the steam generators (i.e., steam produced by the transfer of reactor core decay heat to the steam generator water inventory), and nitrogen gas accumulators (i.e., high pressure nitrogen gas sources used for operating vital control valves). The available power sources are used for operating equipment that 1) pump water into the steam generators, 2) control the flow of water into the steam generators, 3) control the flow of steam to the turbine-driven emergency feedwater pump, and 4) control the flow of excess steam from the steam generators to the environment. The impact of EPU on equipment used for these purposes and on the quantity of water available to remove decay heat is discussed below.

Condensate Storage Pool

At Waterford 3, the condensate storage pool is the safety-related water source used for feeding the steam generators during a loss of normal feedwater with the turbine or motor driven emergency feedwater pumps. The pool is a seismically qualified water source located in the reactor auxiliary building. The pool has a storage capacity of 210,630 gallons at the indicated level of 100%. Technical Specification 3/4.7.1.3 maintains an indicated water level in excess of the 170,000 gallons of water credited for the emergency feedwater system.

Condensate storage pool water inventory requirements for SBO pre-EPU are 80,000 gallons. The decay heat generated in the reactor core will increase due to the EPU, and the condensate storage pool water inventory needed for increased decay heat removal is calculated to be 82,200 gallons. This is based on maintaining hot standby conditions during the SBO and is well less than the Technical Specification minimum of 170,000 gallons dedicated for emergency feedwater system usage.

Turbine-Driven-Emergency Feedwater Pump

At Waterford 3, the turbine-driven emergency feedwater pump provides 100% of the water inventory needed to remove reactor core decay heat during a SBO. The pump is located in the reactor auxiliary building beneath the condensate storage pool, ensuring sufficient NPSH is available during operation.

The turbine is designed for cold start up and to run with steam generator pressures ranging from 1135 psig to 50 psig. The pump has a design capacity of 700 gpm (780 with minimum recirc) with a TDH of 1155 psi. Given an atmospheric dump valve set pressure of 992 psig for power uprate, the turbine-driven emergency feedwater pump can provide approximately 825 gpm to the two steam generators for decay heat removal. FSAR Section 10.4.9.2 requires the turbine-driven emergency feedwater pump to provide at least 575 gpm to the steam generator upon loss of feedwater flow in order to remove decay heat and to reduce RCS temperature and pressure to shutdown cooling entry conditions.

Class 1E Station Batteries

The 125VDC Distribution System is credited with providing safety related power to SSCs for up to 4 hours in response to a Station Blackout (SBO) event as the worst case loading event for the system. Plant calculations determined that a load conservatism (29 amps or more) was included in the SBO discharge capability analysis in addition to the required conservatism for aging, loading power factors and design margin.

Operation under EPU conditions does not place any new requirements on the 125VDC Distribution System. Additionally, no change in the capacity requirements or ratings for any of the associated components, such as load or stored electrical energy, is required to support operation under EPU conditions. Based on a review of plant calculations, power uprate will not have any effect on SBO requirements with respect to 125VDC Distribution System loading for the required coping period. Therefore, the 125VDC Distribution System remains capable of performing its required functions during SBO.

Nitrogen Accumulators

Compressed nitrogen, stored in accumulators, operate the essential emergency feedwater system isolation and flow control valves and the atmospheric dump valves during a station blackout. For secondary pressure controls and changing water levels in the steam generators, the atmospheric dump valves and the emergency feedwater flow control valves will modulate as necessary.

The nitrogen accumulators for the feedwater control valves and atmospheric dump valves are sized to provide nitrogen at a pressure and volume that would operate the valves for a total of 10 hours following an SBO. Valve cycling, losses caused by bleeding from the pneumatic positioners (i.e., gas bleeding from the balancing beam orifice) and losses due to leakage from mechanical joints are included in the nitrogen volume stored in the accumulators. Since the accumulators are sized for maintaining valve operability for 10 hours, there is sufficient nitrogen volume and pressure to operate the valves during SBO under EPU conditions.

Question 43:

To support the results of the loss of normal feedwater transient, please provide the following information:

1. Discuss the need for a time delay of emergency feedwater (EFW) flow to steam generators while the plant is operated below 15% rated power.
2. The results of a loss of normal feedwater transient assuming that the EFW flow is delivered within one minute following the event to show the effect of overcooling at the beginning of the transient.
3. Discuss the provisions made in plant emergency operating procedures (EOPs) for controlling EFW at the beginning of the event to prevent excess cooldown during this event.
4. Discuss the phenomena involved that causes the RCS pressure to peak and then decrease prior to EFW flow being delivered to steam generators.

Response 43:

1. The analysis did not identify the need for a time delay for plant operation below 15% power. The analysis was performed to examine the maintenance of a secondary heat sink. The full power cases are more limiting for that evaluation due to the combination of lower initial liquid mass in the steam generators, and the higher heat load to be removed by that inventory.

2. Steam generator temperatures are being controlled by the action of the steam dump and bypass system. Per Waterford TRM Table 3.3-5, the maximum response time for EFW is 50.0 seconds if offsite power is available. Delivery of emergency feedwater without the 50 second delay would not result in plant overcooling. The cooling associated with the early delivery of EFW would still be significantly smaller than the event in Section 2.13.2.3.2 in which a large excess steam demand has followed the loss of feedwater.

Note that the loss of feedwater analysis is performed in an attempt to minimize secondary system inventory, the concern being loss of the heat sink, not an overcooling transient.

3. There is no need to control EFW flow to avoid overcooling. The decay heat produced by the core is more than sufficient to heat the incoming EFW to the saturation conditions at the pressures to which the steam dump and bypass system would be controlling.

4. The increase in pressure is due to the normal pressure increases in a heatup event and following a reactor trip. The decrease in pressure is due to the action of the MSSVs.

Question 44:

Please confirm that the event scenario of the SGTR thermal-hydraulic analysis is consistent with EOPs at Waterford 3.

Response 44:

To be provided in a later submittal.

Question 45:

Provide the results of a SGTR thermal-hydraulic analysis to demonstrate that the SG will not be overfilled by EFW flow during this event.

Response 45:

The operators will terminate EFW to the affected steam generator upon identifying it as the affected SG. Additionally, the operators are instructed to control level in the affected generator as necessary to ensure that level does not exceed 85% narrow range (94% wide range). The operators may also increase backflow from the secondary to the primary via pressure control actions on the primary system. These instructions in plant procedures will ensure that the affected steam generator will not overfill.

Question 46:

Please provide a tabulation of all computer codes and methodologies used in the re-analyses and indicate the staff approval status, any conditions and limitations on their use, and how the limitations are satisfied for application at Waterford 3.

Response 46:

Attachment 6 to Entergy letter W3F1-2003-0074 dated November 13, 2003 contains Extended Power Uprate (EPU) report Appendix 1, "Safety Evaluation Report Compliance." This appendix contains the requested information for computer codes and methodologies used in ECCS performance analyses and for non-LOCA transient analyses and approved by an NRC-issued SER.

The Appendix 1 Introduction identifies the computer codes and methodologies that support the LOCA and non-LOCA transient analyses performed for the EPU. The tables and text of the Introduction identify the tables in Section 1 of the Appendix that contain the following information for each code and methodology:

- The NRC Safety Evaluation Report (SER) that documents regulatory approval
- The SER limitations and constraints
- Statements indicating how each constraint or limitation is met

As an example, the first entry in Table A1 of the Introduction identifies CENPD -132 and its Supplements 1 through 4 as supporting the LBLOCA analysis. The right hand column of the table headed, "SER Compliance Table No.," refers to Tables 1, 2, 3, and 4 in Section 1 as the location of the SER compliance information for CENPD -132 and its Supplements 1 through 4.

Question 47.

Provide a tabulation of the thermal design parameters and compare them to the values assumed in safety analyses to demonstrate that the safety analyses assumptions are conservative.

Response 47:

Table RAI.47-1 shows a comparison between the nominal values of thermal design parameters from Table 2.13.0-2, limits enforced by plant LCOs (and equipment setpoints) and the values used as limits in the safety analysis. It is seen that the safety analysis bounds the range of plant values.

Table RAI.47-1

Thermal Design Parameter	Nominal Value	Parameter LCO or Plant Value	Safety Analysis Range
Rated Thermal Power	3716 MWth	3716 MWth	3735 MWth
Pressurizer Pressure	2250 PSIA	2125 – 2275 PSIA	2090 – 2310 PSIA
HFP Core Inlet Temperature	543 °F	536 – 549 °F	533 – 552 °F
HZP Core Inlet Temperature	541 °F	536 – 549 °F	533 – 552 °F
Minimum RCS Flow	162.8×10^6 Lbm/Hr (Nominal Value)	154.9×10^6 Lbm/Hr (COLSS Monitoring Limit)	148×10^6 Lbm/Hr
Maximum RCS Flow	162.8×10^6 Lbm/Hr (Nominal Value)	N/A	170.2×10^6 Lbm/Hr
Pressurizer Level	Program between plant values	26% - 62.5%	21% - 67.5%
Steam generator level	60% - 70% NR	60% - 70% NR	45% - 80% NR

Question 48:

Expand Table 2.13.0-2 to include all primary and secondary parameters used in the non-LOCA transients.

Response 48:

Table 2.13.0-2 was intended to document those important parameters and their ranges which are applicable to all of the transients analyzed in the safety analysis. Additional parameters applicable to a specific event are contained in the input assumptions table for the individual event. An example of this is inclusion of one pin radial peaking factor and CEA Reactivity Addition Rate in Table 2.13.4.1.2-1 for the bank CEA withdrawal from low power conditions.

Beyond the additional event specific parameters, the assumptions table for each event contains the values of the general parameter set which were used in the conservative case presented in the power uprate report. Note that in some instances, where an individual event was insensitive to the value of a given parameter, an extreme value of an individual parameter might not have been used.

Question 49:

The reanalysis of the increased main steam flow transient assumes an initial pressurizer level at the upper limit of 67.5%. Please discuss the consequences if the lower limit of 21% is assumed in this analysis. Will the pressurizer be emptied much earlier in the sequence of event and cause loss of pressure control to RCS?

Response 49:

To be provided in a later submittal.

Question 50:

Tables 2.6-3 through 2.6-7 listed nuclear steam supply system design transients for Waterford 3. Please confirm that these design transients are applicable for the current core power level conditions and that they are unchanged for the EPU conditions.

Response 50:

The response of the plant to the design transients was evaluated for the Power Uprate Operating Point. Neither the list of design transients nor the number of cycles for a given transient were changed. The design transients and number of cycles listed in Tables 2.6-3 through 2.6-7 remain applicable for the EPU conditions.

Question 51:

Please confirm that only safety grade systems and components are credited in the reanalysis of all transients and accidents in your EPU report for Waterford 3.

Response 51:

Only safety grade systems and components are credited in the ECCS performance analyses and for mitigation of non-LOCA transients in Section 2.13 of the power uprate report for the Waterford 3 extended power uprate. Control systems are assumed where their normal operation will make the results worse as described in the response to Question 23.

Question 52:

Provide a more detailed rationale for your selection of initial plant conditions for each transient analyzed to achieve the most conservative results.

Response 52:

In general, the selection of the initial conditions attempts to do three things to make the consequences of a transient the most adverse. The first follows a process of attempting to aggravate the more important of the adverse physical effects that are going to occur during the transient. The second involves the selection of initial conditions that will delay protective actions of either the reactor protection system or the engineered safety features. The final major consideration in the selection of initial conditions for the transient is that the combination of the initial conditions should preserve the minimum amount of thermal margin that is going to be set aside in the plant LCOs during steady state operation.

The two sections below present examples of this process for two of the events in the extended power uprate report.

Return-to-Power Steam Line Break

Table RAI.52-1 follows this process for the return to power steam line break in determining the major initial condition assumptions. The sense of the parameters for the return to power steam line break is selected to maximize the chance for a return to criticality during the blowdown of the steam generator.

