Tennessee Valley Authority, Post Office Box 2000, Decatur, Alabama 35609-2000

October 16, 2000

10 CFR 50.55a(a)(3)(i)

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

Gentlemen:

In the Matter of	)	Docket No. 50-260
Tennessee Valley Authority	)	

BROWNS FERRY NUCLEAR PLANT (BFN) - UNIT 2 - PROPOSED RISK-INFORMED INSERVICE INSPECTION PROGRAM - RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (TAC NO. MA8873)

This letter responds to the NRC September 29, 2000, request for additional information regarding the proposed risk-informed inservice inspection (RI-ISI) program for BFN Unit 2. The BFN Unit 2 RI-ISI program was submitted to NRC by TVA letter dated June 1, 2000.

The BFN Unit 2 RI-ISI program is an alternative to current ASME Section XI inservice inspection requirements for Code Class 1, 2, and 3 piping. The BFN Unit 2 RI-ISI program also provides an alternative to the inspection requirements of Intergranular Stress Corrosion Cracking (IGSCC) Category "A" welds.

NRC's letter to TVA dated February 11, 2000, approved the BFN Unit 3 RI-ISI program. The same rules and principles that were used for the Unit 3 RI-ISI program were applied to the BFN Unit 2 RI-ISI program.

The enclosure to this letter lists the specific NRC requests for information, and the corresponding TVA responses.

A047

There are no new commitments contained in this letter. If you have any questions, please contact me at (256) 729-2636.

Sincerely,

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ENCLOSURE

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNIT 2

PROPOSED RISK INFORMED INSERVICE INSPECTION PROGRAM, RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION

Background

The proposed BFN Unit 2 RI-ISI program was submitted to NRC by letter dated June 1, 2000. The BFN Unit 2 RI-ISI program is an alternative to current ASME Section XI inservice inspection requirements for Code Class 1, 2, and 3 piping. The program also provides an alternative to the inspection requirements for Intergranular Stress Corrosion Cracking (IGSCC) Category "A" welds. TVA's program was developed in accordance with the Westinghouse Owners Group Topical Report WCAP-14572, Revision 1, as modified by the September 30, 1998, letter to the NRC from the Westinghouse Owners Group (with some deviations) and the guidance contained in GL 88-01.

NRC has previously approved the BFN Unit 3 RI-ISI program by letter to TVA dated February 11, 2000. The same rules and principles that were used to develop the Unit 3 RI-ISI program were applied to the BFN Unit 2 RI-ISI program. The physical design and plant layout of Units 2 and 3 are essentially identical. The BFN Unit 2 Residual Heat Removal (RHR) System has the cross-connect capability to both Units 1 and 3 while Unit 3 has cross-connect capability to Unit 2 only.

The BFN Unit 2 RI-ISI program analysis results in a risk neutral application, while the Unit 3 analysis results in a risk reduction. The differences in results are because: (1) the different pipe stresses and materials between the two units results in different failure rates; and (2) the difference in RHR cross-tie capability results in a different Core Damage Frequency between the units.

Pursuant to 10 CFR 50.55a(a)(3)(i) TVA has determined that the proposed BFN Unit 2 RI-ISI program alternative provides an acceptable level of quality and safety. TVA considers that quality is enhanced because the required inspections are specifically tailored to an identified failure mechanism and, where applicable, utilize existing programs with specified performance standards. The safety of the plant is unchanged. There is no impact on current safety margins from the implementation of this program.

Listed below are the specific NRC questions and the corresponding TVA responses. As a matter of policy, the NRC requests and the corresponding TVA responses were reviewed and concurred with by the Expert Panel on October 12, 2000.

NRC Request (Question 1)

"Please provide the following information:

a. When does the current 10-year inspection interval start and end?

b. When does the current inspection period start and end?

c. What cumulative percentage of inspections have been completed for the current interval?"

TVA Response

a. The current 10-year inservice inspection interval start and end dates are May 24, 1992, and May 24, 2001, respectively.

b. The current inspection period is the third of this interval and the start and end dates are May 24, 1998, and May 24, 2001, respectively.

c. The cumulative percentage of inspections that have been completed for the current interval for Examination Categories B-F, B-J, C-F-1, and C-F-2 are 62, 66, 61, and 67 percent, respectively.

NRC Request (Question 2)

"The implementation of a risk-informed inservice inspection (RI-ISI) program for piping should be initiated at the start of a plant's 10-year inservice inspection interval consistent with the requirements of the American Society of Mechanical Engineers (ASME) Code Section XI, Edition and Addenda committed to by the Owner in accordance with 10 CFR 50.55a. However, the implementation may begin at any point in an existing interval as long as the examinations are scheduled and distributed to be consistent with ASME XI requirements, e.g., the minimum examinations completed at the end of the three inspection intervals under Program B should be 16%, 50%, and 100%, respectively, and the maximum examinations credited at the end of the respective periods should be 34%, 67%, and 100%.

"It is our view that it is a virtual necessity that the programs for the risk-informed inspections and for the balance of the inspections be on the same interval start and end dates. This can be accomplished by either implementing the RI-ISIs at the beginning of the interval or merging RI-ISIs into the program for the balance of the inspections if the RI-ISIs are to begin during an existing ISI interval. One reason for this view is that it eliminates the problem of having different Codes of record for the RI-ISIs and for the balance of the inspections. A potential problem with using two different interval start dates and hence two different Codes of record would be having two sets of repair/replacement rules depending upon which program identified the need for repair (e.g., a weld inspection versus a pressure test).

"In addition, with the change to an RI-ISI program the Code minimum and maximum percentages of examination per period still apply to the RI-ISIs. For example, if a licensee is interested in starting the RI-ISIs during the second period, either the RI-ISIs or the Code required inspections should satisfy the second period minimum/maximum percentages. The code required percentages would have already been satisfied for the first period.

"Please describe your implementation plan with respect to the above discussion."

TVA Response

TVA agrees with the discussion presented by the staff in question 2 above. The BFN Unit 2 Risk-Informed Inservice Inspection (RI-ISI) program will run concurrently with the ASME Section XI program. Our plans are to implement the RI-ISI program, following NRC approval, during the third period of the second ten-year ISI interval. The third period examinations scheduled in the RI-ISI program would be merged into the ASME Section XI program time schedule. The ASME Section XI period percentage requirements have been met for the first two periods of the second inspection interval and the RI-ISI program percentages for the third period will be met for the subject examination categories.

When the BFN Unit 2 ASME Section XI program is updated in May 2001 for the third inspection interval, the RI-ISI program will begin at the first inspection period. This will ensure the required spacing between the RI-ISI components examined in the third period of the second interval and the components subsequently examined in the third period of the third inspection interval. As discussed by NRC in question 2 and TVA's response above, the methodology of merging the ASME Section XI program and the RI-ISI program will eliminate the need for different Codes of record and interval start dates between the programs.

NRC Request (Question 3)

"Will the RI-ISI program be updated every 10 years and submitted to the U.S. Nuclear Regulatory Commission (NRC) consistent with the current ASME XI requirements?"

TVA Response

Yes, the BFN Unit 2 RI-ISI program will be submitted with future ASME Section XI 10-year inservice inspection updates.

NRC Request (Question 4)

"Under what conditions will the RI-ISI program be resubmitted to the NRC before the end of any 10-year interval?"

TVA Response

The BFN Unit 2 RI-ISI program would be resubmitted to the NRC for approval, before the end of the 10-year inspection interval, if the RI-ISI methodology and/or inspection program is changed as a result of new information such as:

- industry initiatives to change augmented inspection programs (including IGSCC)
- significant changes to the PRA
- significant inspection results
- new failure modes experienced by the industry
- major replacement activities resulting from materials degradation or failure
- significant plant design or operational changes

The above is consistent with the requirements imposed by the NRC's SER for BFN Unit 3, dated February 11, 2000.

NRC Request (Question 5)

"The Westinghouse Commercial Atomic Power (WCAP) methodology requires that inspections for augmented programs should be credited in the "without ISI calculations" used to determine the risk significance of the segments. That is, the weld failure probability calculated for welds currently inspected in the Categories B through G under the current intergranular stress-corrosion cracking program should include the reduction in failure likelihood caused by these inspections. Did you include the inspections of the B through G welds while calculating the "without ISI calculations?" What was the frequency of the inspection used as input for each of the different Categories B through G?"

TVA Response

Scheduled BFN Unit 2 augmented inspections with a "good" probability of detection were included in the "without ISI" failure rate calculations for all welds inspected under the current IGSCC program. The frequencies used were as designated in the current augmented program.