Table RAI.52-1

Parameter	Adverse Direction	Reason for Selection
Core Inlet Temperature	Higher	The positive reactivity from the moderator is driven by density increases as the primary coolant undergoes decreases in temperature. The rate of density increase is greater starting at higher temperatures. Therefore, the highest temperature allowed by the LCO's, with the uncertainty applied to further increase temperature, is selected as the initial condition.
RCS Pressure	Higher	The selection of a higher RCS pressure will delay the generation of a safety injection signal. Additionally, once safety injection begins, the higher pressure will minimize the amount of highly borated water added. Therefore the maximum RCS pressure permitted by the LCOs, accounting for uncertainties to further increase pressure, is selected as the initial condition.
SG Level	Higher	Maximizing the initial steam generator inventory will result in the greatest cooldown of the RCS once the uncontrolled blowdown begins. The initial condition is therefore taken at the high-level alarm point with uncertainties to further increase SG level.

Parameter	Adverse Direction	Reason for Selection
SCRAM worth	Lower	Crediting the minimum SCRAM worth maximizes the chances of the core returning to criticality. Therefore a minimum SCRAM worth, with the most reactive CEA assumed to be stuck in the fully withdrawn position, is assumed. Additionally, the moderator cooldown curve includes the positive reactivity addition effect of the loss of CEA worth as the moderator cools down from the initial temperatures.
Inverse Boron Worth	Higher	Higher inverse boron worth minimizes the negative reactivity added by the safety injection system once it begins to deliver borated water to the RCS.
MTC	More Negative	The cooldown of the moderator adds positive reactivity to the core. Therefore, the most negative MTC is used to maximize the positive reactivity added during the cooldown.
Delayed Neutron Fraction	Larger Fraction	The peak power obtained during the return to power steam line break is a result of increases in subcritical multiplication acting upon the neutron population in the core. A larger delayed neutron fraction will maximize the population remaining from the time that the core was critical, maximizing the return to power.
Doppler	More Negative	The fuel temperatures undergo reductions during the steam line break, initially due to the temperature reductions following trip from full power, and then continuing as further reductions in temperature occur during the cooldown following trip. Reductions in fuel temperature add more positive reactivity to the core. The selection of the most negative Doppler maximizes the insertion of positive reactivity from this source.

Pre-trip Steam Line Break

The second example of following the selection process is for the steam line break examination of the pre-trip power excursion. Table RAI.52-2 presents the selection and the reasoning for the parameters that make the pre-trip power excursion most adverse.

Table RAI.52-2

Parameter	Adverse Direction	Reason for Selection
Core Inlet Temperature	Higher	A higher initial RCS temperature is selected. Unlike the return to power steam line break in which the slope of the moderator reactivity density is of concern, for the pre-trip SLB, the higher initial temperature maximizes initial SG pressure. This higher pressure delays the occurrence of a low steam generator pressure trip. This will allow for the longest increase in core power prior to trip.
RCS Pressure	Higher	Unlike the return to power SLB in which the pressure was selected to delay safety injection, the pre-trip power excursion analysis selects the higher initial RCS pressure to delay the generation of a Low Pressurizer Pressure trip.
SCRAM worth	Lower	A lower SCRAM worth along with a reactivity insertion curve representative of a bottom peaked power distribution delays and minimizes the amount of negative reactivity which has been inserted into the core at any time during the trip sequences. This delays the power reduction and results in more adverse results.
Delayed Neutron Fraction	Smaller	Unlike the return to power steam line break in which the largest delayed neutron fraction was the most adverse, the pre-trip steam line break uses the smallest delayed neutron fraction. As the power is increasing due to positive reactivity addition before trip, a smaller delayed neutron fraction will result in the fastest power increase in response to the positive reactivity.
MTC	Most Negative	The pre-trip steam line break is also primarily driven by the positive reactivity added as the moderator cools down. For this reason, this event also uses the most negative MTC to maximize positive reactivity added during the cooldown.
Doppler	Least Negative	Unlike the return to power steam line break, in which the most negative Doppler adds positive reactivity during the cooldown of the fuel, the pre-trip steam line break experiences an increase in fuel temperature as the power in the core increases before trip. Minimizing the negative reactivity added by Doppler during the increase in core power will aggravate the power excursion.

As can be seen in the two examples above for the steam line break event, depending upon what is being examined, the pre-trip power excursion or the return to power, the sense of selection for each parameter may differ. Additionally, even when the events are selecting the same extreme of the parameter, it may be for different reasons.

Each event described in the power uprated report includes an input assumptions table. These tables present the results of following this logic process for the particular event.

Question 53:

Please discuss the significance of assuming an initial power of 1 MWt for the analysis of an inadvertent opening of a steam generator ADV.

Response 53:

To be provided in a later submittal.

Question 54:

To support the results of the reanalysis for the increased main steam flow with LOOP, and sheared shaft with LOOP, please provide the calculated amount of fuel pins with their minimum DNBR (MDNBR) below the allowable MDNBR of 1.26 in each event analyzed. Compare the amount of fuel failure with the acceptance criteria for these events.

Response 54:

To be provided in a later submittal.

Question 55:

To support the reanalysis of the main SLB accident with LOOP, please provide the following: 1) the calculated amount of fuel pins with their MDNBR below the allowable MDNBR of 1.26 for the cases with a break inside containment; and 2) transient curves for the cases with a break outside the containment.

Response 55:

To be provided in a later submittal.

Question 56:

For the loss of condenser vacuum transient, please provide the following: 1) the sequence of events for the peak primary pressure case and the peak secondary pressure case; and 2) a separate set of transient curves for each case analyzed.

Response 56:

The sequence of events for the peak primary system pressure case is contained in the power uprate report, Table 2.13.2.1.3-2. The figures showing the transient response of system parameters are contained in the power uprate report, Figures 2.13.2.1.3-1 through 2.13.2.1.3-14.

The sequence of events for the peak secondary system pressure case is included below as Table RAI.56-1. The transient response of plant parameters for the peak secondary pressure case is seen in Figures RAI.56-1 through RAI.56-14.

Table RAI.56-1
Sequence of Events for 3716 MWt Loss of Condenser Vacuum Peak Secondary Pressure Case

EPU Time (sec)	Event	EPU Setpoint / Value
0	Closure of turbine stop valves on turbine due to loss of condenser vacuum	--
7.2	Steam generator safety valve begin opening, psia	1117
9.2	High Pressurizer Pressure Trip Condition, psia	2422
10.7	CEA's begin to drop into core	--
12.5	Maximum pressurizer pressure	2576
12.6	Pressurizer safety valves begin to open, psia	2575
12.6	Maximum RCS pressure, psia	2633
14.3	Maximum pressurizer liquid volume	593
15.0	Pressurizer safety valves closed, psia	2446
16.3	Maximum steam generator pressure, psia	1175

Figure RAI-56-1
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Core Power vs. Time

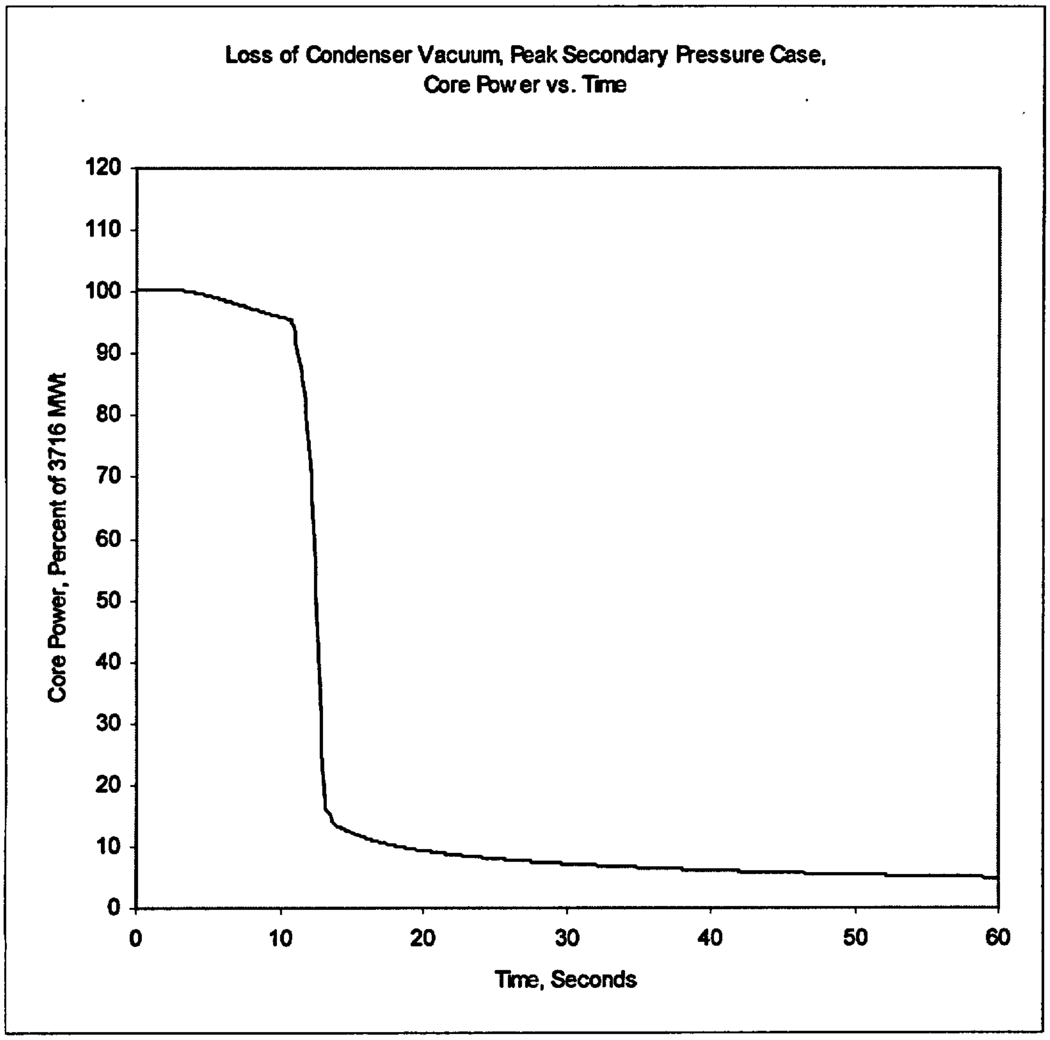


Figure RAI-56-2
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Core Heat Flux vs. Time