NRC Request (Question 6)

"Our approval for the selection of only one "applicable" case ("with operator action" or "without operator action" for core damage frequency/large early release frequency (CDF/LERF)) for the Brown's Ferry 3 change in risk calculation was based on the simplicity of the actions that had to be performed and the time available for the operators to perform the action. Please describe the operator actions selected as the "applicable case" when the change in risk calculations were performed. In so far as these operator actions are covered in more detail in Question 7 below, they may be described in the answer to question 7."

TVA Response

See response to NRC question number seven below.

NRC Request (Question 7)

"On page 7 of your submittal you note that assigning segments with a risk reduction worth (RRW) >1.001 (instead of 1.005) as HSS was approved in lieu of doing a sensitivity study. We approved this in lieu of the sensitivity study and not as a extra defense in depth consideration as implied on page 17 of your submittal. Therefore, in your methodology, there is no difference between a segment with a RRW >1.005 and one with a RRW >1.001 although you seem to differentiate them in your submittal.

a. "In general, reduction of a high safety significance (HSS) to a low safety significance (LSS) by the expert panel requires careful consideration and justification. Page 18 of your submittal states that the expert panel placed six segments in LSS based on the ease of the operator action. Please describe each individual action, the detection mechanisms, and the time available for these actions.

b. "Review of your Attachment 1 indicates that there are seven segments that have RRW >1.001 without operator action that are not listed HSS, not six as page 18 of your submittal states. The seven are 2-067-003, 2-067-004, 2-067-005, 2-067-007, 2-071-011, 2-074-008, 2-074-009. Please explain this discrepancy."

TVA Response

The reference in the submittal to six segments was a typographical error. The seven listed segments each result in a flood of the Reactor Building without operator action. A revised page E1-18 of 64 of the BFN Unit 2 RI-ISI program, reflecting seven piping segments, is provided in Attachment A of this response.

For each of the segments where the RRW with operator action is 1.000, and the RRW with no operator action is greater than 1.001, the consequence without operator action could be an accumulation of water in the Reactor Building basement. The result of this water accumulation could result in the postulated loss of Residual Heat Removal (RHR) and Core Spray (CS) pumps due to submerging of the pumps or total loss of suction source. The postulated events would only occur following no operator action and would require an extended period of time to occur. The Expert Panel conducted a thorough review of the actions that would result from a leak in any of these segments. The following was considered.

Leak Observation

Operations personnel perform periodic observations in the Reactor Building a minimum of once each shift. These observations include looking for water leaks in all areas of the Reactor Building.

Personnel in other plant departments such as, RadChem, Security, Maintenance, Engineering, and Plant fire watch, frequently work in areas where any leaking water from these segments would accumulate. Plant personnel are expected to notify appropriate Operations personnel following the observation of any unusual conditions including fluid leaks. The areas that could exhibit leakage are where personnel routinely walk in the building, not in untraveled areas.

Leaks from segments would fall and accumulate to a normally dry concrete floor. The floor is open, for the most part, and not restricted by equipment to allow observation of water accumulation.

Leak Detection

Water accumulated on the Reactor Building floor would flow to the installed floor drains which are routed to the building sumps. The sumps are an integral part of the Reactor Building floor and equipment drain system and are equipped with sump pumps. The sumps have installed limit switches and alarms. The sump pumps are controlled by these limit switches.

Inleakage goals are established by plant management at a rate of less than eight gallons per minute for a 24 hour average for all inleakage from the three unit's floor drain systems. Inleakage status is reviewed by plant senior management in each plan of the day meeting.

The Reactor Building floor and equipment drains are monitored by Operations personnel each shift for changes that would indicate a new source of leakage. This would detect a small leak. The following alarms provide notification of increase sump levels.

- High level detected in the sump starts one sump pump. The Radwaste Operator monitors pump run times for excessive operation.

- High-High level detected in the sump starts the second sump pump and annunicates in the radwaste panel. The Radwaste Operator notifies the Main Control Room for the annunicated condition. This an Emergency Operating Instructions (EOI)-3 entry condition. EOI-3 requires actions to mitigate the leak. If these actions are not successful, the unit is shutdown.

- Torus level is monitored by Operations personnel in the Main Control Room. An abnormal Torus water level is an EOI-2 entry condition. EOI-2 requires actions to mitigate the leak. If these actions are not successful, the unit is shutdown.

- In addition to sump level monitors, each Reactor Building basement room has installed level switches. These switches independently and individually annuciate in the Main Control Room. Each room level annuciation requires EOI-3 entry. EOI-3 requires actions to mitigate the leak. If these actions are not successful, the unit is shutdown.

Leak Isolation

Operations training includes instruction in the EOIs, periodic refresher training, and simulation of all EOI-2 and EOI-3 entry conditions and response actions on a periodic basis. Simulator scenarios used for periodic training include both small leaks and catastrophic pipe failures.

The specific method of isolation for each postulated leak for which operator action is credited was reviewed by the Expert Panel. Methods of isolation include closing valves and/or securing pumps. In each specific case, location of the required valve(s) and or pump(s), accessibility, local and remote operational capability, procedural guidance and training was considered. In all cases reviewed, the Expert Panel confirmed the original determination that appropriate operator action will be taken to isolate postulated leaks.

NRC Request (Question 8)

"Does the High Energy Evaluation discussed in the Browns Ferry 2 submittal evaluate the spatial effects of the failure of high pressure piping that is normally on stand-by at low pressure? If not, how were the spatial effects of this piping evaluated?"

TVA Response

The "Indirect Consequences" discussion on page 13 of 64 of enclosure E1 indicates that cases where low pressure piping failure cause spray were evaluated with the results summarized in Table 3.3-3, Segments with Low Pressure Spray Potential. The potential for high energy pipe whip and jet impingement for piping normally on stand-by at low pressure was treated by the High Energy Pipe Rupture Evaluations.

NRC Request (Question 9)

"Page 22 states that all locations identified for examination are already identified under existing programs. On page 24 you state that in some instances locations may be found for which it is not possible to examine >90%. If you are already inspecting all the RI-ISI locations in your current programs, please explain how such a weld might be found."

TVA Response

Welds other than those listed in the current Unit 2 RI-ISI Program could be selected for examination due to additional examinations driven by indications revealed by scheduled examinations or program scope changes due to a periodic or event update. Additionally, with category percentage requirements, not all welds have necessarily been examined per current requirements given the age of the plant. Also, Note 1 in the Table of Code Case N-577 requires the examination volume to be increased to include 1/2-inch beyond each side of the base metal thickness transition or counterbore which would exceed current ASME volume coverage requirements.

NRC Request (Question 10)

"Please explain the LLO initiating event in Table 3.3-2 and the associated table entries. The values given seem inconsistent with the the other entries."

TVA Response

The data contained for initiating event LLO in the "Calculated CDF" column and the "IE Freq for Normalization" column for Table 3.3-2 should be interchanged. A revised page E1-12 of 64 of the BFN Unit 2 RI-ISI program, reflecting the corrected data, is provided in Attachment B of this response.

NRC Request (Question 11)

"You state that although all your RI-ISI locations are currently being inspected, the application is risk neutral when the change in CDF and LERF is evaluated. There are other risk criteria that must be met for a WCAP RI-ISI application contained in Section 4.4.2 of the WCAP. Please provide us with the results of your evaluation that allowed you to state that the risk/safety evaluation criteria in 4.4.2 of the WCAP are met."

TVA Response

Section 4.4.2 of the WCAP suggests four criteria for evaluation:

1. Total change in piping risk is risk neutral as discussed following Table 3.10-2 of the submittal.

2. The dominant system contributors were identified in Section 3.10. Each of these systems represents reduction in risk compared to current Section XI and risk neutrality compared to the combination of current Section XI and augmented programs. These systems received the most intense analysis during the program development and the proposed program represents the optimum inspection scheme.

3. HPCI and RCIC were identified as systems where there was a risk increase moving from the current Section XI program to the RI-ISI program; however, these increases were 2.04E-09 and 4.82E-11, respectively, compared to a total CDF of 1.32E-05 for the RI-ISI program. Additional examinations were identified in each of these systems.

4. The change in risk calculations credit all of the identified examinations.

NRC Request (Question 12)

"Risk informed regulation requires that all risk contributors are included in the decision making process, including shutdown and external event initiators. The WCAP methodology requires that when you are only using an internal events probability risk assessment, the expert panel should be provided with information on how the failures of the pipe segments could affect functions relied upon to mitigate external events. Please provide a sample of the information that the expert panel received to help them incorporate external events into their decision making process."