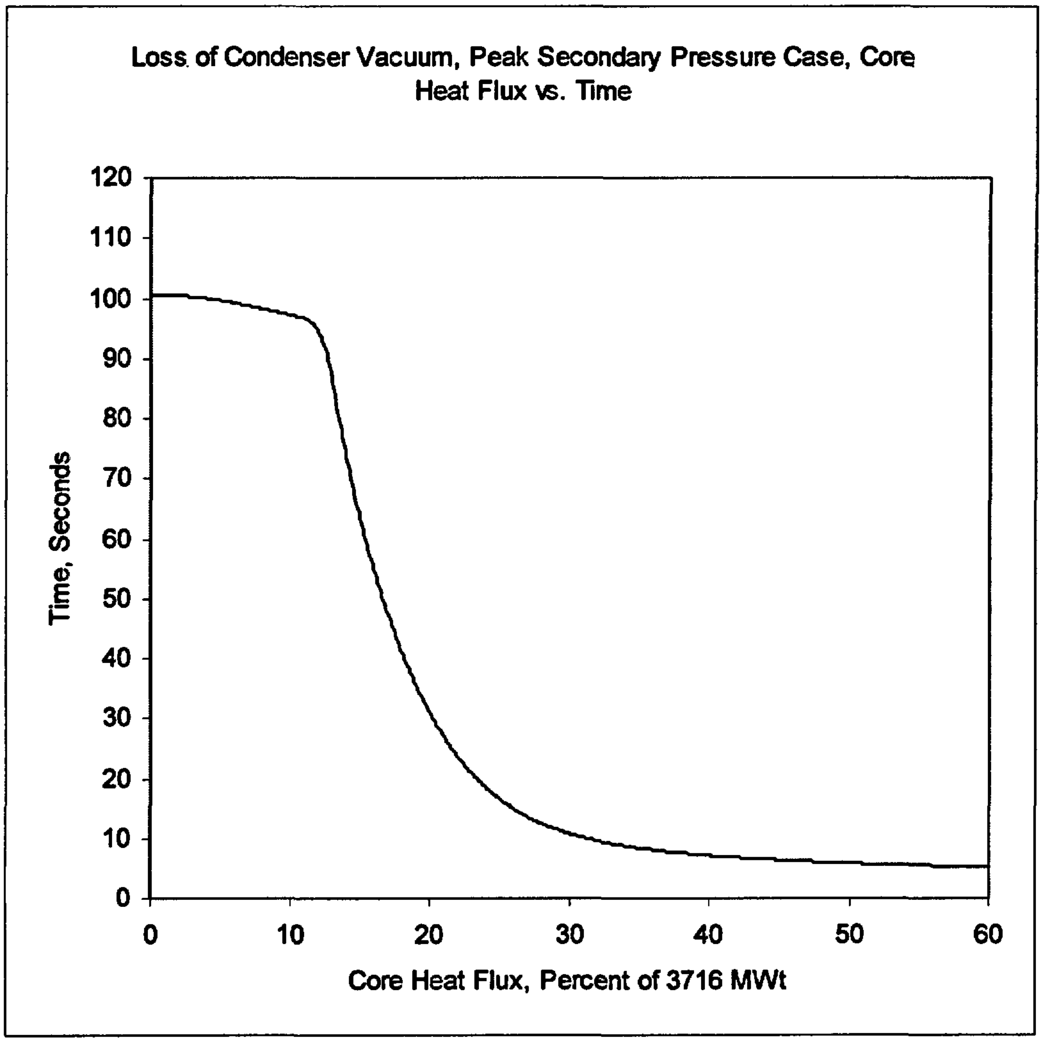


Figure RAI-56-3
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Pressurizer Pressure vs. Time

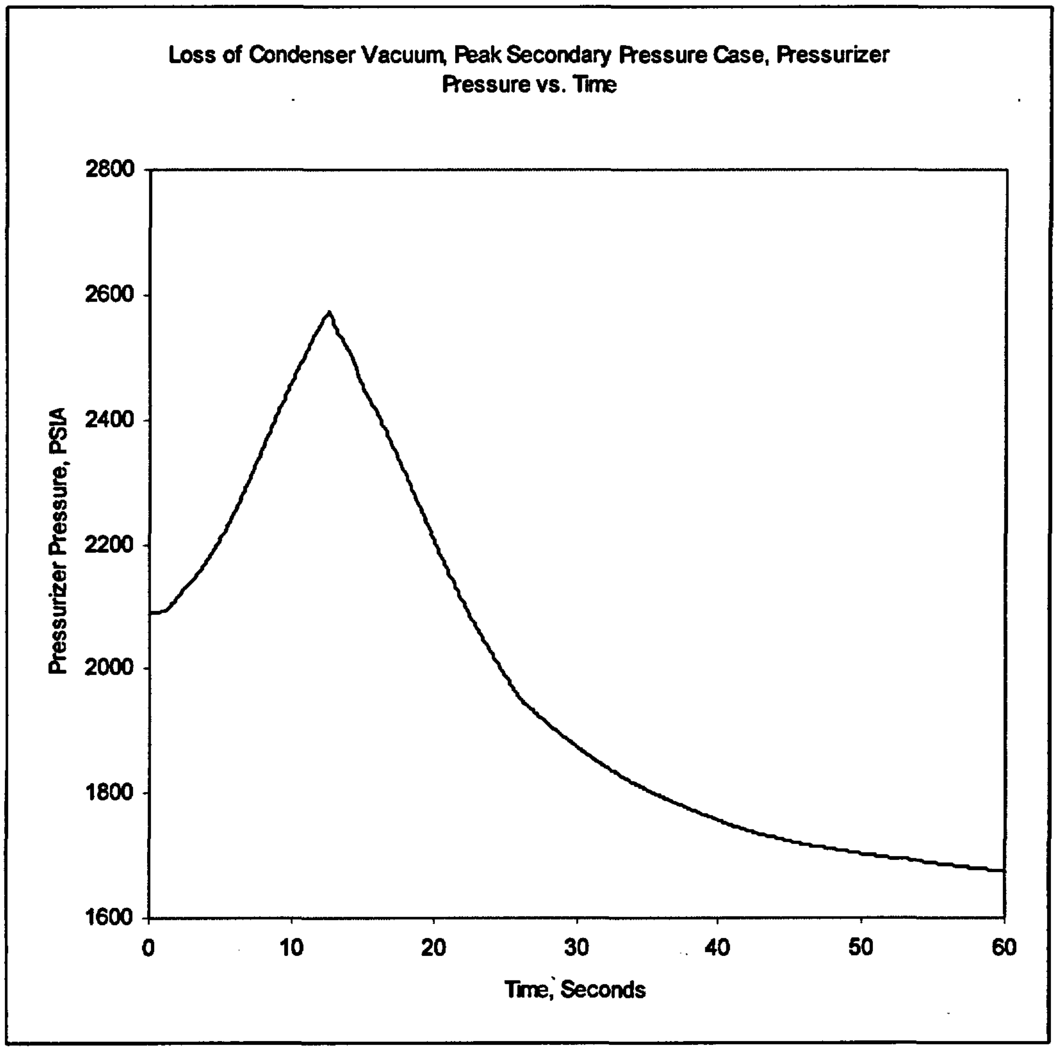


Figure RAI-56-4
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
RCS Pressure vs. Time

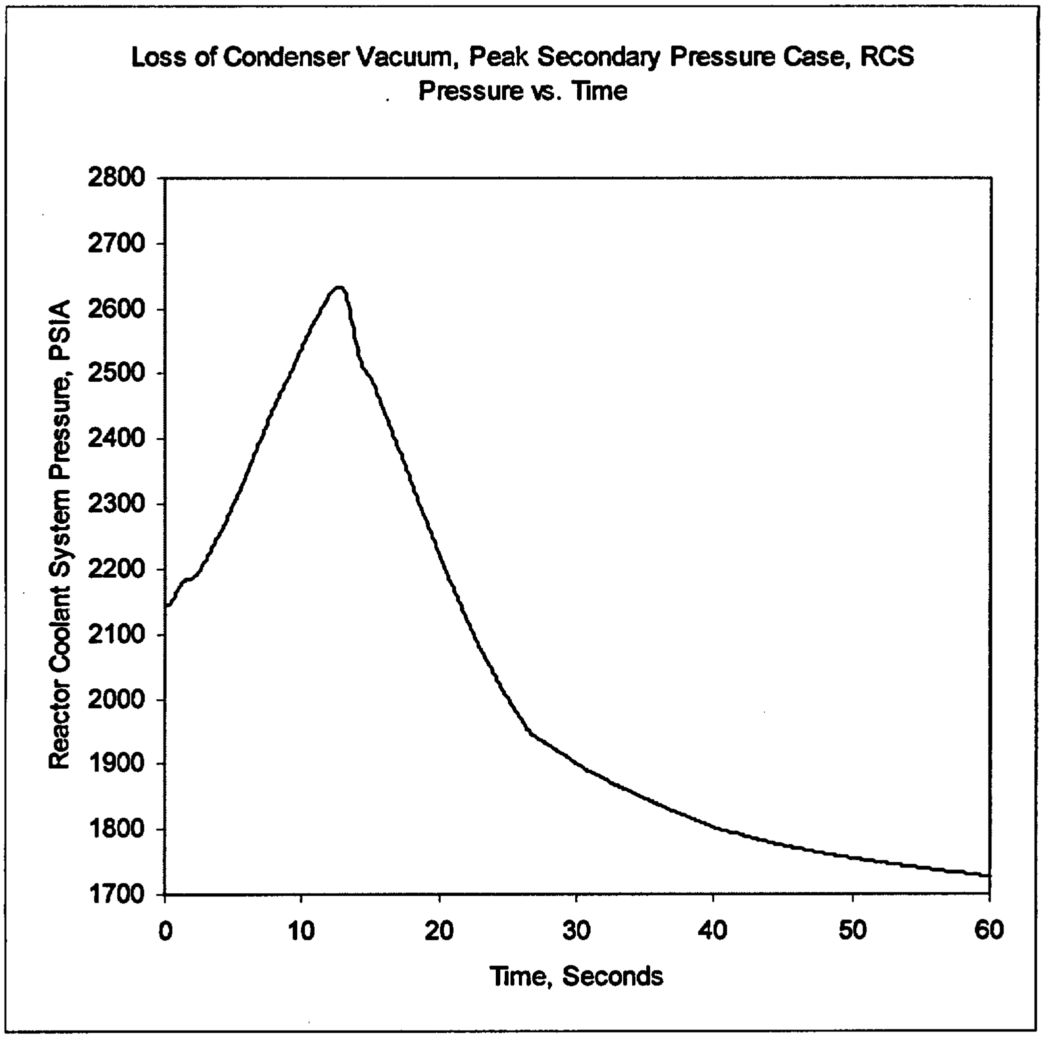


Figure RAI-56-5
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
RCS Temperatures vs. Time

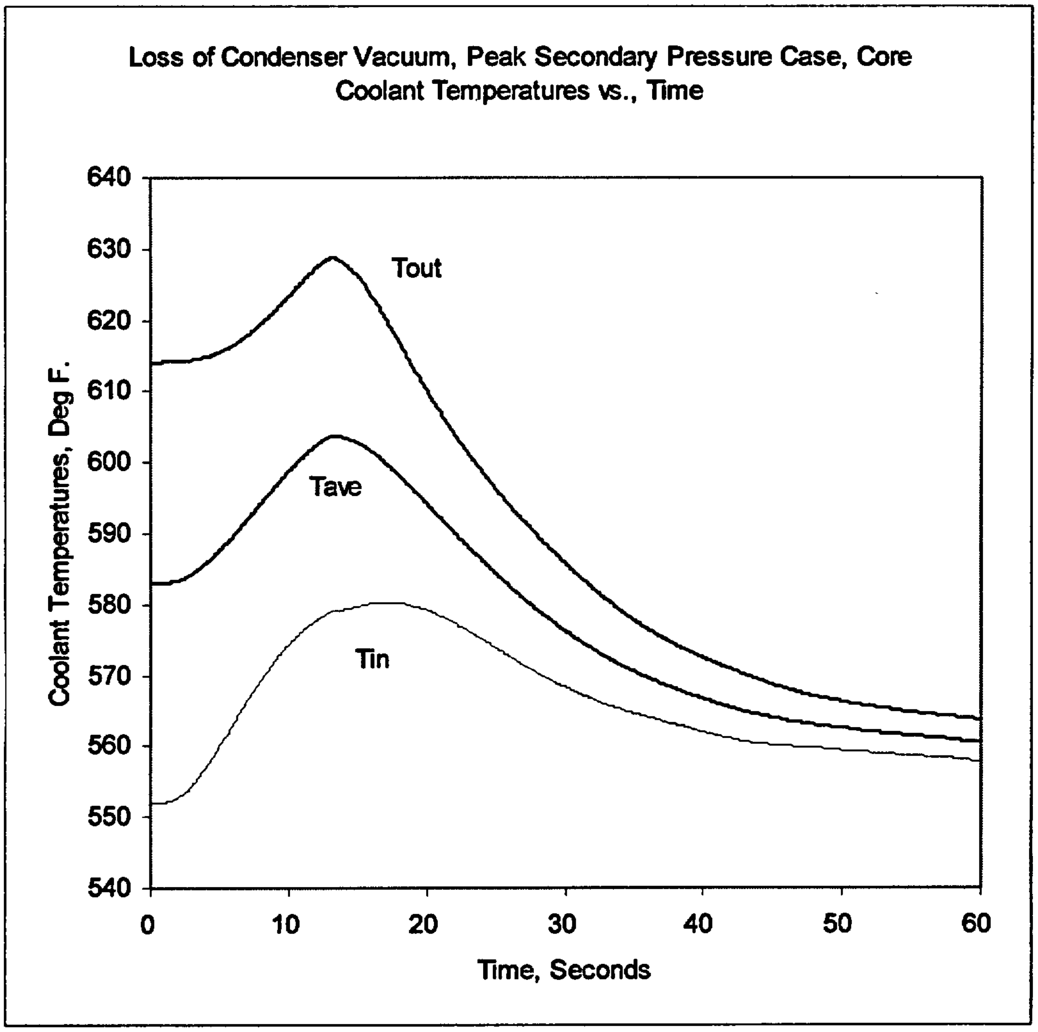


Figure RAI-56-6
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Pressurizer Volume vs. Time