TVA Response

In accordance with section 3.6.2 of the WCAP, consideration was given to the function of each segment in mitigating external events, and to the likelihood of such events. All IPEEE external events were evaluated to be bound by the seismic evaluation, since the likelihood of piping failure would typically be much higher for seismic events compared to other IPEEE events i.e., transportation, external flooding, fire, or high wind loading. The function of piping segments in mitigating the effects of seismic events was considered as maintaining the design function of the segment during and following such an event. This was incorporated in the BFN Unit 2 analysis by including the applicable seismic stresses in the failure calculation for each segment. This was presented to and discussed by the Expert Panel on August 27,1998. The most limiting loads due to external events on the evaluated piping would be bounded by the above referenced seismic stresses, and during seismic events all evaluated piping would be affected, while other events would generally involve only localized piping effects. In addition, as mandated by the Expert Panel, piping segments were reviewed by a former Browns Ferry Senior Reactor Operator and system engineers to ensure adequate technical expertise was used in the evaluation of appropriate initiating events for each pipe segment. The results of these reviews were presented to the Expert Panel on several occasions and most notably during discussions of conditional core damage probabilities on August 27, 1998.

Attachment A

BFN Unit 2
Risk-Informed
Inservice Inspection Program

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Table 3.7-2 Defense in Depth Segments					
Segment	Description	Segment CDF	%Applicable CDF	Cum % CDF	RRW
2-001-036	26" discharge line from Reactor to penetration X-7A including valves PCV-1-4, 179, 5 and penetrations X-34A and X-30A	3.84E-08	0.18%	97.03%	1.002
2-001-037	26" discharge line from Reactor to penetration X-7B including valves PCV-1-18, 19, 22, 23 and penetrations X-34B and X-30B	3.84E-08	0.18%	97.21%	1.002
2-001-038	26" discharge line from Reactor to penetration X-7C including valves PCV-1-30, 31, 34, and penetrations X-34C and X-30C	3.84E-08	0.18%	97.39%	1.002
2-001-039	26" discharge line from Reactor to penetration X-7D including valves PCV-1-41, 180, 42 and penetrations X-34D and X-30D	3.84E-08	0.18%	97.57%	1.002
2-003-006	24" supply line from penetration X-9A to HCV-3-67	3.84E-08	0.18%	97.75%	1.002
2-003-007	24" supply line from penetration X-9B to HCV-3-66	3.84E-08	0.18%	97.93%	1.002
2-003-036	20" supply line from HCV-3-67 to 12" inlet piping - ring header	3.84E-08	0.18%	98.11%	1.002
2-003-037	12" supply line from 20" ring header to Reactor (N4A)	3.84E-08	0.18%	98.29%	1.002
2-003-038	12" supply line from 20" ring header to Reactor (N4B)	3.84E-08	0.18%	98.47%	1.002
2-003-039	12" supply line from 20" ring header to Reactor (N4C)	3.84E-08	0.18%	98.65%	1.002
2-003-040	20" supply line from HCV-3-66 to 12" inlet piping - ring header	3.84E-08	0.18%	98.83%	1.002
2-003-041	12" supply line from 20" ring header to Reactor (N4F)	3.84E-08	0.18%	99.01%	1.002
2-003-042	12" supply line from 20" ring header to Reactor (N4E)	3.84E-08	0.18%	99.19%	1.002
2-003-043	12" supply line from 20" ring header to Reactor (N4D)	3.84E-08	0.18%	99.37%	1.002
2-069-003	4"-8" line from regenerative heat exchanger "2B" to feedwater tie in at penetration X-9B and RCIC tie in	3.36E-08	0.16%	99.53%	1.002
2-068-010	12" discharge line from Recirc ring header "B" to Reactor (N2D)	2.14E-08	0.10%	99.63%	1.000
2-068-009	12" discharge line from Recirc ring header "B" to Reactor (N2E)	1.98E-08	0.09%	99.72%	1.000
2-074-013	24" discharge line from penetration X-13B to Recirculation line "A"	6.25E-09	0.03%	99.75%	1.000
2-073-001	10" supply line from 26" MS line "B" to penetration X-11	2.10E-09	0.01%	99.76%	1.000
2-068-002	28" discharge line from Recirculation pump "A" to Recirc ring header	1.12E-09	0.01%	99.77%	1.000
2-068-012	12" discharge line from Recirc ring header "B" to Reactor (N2B)	8.63E-18	0.00%	99.77%	1.000
2-068-006	12" discharge line from Recirc ring header "A" to Reactor (N2H)	6.75E-19	0.00%	99.77%	1.000
2-068-016	28" suction line from Reactor (N1B) to Recirculation pump "B"	1.58E-22	0.00%	99.77%	1.000
2-068-014	28" discharge line from Recirculation pump "B" to Recirc ring header	0.00E+00	0.00%	99.77%	1.000
2-075-001	12" discharge line from MPEN-100-16B to reactor (N5B)	4.67E-19	0.00%	99.77%	1.000
2-075-002	12" discharge line from MPEN-100-16A to reactor (N5A)	3.49E-18	0.00%	99.77%	1.000