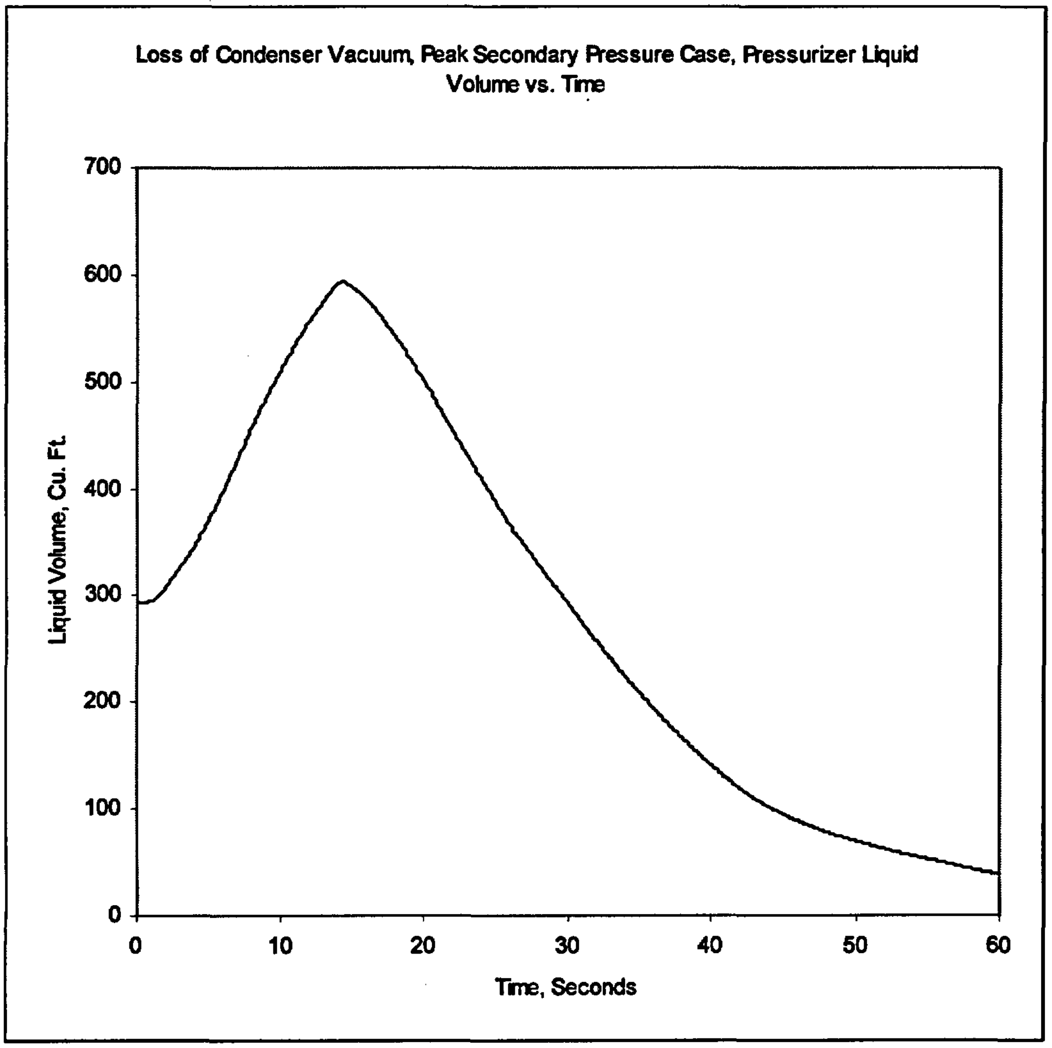


Figure RAI-56-7
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Steam Generator Pressure vs. Time

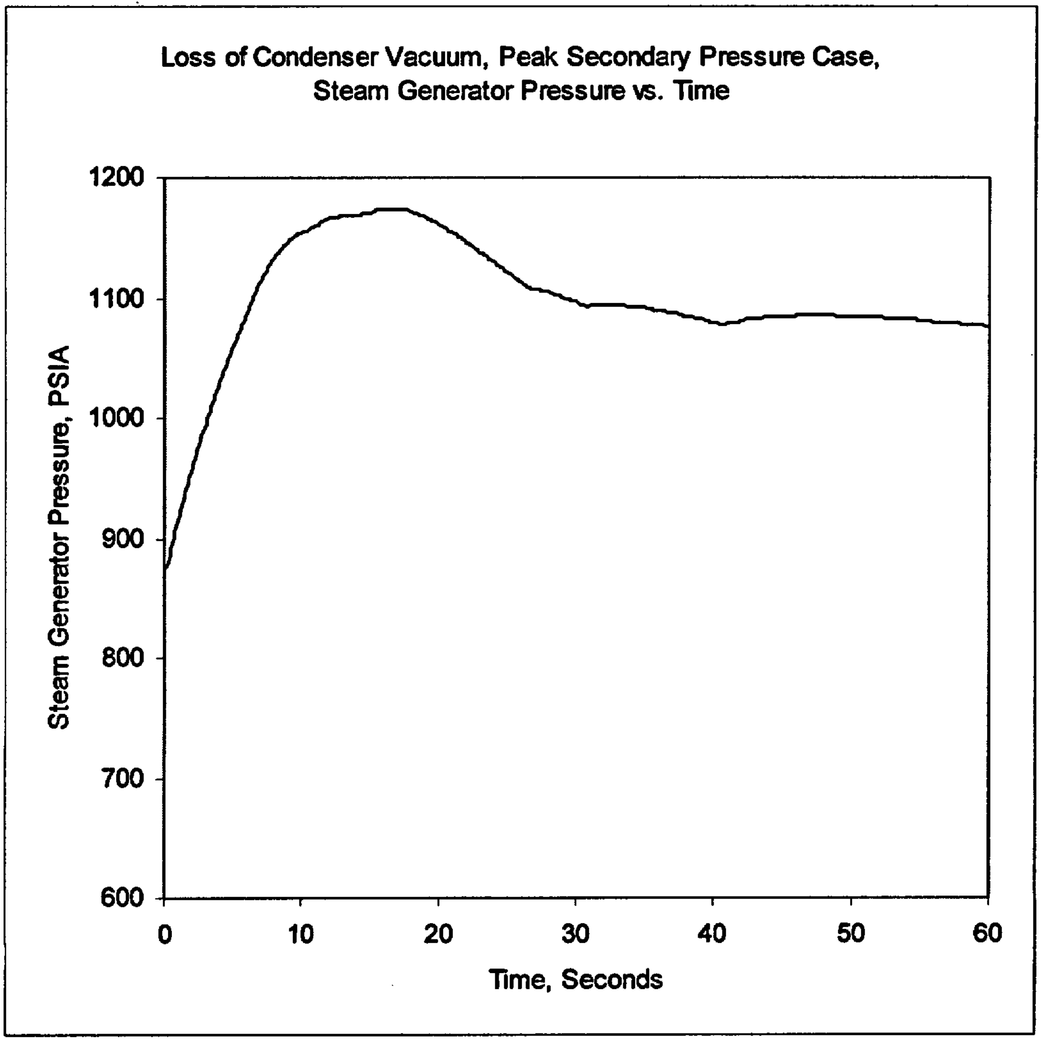


Figure RAI-56-8
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Steam Flow vs. Time

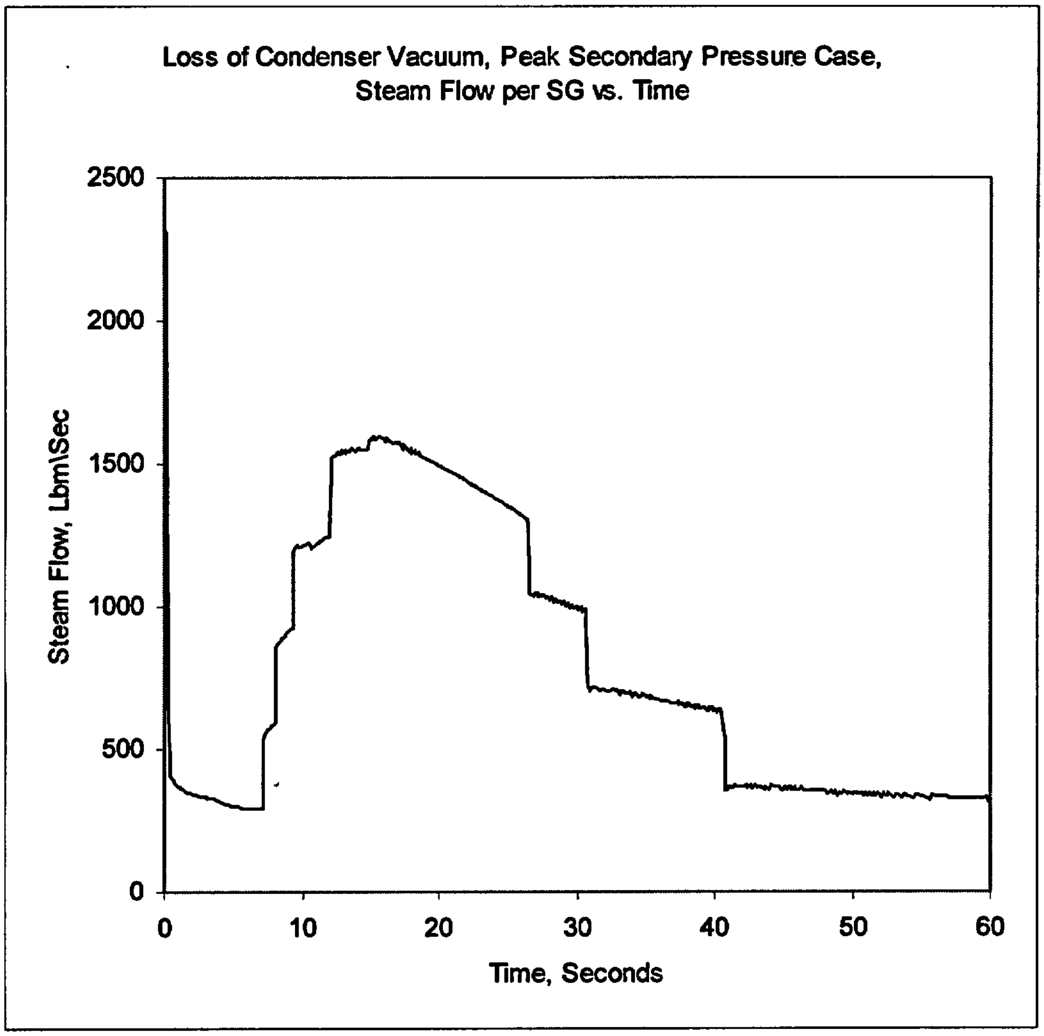


Figure RAI-56-9
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Feedwater Flow vs. Time

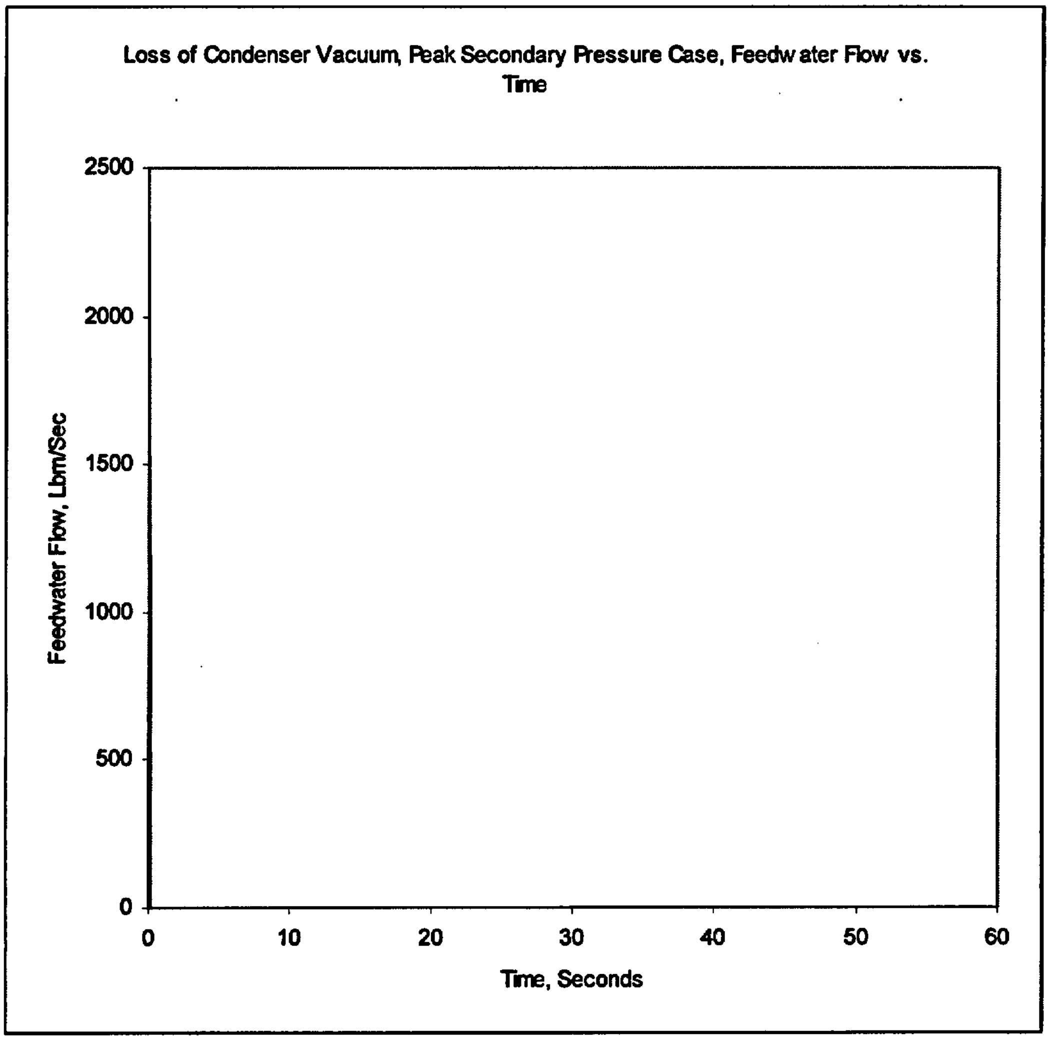


Figure RAI-56-10
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Feedwater Enthalpy vs. Time

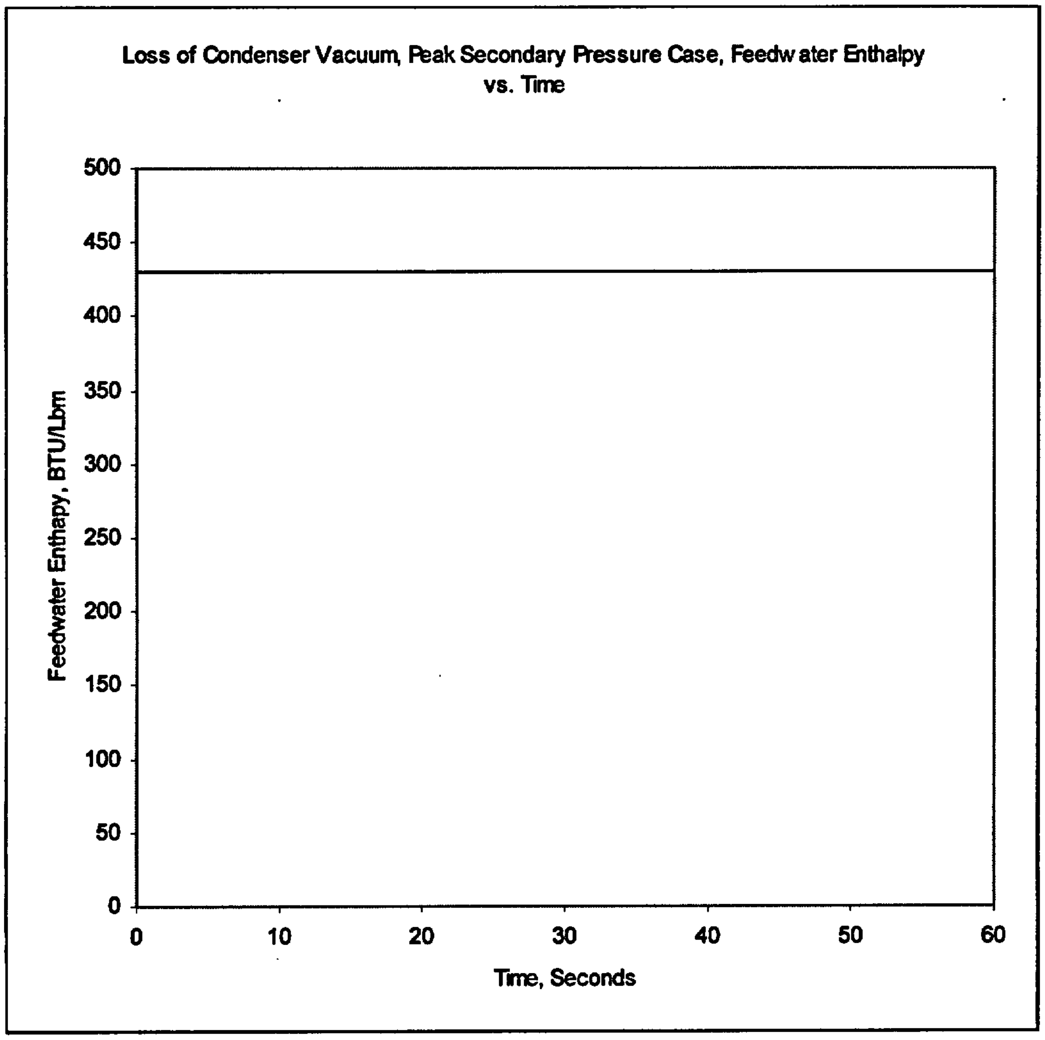


Figure RAI-56-11
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Steam Generator Liquid Mass vs. Time

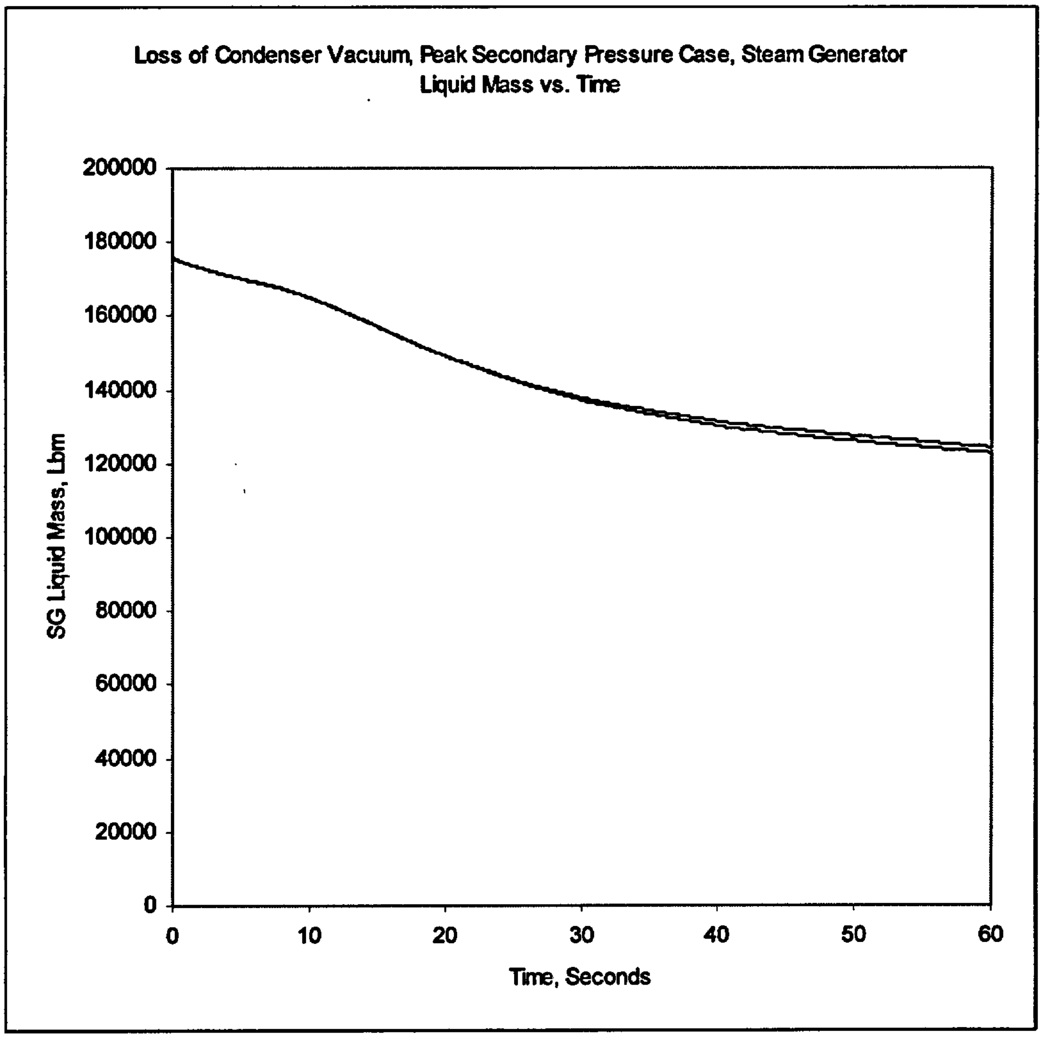


Figure RAI-56-12
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Pressurizer Safety Valve Flow vs. Time