Large Early Release Frequency (LERF) was also considered in determining segment significance. All segments with a LERF RRW >1.001 were already selected for examination as high safety significant segments based on CDF RRW.

The applicable CDF and LERF together with the CDF and LERF both with and without operator action for each segment and the corresponding RRW values are provided in Attachment 1.

There were seven segments with RRW >1.001 <1.005 if no operator action was credited. None of these segments had RRW >1.001 with operator action. These segments received special consideration by the Expert Panel. The increased RRW with no operator action in each case was due to isolable flooding as a result of the pipe failure. The Expert Panel determined that this flooding was not a credible consequence of failure due to the training and work practices in effect specifically to deal with such an occurrence. The Expert Panel determined that the segments

Attachment B

BFN Unit 2
Risk-Informed
Inservice Inspection Program

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Table 3.3-1 Summary of Quantification Runs Where Segment Failure does not result in Plant Trip				
Initiating Event	Mitigating System impact	Calculated CDF	CDF Increase (Annual)	Surv Interval
All	Core Spray loop I	9.01E-06	3.62E-06	qtrly
All	HPCI	1.12E-05	5.81E-06	qtrly
All	RHR Pump A	2.59E-05	2.05E-05	mthly
All	RPASUP, RPCSUP	7.15E-05	6.61E-05	mthly
All	Diesel Generator	1.18E-05	6.41E-06	mthly
All	RHR Heat Exchanger A	7.34E-06	1.95E-06	qtrly
All	RCIC	1.465E-05	9.26E-06	qtrly
All	Suppression Pool Cooling	6.68E-06	1.29E-06	qtrly

The surveillance interval referenced in the table represents the period between surveillance tests or physical observation of the affected system or component. This is used to determine the appropriate Surveillance Interval Adjustment factor.

Table 3.3-2 summarizes the results of the individual cases evaluated where failure of a pipe segment could result in an initiating event and also impact operability of a mitigating system or systems. RISKMAN calculations were made for the listed combinations of circumstances, and the resultant Core Damage Frequency was normalized to an annual CCDP by dividing by the initiating event frequency.

Table 3.3-2 Summary of Quantification Runs Where Segment Failure Results in Plant Trip with Mitigating System Impact				
Initiating Event	Mitigating System impact	Calculated CDF	IE Freq for Normalization	CCDP (normalized)
CIV	HPI	1.386E-06	4.34E-01	3.19E-06
CIV	RCI, CRD	2.895E-05	4.34E-01	6.67E-05
LLO	subsumes HPI, RCI, CRD	3.16E-08	1.07E-04	2.95E-04
LRCW	250V RMOV 2C	2.8E-06	3.22E-02	8.70E-05
PLFW	RCI, CRD	2.906E-06	3.31E-01	8.78E-06
RXINST (calc as UI)	incl LM, LV, LVP	4.187E-09	6.58E-04	6.36E-06
SCRAMR	CRD	5.02E-07	2.74E-01	1.83E-06
SCRAMR	RPB, RPD, HPI, 6.9E-3exp	1.11E-06	2.74E-01	4.05E-06
SCRAMR	SL	5.698E-06	7.74E-01	2.08E-06
SLOCA	RCI	7.363E-08	4.01E-04	1.84E-05

The loss of shutdown cooling is represented by Top Event SDC which has an Achievement Worth of 1.316, which results in a calculated CDF of 7.093E-06 per year. Since SDC is based on the plant shut down, no Initiating Events are considered and the base CDF for all Initiating Events is not adjusted out of the CDF for SDC.