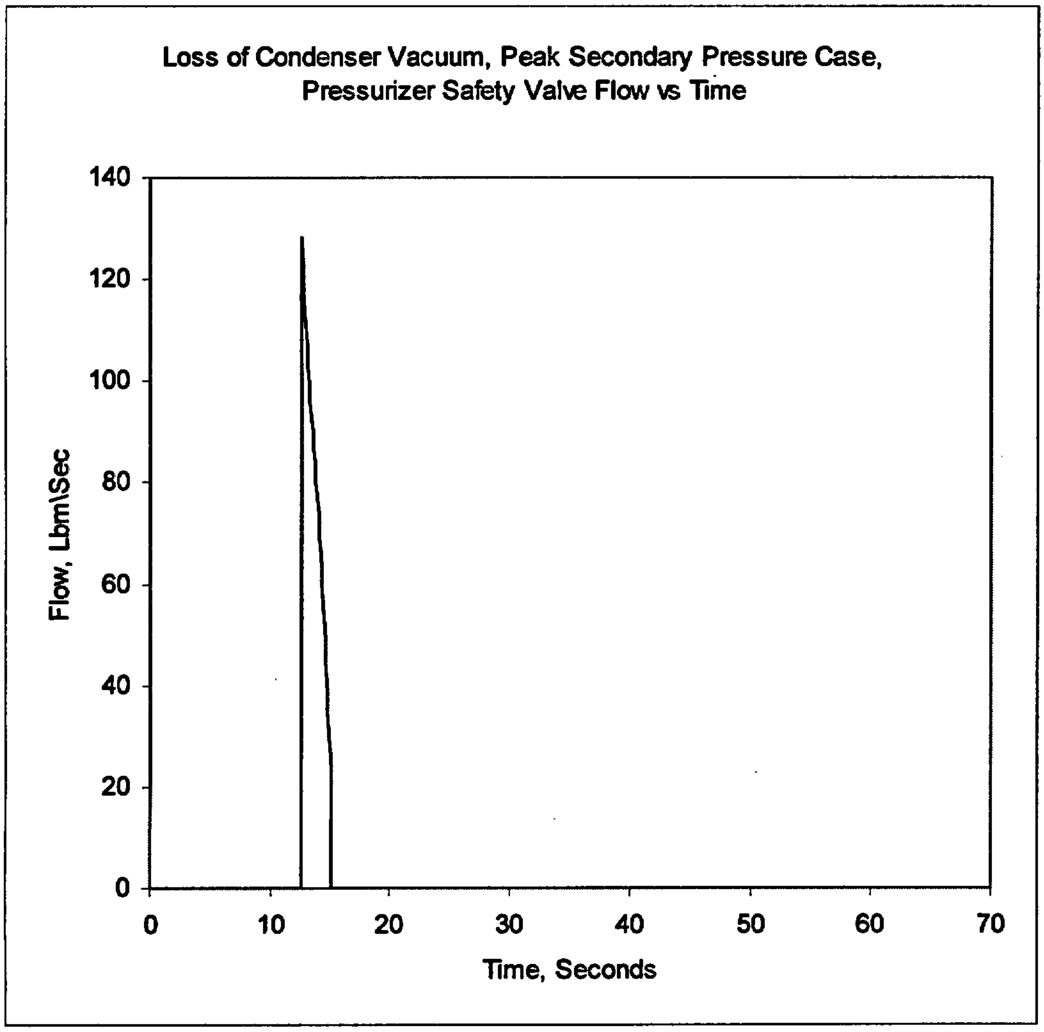


Figure RAI-56-13
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
Steam Generator Safety Valve vs. Time

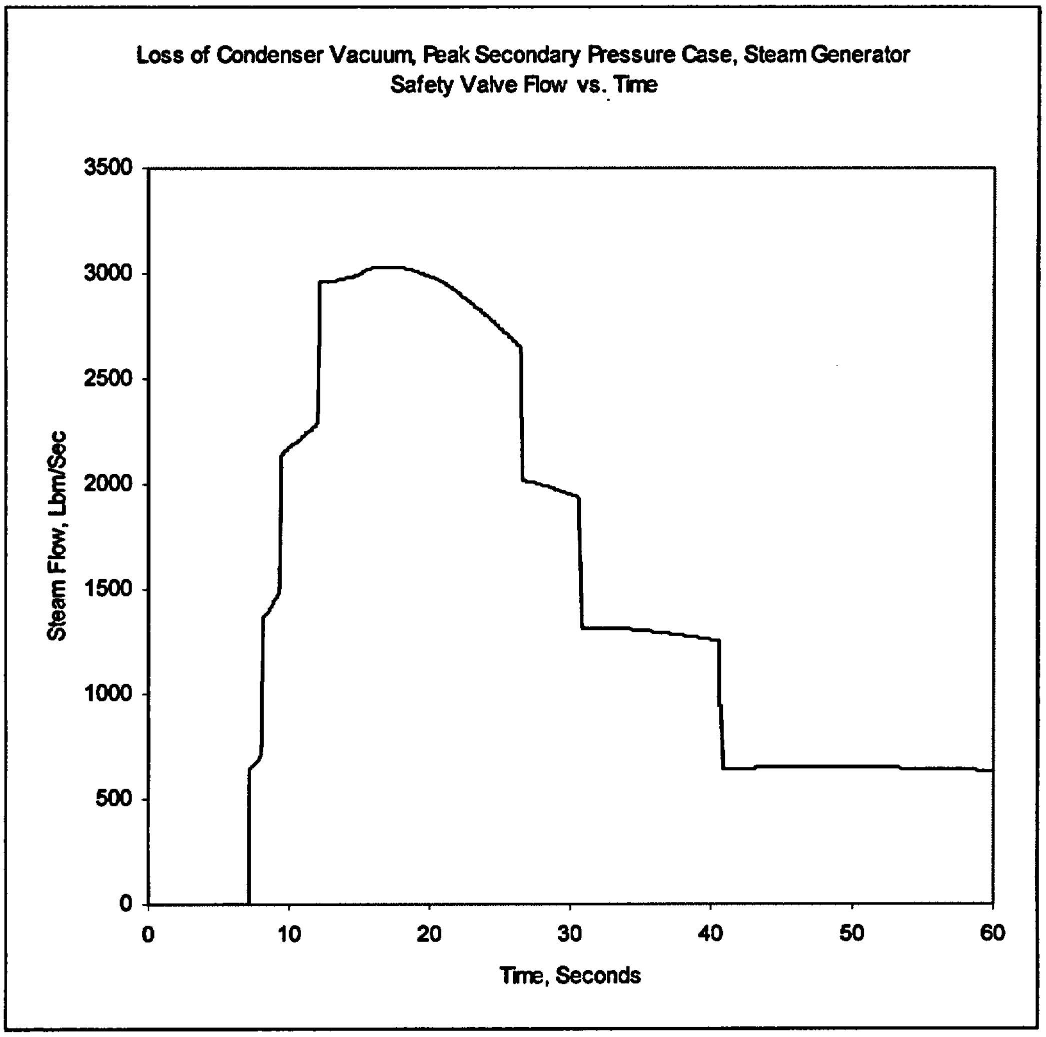
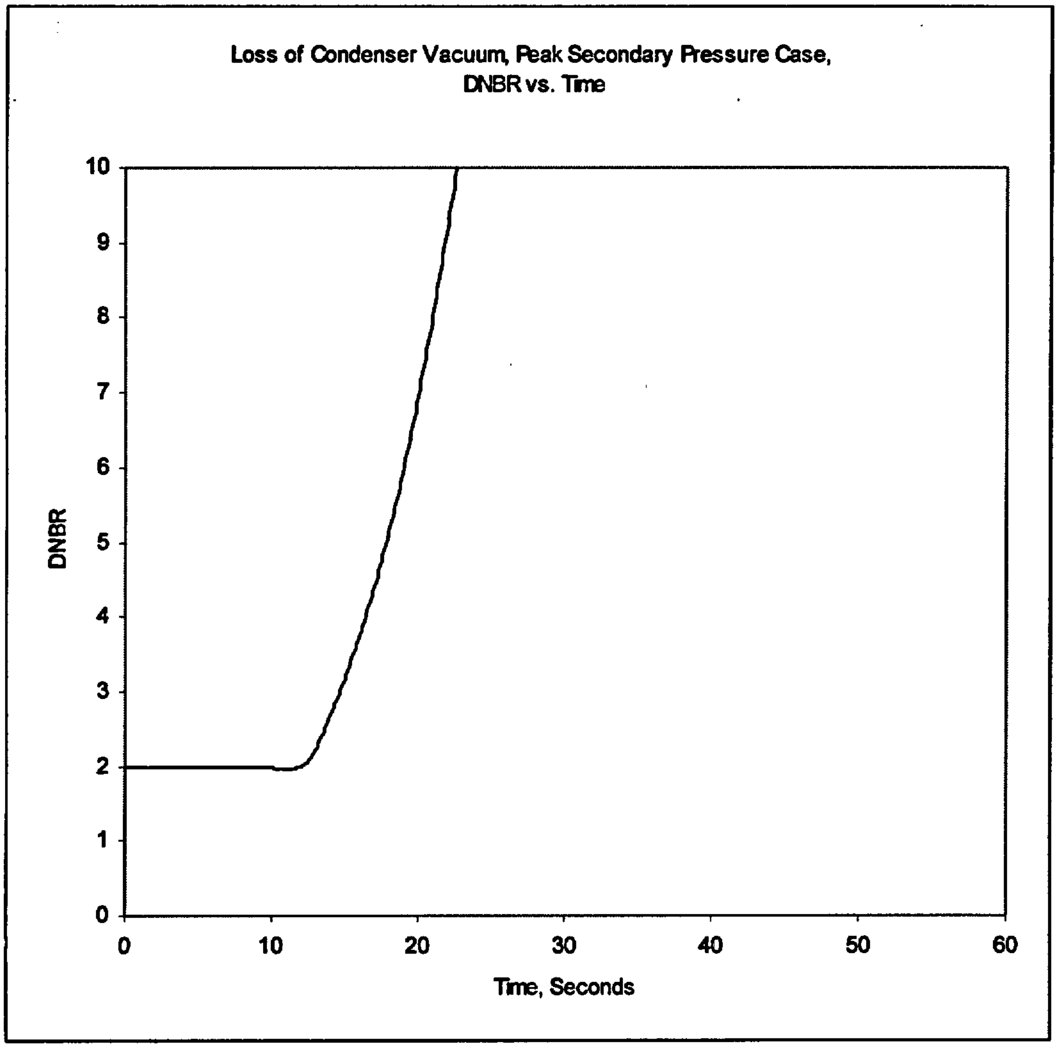


Figure RAI-56-14
Loss of Condenser Vacuum, Peak Secondary System Pressure Case
DNBR vs. Time



Question 57:

Discuss why the assumed break sizes for a main feedwater line break (MFLB) accident is different from that in the current licensing analyses. Provide a discussion of the break size assumed for a large MFLB relative to the double-ended break of a main feedwater pipe.

Response 57:

To be provided in a later submittal.

Question 58:

The proposed TS 4.7.1.5.a (surveillance requirements) will change the full closure time of the main steam isolation valve (MSIV) from 4.0 seconds to the analysis value of 8.0 seconds which includes an assumed 1.0 second instrument response time. It is stated in your submittal that a closure time of 4.0 seconds, measured under static test conditions, demonstrates closure under plant operating conditions within the 8.0 seconds assumed in the safety analysis. Please provide the following information: 1) explain how this surveillance requirement could be performed under plant operating conditions assumed in the safety analysis including the instrument response time for the required 8 seconds closure time; and 2) explain why a 4.0 seconds closure time under static test conditions demonstrates closure under plant operating conditions within the 8.0 seconds assumed in the safety analysis.

Response 58:

Note, as discussed in Attachment 1 of W3F1-2003-0074, that no change is being made for EPU to the closure time criteria assumed in the safety analyses.

1) The limiting condition requiring rapid MSIV closure is the Main Steam Line Break (MSLB) at full power to ensure 1) the positive reactivity effects are minimized associated with the steam generator blowdown and 2) the mass and energy released into containment remain within the assumptions given in the safety analysis. To fully demonstrate the MSIV will close for this limiting condition, an MSIV closure test would have to be performed at full power. Closing the MSIVs at full power would interrupt steam flow from the associated steam generator resulting in an unnecessary plant transient and a plant trip. Therefore, an alternative test is performed at cold shutdown conditions to demonstrate the MSIV will perform its required rapid closure function following a MSLB.

2.) The MSIVs are 40 in. vertical gate valves. The MSIVs are operated by a piston operator with nitrogen gas in the upper cylinder and hydraulic fluid in the lower cylinder. Each MSIV is opened or closed by controlling the hydraulic fluid flow into the operator's lower cylinder. To open the MSIV, hydraulic fluid is pumped from the MSIV reservoir skid into the operator's lower cylinder. This causes the piston operator to rise compressing the nitrogen gas in the operator's upper cylinder. To close the MSIV, dump valves are opened causing the nitrogen gas in the operator's upper cylinder to expand forcing the hydraulic fluid from the operator's lower cylinder back to the MSIV reservoir skid. There are two dump valves on each MSIV, each operated by solenoid valves from a redundant power channel. On receipt of a Main Steam Isolation Signal (MSIS), the solenoid valves energize causing the dump valves to open which rapidly closes the MSIV. If a single failure leading to a loss of a dump valve occurs (i.e., loss of a DC bus) following an MSIS, the redundant channel would ensure the MSIV closes to fulfill its function. These dump valves must be closed to allow opening of the MSIV.

   The surveillance requirement given in Technical Specification 4.7.1.5 to verify MSIV full closure is performed during cold shutdown conditions. A test ESFAS signal from each power channel is provided to the MSIV to ensure that MSIV full closure can be obtained using each dump valve. The MSIV closure time analysis demonstrates that if the actuator closes the valve within 4.0 seconds or less during cold shutdown (i.e, static) conditions, as required by current Technical Specification 4.7.1.5, then the actuator will fully close the

MSIV during accident conditions within 7 seconds or less. The correlation from the static stroke time results to the design basis accident is determined in the following manner.

The MSIV stroke time is calculated based on the flow rate of hydraulic fluid from the lower cylinder to the hydraulic system reservoir. Using fluid flow equations, the flow rate is equal to a system resistance constant times the square root of the hydraulic system differential pressure. The system resistance constant is the same for both the static and accident condition. The hydraulic system differential pressure is dependent on the operating conditions when the MSIV must close. The hydraulic system differential pressure is determined by calculating the force that acts to close the MSIV using a free body diagram. The components of the free body diagram are nitrogen pressure load, frictional loads, disk weight, stem rejection load, and the valve differential pressure load. A force balance is then used to determine the hydraulic pressure in the lower cylinder, which in turn is used to determine the hydraulic system differential pressure forcing fluid from the lower cylinder to the reservoir.

The safety analysis assumes MSIV full closure is achieved within 8 seconds. Assuming 1.0 second for MSIS actuation response time, a bounding system resistance constant for the hydraulic fluid flow rate is determined by the methodology given above. This accident condition closure time analysis assumes the minimum nitrogen pressure in the actuator's upper cylinder to ensure the limiting system resistance constant is utilized. Once this system resistance constant is known, the required closure time during a static test can be determined by assuming the static test operating conditions. For the static test, the closure time analysis assumes the maximum nitrogen pressure in the actuator's upper cylinder to ensure the most limiting (i.e. the fastest) required surveillance closure time will be obtained. If the MSIV closure stroke time were exceeded during surveillance, an inline valve that controls the hydraulic fluid flow back to the MSIV reservoir can be modified to increase the hydraulic fluid flow rate from the MSIV decreasing the closure stroke time.

The MSIS response time test is performed per Technical Specification Surveillance Requirement 4.3.2.3. The implementing test procedures ensure the combined instrument, trip bistable and matrix response time is less than 1.0 second.

Question 59:

The proposed TS 4.7.1.6.a (surveillance requirements) will change the full closure time of the main feedwater isolation valve (MFIV) from 5.0 seconds to 6.0 seconds to include an instrument response time of 1.0 second. Please explain how this surveillance requirement could be performed under plant operating conditions assumed in the safety analysis including the 1.0 second instrument response time for the total required 6.0 seconds closure time.

Response 59:

Note, as discussed in Attachment 1 of W3F1-2003-0074, that no change is being made for EPU to the closure time criteria assumed in the safety analyses.

Closure of the MFIVs effectively terminates the addition of main feedwater to an affected steam generator, limiting the mass and energy release for Main Steam Line Break (MSLB) or Feed Water Line Break (FWLB) inside containment, and reducing the cooldown effects for a MSLB. To fully demonstrate the MFIV will close for the mitigating function assumed in the safety analysis, an MFIV closure test would have to be performed at full power. Closing the MFIVs at full power would interrupt feed flow to the associated steam generator resulting in a loss steam generator level control and a plant trip. Therefore, an alternative test is performed at cold shutdown conditions to demonstrate the MFIV will perform its required rapid closure function following a MSLB or FWLB.

Question 60:

The proposed TS 3.7.1.1 specifies the maximum allowable power level with one or two main steam safety valves (MSSVs) inoperable. Please discuss why the maximum allowable power level with more than two inoperable MSSVs on any operating steam generator(s) are not specified in Table 3.7-2 of the proposed TS.

Response 60:

Technical Specification (TS) 3.7.1.1 currently only has provisions for one or two MSSVs inoperable therefore the EPU analysis was limited to one or two MSSVs inoperable. If three or more MSSVs are inoperable then TS 3.0.3 would be applicable.

Question 61:

It is stated that the maximum allowable power level with inoperable MSSVs were determined by the results of the loss of condenser vacuum transients. Please provide the resulting peak primary and secondary pressures for the cases with the current power level compared to that for the uprated power level.

Response 61:

To be provided in a later submittal.

Attachment 2 To

W3F1-2004-0061

Revised Commitment Regarding Reactor Vessel Internals Management

Revised Commitment Regarding Reactor Vessel Internals Management

In Entergy Operations, Inc. (Entergy) letter, "Supplement to Amendment Request NPF-38-249, Extended Power Uprate," dated May 26, 2004, Entergy made the following commitment.

> Entergy Operations, Inc. (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components (i.e., MRP Reactor Vessel Internals Issues Task Group (ITG)). Entergy commits to continue its active participation in this MRP initiative to determine appropriate reactor vessel internals degradation management programs.

Subsequent to the referenced letter Entergy and members of the NRC staff have discussed this commitment. Based on these discussions, Entergy revises the commitment to read as follows.

> Entergy Operations, Inc. (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components. Entergy commits to:
>
> - continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs,
> - evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to Waterford 3, and
> - incorporate the resulting reactor vessel internals inspections into the Waterford 3 augmented inspection plan as appropriate and provide the internals inspection plan to the NRC staff for information.

Attachment 3 To

W3F1-2004-0061

Additional Information Regarding EPU Dose Assessment

Additional Information Regarding EPU Dose Assessment

Question 1:

a. With regard to the east ADV, is this a single valve or series of valves? If the estimate is for a series of valves, is the distance input into the relative concentration (X/Q) estimate based upon the closest valve, an average, or some other criteria (e.g., mid-point)?
b. Is the ADV uncapped and vertically oriented? If uncapped and vertically oriented, what is the estimated minimum velocity and temperature of a postulated effluent release?
c. What is the estimated plume height based on the velocity of the steam being released from the ADVs?
d. How are the MSL distance inputs estimated? Is it based upon the minimum distance of any location along the steam line to the control room intake or on some other criteria?

Response 1:

a. Single Valves (one on East and West side of the reactor building wing area)
b. The atmospheric dump valves (ADVs) are uncapped and vertically oriented. No credit was taken for momentum effects for the ADV discharge.
c. Plume heights were calculated using Equations 11, 12, and 13 from Regulatory Guide 1.194. Heights were calculated for several of the steaming release scenarios considered in the calculations that support the dose calculations of letter W3F1-2004-0053 dated July 15, 2004. In all cases the results from Equation 11 were bounding. For dose calculations a release through 1 ADV results in the worst case control room dose since it assures that the worst case X/Q is applied to the entire release. However, for plume height calculations, releases through 2 ADVs is bounding since it minimizes the flow velocity through the ADVs. Both scenarios were reviewed as presented in the Table below.

RCP Status*	Off	Off	Off	Off	On
# of ADVs operating	2	2	1	1	1
Time (hrs)	2	8	2	8	8
Steam Gen. Temp	472.5 F	295 F	472.5 F	295 F	295 F
Steam Velocity (MPH)	23.38	15.05	46.76	30.10	39.80
RG 1.194 Eqn. 11 - Δh (m)	4.12	3.19	6.27	4.68	5.52
RG 1.194 Eqn. 12 - Δh (m)	35.61	32.86	44.87	41.40	45.44
RG 1.194 Eqn. 13 - Δh (m)	31.04	24.00	43.90	33.95	39.03
Total Release Ht. (m) **	6.2	5.2	8.3	6.3	5.5
Slant Path Determination (m)	9.0	8.4	10.6	9.4	10.0

Note *: RCP (Reactor Coolant Pump) status included since the RCPs add a significant additional heat load for steaming.

Note **: The "Total Release Height" accounts for the elevation difference between the ADV silencer (+80 ft.) and the air intake height (+73.33 ft).

d. A main steam line break outside containment and inside the main steam isolation valves (MSIVs) is a postulated design basis event. Steam would be released to the atmosphere from the failed main steam line. Since the MSIVs would isolate a main steam line break which could occur outboard of the MSIVs, a downstream break would result in significantly less radionuclides being released. The Waterford 3 main steam lines are located on the east and west sides of the reactor building wing areas. The closest point on the main steam lines is the elbow before the MSIV's which is assumed to be the break location. The steam release from the failed main steam line would be released through the missile protection grating at elevation 70.50'. These releases would travel across the roof of the reactor auxiliary building and to the control room intakes.

Additional Information Concerning the Use of the ARCON96 Code for the East ADV Release Point

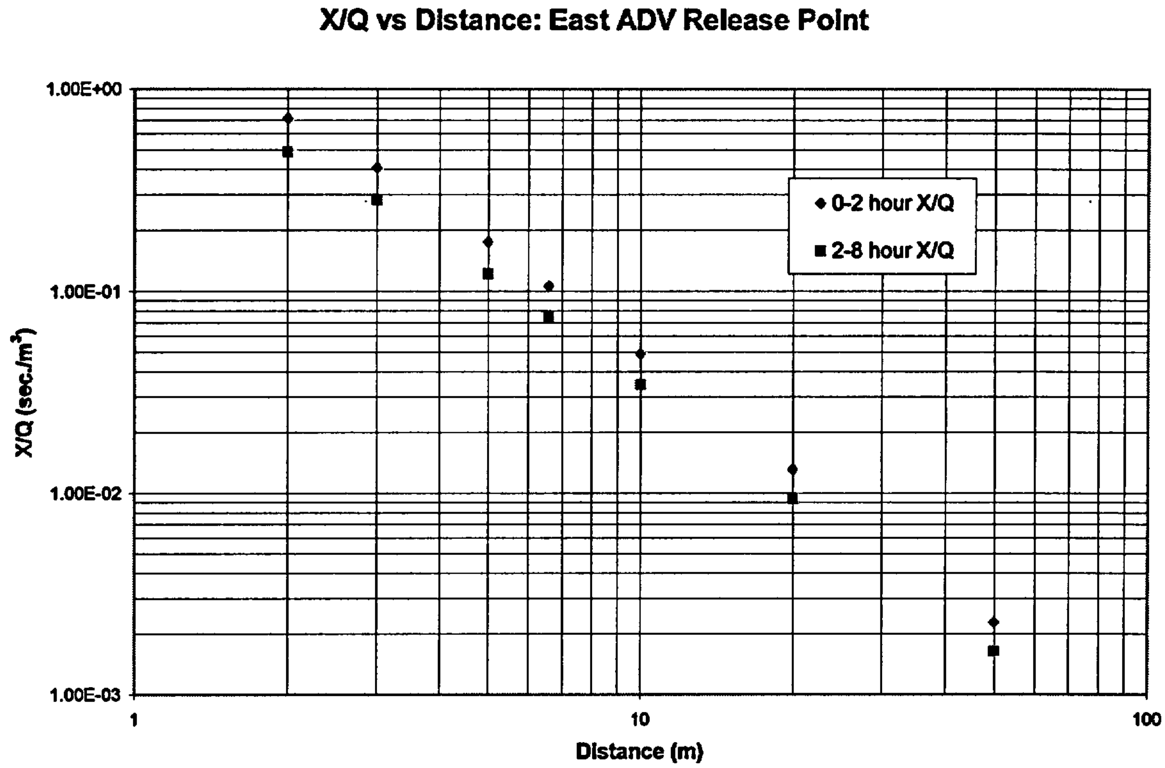
The Waterford 3 atmospheric dispersion factor for the East ADV to East Main Control Room air intake assumed a horizontal distance of 6.6 meters. The calculations were completed in May of 2003, and they used DG-1111 for guidance. The US NRC issued Regulatory Guide 1.194 in June of 2003. Both DG-1111 and RG 1.194 were consistent in that they stated that distances less than 10 meters should be addressed on a case by case basis. As such, Waterford 3 wishes to provide additional information concerning the East ADV X/Q model.

The ARCON96 code is documented in NUREG/CR-6331, "Atmospheric Relative Concentrations in Building Wakes," Revision 1. Section 3.2 of that document discusses the diffusion model used by the code. It states that the diffusion coefficients have the general form of

$$\sigma = ax^b + c$$

where x is the distance, in meters, and a, b, and c are parameters that are functions of stability. The parameters are defined for 3 distance ranges – 0 to 100 m, 100 – 1000 m, and > 1000 m. No limitation concerning 10 m was discussed or imposed in the ARCON96 manual. To further pursue this matter Waterford contacted Dr. Ramsdell of Pacific Northwest National Laboratory, the author of the ARCON96 code. He stated that there was "no mathematical reason" not to use the ARCON96 code for distances of less than 10 meters. Waterford also obtained and reviewed "Derivations of Continuous Functions for the Lateral and Vertical Atmospheric Dispersion Coefficients" (Reference 18 of Regulatory Guide 1.194) (Note that that document was based heavily on the work of Tadmer and Gur, which was the referenced basis of the ARCON96 code). No limitations are documented against using this information for distances less than 10 meters . As such, Waterford 3 was not able to obtain any information which would make the use of the ARCON96 suspect for this application.

It was previously communicated that the results of the east ADV model were compared with the results from the east MSSV (distance = 10.4 m), since the geometries were similar. Based on the results it was concluded that use of the ARCON96 was appropriate. Specifically, the ADV results were roughly 2.5x the results of the MSSV which seems very reasonable when engineering judgment is applied. To further research this claim, Waterford has performed additional sensitivity calculations using the east ADV model itself. The distance in this model was varied between 2 m and 50 m. The results of this sensitivity show that the calculated X/Q shows very predictable behavior over this range as demonstrated in the Figure below. It is not until distances of 1 m and below that the results become suspect for this specific model.



Note that RG 1.194 a factor of 5 reduction can be applied to X/Q's for uncapped, vertically oreinted release points for which the vertical velocity exceeds the 95th percentile wind speed by a factor of 5. The 95th percentile wind speed for Waterford 3 is 18.0 miles per hour (mph) for the 60 meter meteorological instrumentation (height above plant grade), and 13.3 mph for the 10 meter instrumentation. These values are comparable to the minimum average velocity for the ADV releases in the table above. While these releases do not meet the criteria for the factor of 5 reduction, the fact that the average velocity for ADV releases equals the 95th percentile wind speed indicates that some level of conservatism exists in the calculated X/Q's for releases from the ADV's.

During a conference call between Waterford 3 and the NRC on July 15, 2004, the NRC requested that a "virtual X/Q" be determined using the inverse of the steam flow rate from the ADV. The bounding ADV release (i.e., resulting in the lowest flow rate) occurs with flow through 2 ADVs, at 8 hours, and with no Reactor Coolant Pumps in operation. Under these conditions the calculated flow velocity out of the ADV silencers was 15.05 mph. Using the fact that the ADV silencer is roughly 56 inches in diameter (area = 17.1 ft^2), a volumetric flow rate and "virtual X/Q" can then be determined.

$$VFR({}^{m^3}\!/_s) = \left(15.05MPH \bullet 0.44704 {}^{m/s}\!/_{MPH}\right)\left(17.1ft^2 \bullet 0.0929 {}^{m^2}\!/_{ft^2}\right) = 10.69 {}^{m^3}\!/_s$$

$$\chi/Q({}^{s}\!/_{m^3}) = \frac{1}{VFR} = \frac{1}{10.69 {}^{m^3}\!/_s} = 0.094 {}^{s}\!/_{m^3}$$

This value is comparable to, and lower than, the 0 – 2 hour X/Q value of 0.106 s/m^3 calculated by ARCON96.

All of the information above provides justification that the model used for the east ADV is both reasonable and appropriate. There are several conservatisms in the dose analyses themselves which ensure that the overall doses are conservative. First and foremost, the bounding X/Q values for each time period were applied to all of the unfiltered inleakage term for the duration of the event. Realistically such inleakage would be the result of a number of locations, which would have much lower X/Q values than the value used in this analysis for unfiltered inleakage. In reality the east air intake has one of the lowest probabilities for unfiltered inleakage. In most cases the unfiltered inleakage term dominates control room dose calculations.

The conservatism in the X/Q values can also be demonstrated by consideration of the volumetric flow rates of the release and of the assumed intake to the control room. Specifically, it can be shown that the X/Q values computed for the ADV release point are conservative in that use of those values in conjunction with the intake flows to the control room may overconservatively predict more Curies entering the control room than is physically possible.

Consider the volumetric release rate from the ADV's. The worst case (minimum) steam velocity is 15.05 mph. That velocity is based on an average release over 15 minute intervals. This corresponds to a volumetric flow rate of:

Q_1 = 15.05 mph * (5280 ft/mile) * (1 hr/60 min) * 17.1 ft2 = 22,650 ft3/min.

The control room model assumptions differ slightly between the power uprate and Alternate Source Term submittals (Waterford 3 letter W3F1-2004-0053, dated July 15, 2005), where AST assumptions are bounding. For the time period late in the steaming release events for which this applies, the inflow to the specific control room intake consists only of the unfiltered inleakage (100 CFM assumed) which is assumed to be drawn into the control room. Pressurization flow is directed to the other intake by this time in the event, thus 100 CFM is the maximum intake to the limiting air intake. Because of the relative geometry, the other ADV has negligible contribution to the unfiltered inleakage and thus to dose. Worst case intake geometry (East ADV releasing to the East Main Control Room intake) is assumed. It is realistically assumed that the releases do not concentrate once released to the atmosphere. Thus, the maximum percentage of the radiological releases which can physically be transported to the control room is:

100 CFM / 22,650 CFM = 0.442%

The formula used to determine activity intake to the control room based on calculated X/Q values is:

$Ci_{INTAKE} = X/Q * Q_{intake}\ (CFM) * Ci_{RELEASE}$

For releases from the East ADV to the East Control Room intake, X/Q = 7.45E-02 s/m3 for the 2-8 hour period. Thus, this formula predicts that the percentage of the release which is transported to the control room is:

$$X/Q * Q_{intake} = 7.45E\text{-}02\ s/m^3 * 100\ CFM * (.3048\ m/ft)^3 * (1\ min/60\ sec) = 0.352\%$$

Thus, this would say that about three fourths of the volumetric intake to the control room comes from the ADV release, with only approximately one fourth due to dilution from ambient atmosphere. This is considered an overprediction of the intake to the control room from the release. Further, if it is assumed that all the steaming release is from a single ADV (as in the limiting Small Break LOCA control room dose calculation) the maximum amount (.221% = .442%/2) that can be physically transported to the control room is less than that predicted by the X/Q model.

This same logic can also be applied to show the conservatism of the X/Q values used for releases from the East ADV to the East Control Room air intake early in the event. Per the table under Item 1.c., release velocity would be 23.4 mph at the 2 hour point into an event based on both ADV's releasing (Note only one ADV is assumed to provide the release for the limiting Small Break LOCA dose analysis). For 2 ADVs at 2 hours, the corresponding volumetric flow rate is:

$$Q_1 = 23.4\ mph * (5280\ ft/mile) * (1\ hr/60\ min) * 17.1\ ft2 = 35{,}200\ ft3/min.$$

At this time in the event, the East air intake is assumed to be supplying the 225 CFM maximum of pressurization flow and to also be the location for the 100 CFM of unfiltered inleakage. Thus, the maximum percentage of radiological releases which can physically be transported to the control room is:

$$325\ CFM / 35{,}200\ CFM = 0.923\%$$

Using the formula for determining activity intake to the control room based on the calculated X/Q values, the predicted percentage of the release which would be transported to the control room is:

$$X/Q * Q_{intake} = 1.06E\text{-}01 * 325\ CFM * (.3048\ m/ft)^3 * (1\ min/60\ sec) = 1.63\%$$

Thus, this model predicts about 75% more activity is transported to the control room than is released from the ADV. This X/Q model is predicting more activity transport to the main control room than is physically possible. This demonstrates that the model is conservative.

Thus, the X/Q values calculated using ARCON96 are concluded to be very conservative. Use of these values results in more activity intake to the control room than would physically occur given relative flow rates of the release and the intake.
In summary,
1) there are no mathematic restrictions that impact the validity of the ARCON X/Q formulae at less than 10 meters
2) Conservatisms exist in the X/Q and radiological consequence modeling such that the application of the calculated X/Q's for Waterford 3 in those analyses is appropriate and conservative.

Question 2:

Is there no postulated release directly from the containment wall to the environment?

Response 2:

There is no postulated release from the containment wall to the environment. Waterford 3 has a primary containment surrounded by a shield building design with the annulus maintained at a negative pressure. Any activity entering the annulus from the primary containment would be held in the annulus before processing and release to the environment.

Question 3:

If the fuel handling accident relative concentration (X/Q) values were previously approved, please provide a reference citation.

Response 3:

The current X/Q data for offsite (EAB and LPZ) are documented in FSAR Table 2.3-136 and have not been modified since original licensing and approval by NRC. These values are presented in the FHA analysis of PUR Section 2.13.7.3.4. The current control room X/Q values for the fuel handling accident analysis were used in the analysis approved by NRC in support of License Amendments 169 and 176. These amendments were approved by the NRC in safety evaluations dated October 2, 2000, and November 21, 2001, respectively.

Attachment 4 To

W3F1-2004-0061

List of Regulatory Commitments

List of Regulatory Commitments

The following table identifies those actions committed to by Entergy in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

COMMITMENT	TYPE (Check one)		SCHEDULED COMPLETION DATE (If Required)
	ONE-TIME ACTION	CONTINUING COMPLIANCE	
Responses to the remainder of the questions will be provided by August 10, 2004.	X		8/10/04
The existing control loop will be modified such that the setpoint can be monitored on the plant monitoring computer. This connection to the non-safety related plant monitoring computer will meet applicable isolation requirements.	X		Implementation
Entergy Operations, Inc. (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components. Entergy commits to: • continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs, • evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to Waterford 3, and • incorporate the resulting reactor vessel internals inspections into the Waterford 3 augmented inspection plan as appropriate and provide the internals inspection plan to the NRC staff for information.		X (until reactor vessel internals inspection plans are incorporated into the augmented inspection plan and submitted to the NRC)	NA