Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402-2801

September 30, 2004

10 CFR 54
10 CFR 51

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop: OWFN P1-35
Washington, D.C. 20555-0001

Gentlemen:

In the Matter of	)	Docket Nos. 50-259
Tennessee Valley Authority	)	50-260
		50-296

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI) REGARDING SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR BROWNS FERRY NUCLEAR PLANT (BFN), UNITS 1, 2, AND 3 (TAC NOS. MC1768, MC1769, AND MC1770)

By letter dated August 20, 2004, the Nuclear Regulatory Commission (NRC) requested additional information to complete its review of the Tennessee Valley Authority's (TVA) analysis of severe accident mitigation alternatives submitted in support of TVA's application to renew the operating licenses for BFN, Units 1, 2, and 3. Enclosed is TVA's response to the NRC staff's RAI.

This letter contains no new commitments.

If you have any questions, please contact Chuck Wilson, Project Manager for BFN License Renewal Environmental Review, at (423) 751-6153 or clwilson@tva.gov.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 30th day of September 2004.

Sincerely,

Fredrick C. Mashburn
Senior Program Manager
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A001
A105

Enclosure
cc: See page 2

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TVA RESPONSES TO NRC REQUESTS FOR ADDITIONAL INFORMATION (RAIs) REGARDING ANALYSIS OF SEVERE ACCIDENT MITIGATION ALTERNATIVES (SAMAs) FOR BROWNS FERRY NUCLEAR PLANT (BFN) UNITS 1, 2, AND 3

Part I. Questions Pertaining to the July 7, 2004, TVA Submittal

1c. The CDF for each unit decreased significantly from the IPE, Rev 0 to the PSA Rev. 0 update and then increased in the EPU PSA revision. The response to RAI 1c summarized the changes made to each of these models. Identify which of these changes had the most significant impact on CDF.

RESPONSE:

IPE Rev 1A Versus IPE Rev 0.

The change made in IPE Rev 1A that had the most significant impact on (lowering of) the CDF compared with the IPE Rev 0 was the Loss of Offsite Power contribution.

The following changes were made that reduce the LOSP contribution to the total core damage frequency:

- Use of plant specific diesel generator failure rates. These were lower than the generic values used in Rev 0
- Rev 1A credited powering the Unit 2 4kV shutdown boards through the emergency feeder breakers to the associated Unit 3 4kV shutdown boards.
- Rev 1A used the electric power recovery curves (NUREG/CR-5032) that more closely model the switchyard configuration at BFN; this resulted in a higher likelihood of recovering AC power.

Multi-Unit PRA Versus IPE Rev 1A.

The most significant factor for the increase in Unit 2 CDF in the Multi-Unit PRA from the IPE Rev 1A was exactly that; all three units are in operation. This is the most limiting plant configuration. The two significant features were:

1. Modeling of the "Multiple Unit" initiators – that is, initiating events that have the potential to impact more than one operating unit. For example, turbine building flooding events, LOSP and loss of the Raw Cooling Water (RCW) system.

2. Changes in the success criteria for shared systems such as diesel generators and the residual heat removal service water (RHRSW) system for initiating events that could impact two or three units concurrently. In such events, no credit is taken for using equipment from other units.

Unit 2/3 PRA Versus Multi-Unit PRA.

The most significant factor that impacted (decreased) the Unit 2 CDF in the Unit 2/3 PRA (Unit 2 PRA with Unit 3 operating) versus the Multi-Unit PRA was the refinement of the model for floods in the turbine building. Two turbine building flooding initiating events (very large flood and less severe flood) were defined for the Unit 2/3 PRA instead of a single turbine building flooding event in the Multi-Unit PRA. The different sizes of the floods have different impact on the plant.

Unit 2 PSA Rev 0 Versus Unit 2/3 PRA.

Several factors contributed to a decrease in the Unit 2 CDF in going from the Unit 2/3 PRA to the Unit 2 PSA Rev 0. There were no changes to the models that individually had a significant impact on the CDF.

1. Use of revised transient initiating event frequencies from NUREG/CR-5750.
2. Use of updated plant specific component failure rates and the use of revised cause failure parameters.

EPU PSA Versus Unit 2 PSA Rev 0.

The increase in the CDF in going from the Unit 2 PSA Rev 0 to the EPU PSA was almost entirely due to the elimination of use of the CRD System as an effective source of high pressure injection. The results of the MAAP model at EPU conditions showed that the CRD system flow rate is not sufficient to maintain adequate core cooling.

1d. The response to RAI 1d indicates that Table III-5 in Attachment E-4 refers to the definition of the KPDSs in the IPE and the corresponding definition of cases for which MAAP runs were made at that time. It also states that the plant damage state assignment rules used to identify the PDS for each Level 1 accident sequence remain the same as the IPE. It is also stated in the original submittal (Attachment E-4, Section III.B, p.E-416) that the KPDSs are the same as in the 1992 IPE submittal.

A comparison of the KPDSs identified for the SAMA analysis with those listed in the IPE indicates that there are some differences including: 8 KPDSs in the SAMA analysis and either 9 or 10, depending on table of the IPE; 3 KPDSs in the IPE that are not included in the SAMA list and 2 KPDSs in the SAMA list that are not in the IPE. KPDS PIH is described in the response to RAI 1d and has a frequency of 1E-12 versus 3E-05 in the IPE. It is stated that station blackouts sequences are mapped to KPDS MIB since drywell sprays (DWS) can operate due to the crosstie with Unit 3's electric power.

1d(a) Provide a version of Table III-5 which includes the Level I sequences that are the major contributors to the KPDSs.

RESPONSE:

The following two tables list the key plant damage states used in the Unit 2 IPE and in the Unit 2 and Unit 3 SAMA analyses respectively.

Single Largest Sequence or Sequence Class per Key Plant Damage State – Unit 2		
Key Plant Damage State		Sequence Description
Name	Description	
MIA	Containment isolated, water available to core debris, drywell spray available, suppression pool cooling available, vessel at high pressure at time of melt with water on drywell floor	Loss of condenser heat sink (initiator) RCIC and HPCI hardware failures Operator failure to initiate depressurization
MKC	Containment not isolated or failed early, water available to core debris, drywell spray available.	General Transient (initiator) Reactor scram failure Operator failure to start standby liquid control system
NIH	Containment isolated, water not available to core debris, vessel at high pressure at time of melt with no water on drywell floor	Loss of Offsite Power (initiator) Diesel A failure Diesel B failure Diesel D failure Failure to recover electric power
OIA	Containment isolated, water available to core debris, drywell spray available, suppression pool cooling available, vessel at low pressure at time of melt with water on drywell floor	Excessive LOCA (initiator)
PID	Containment isolated, water available to core debris, drywell spray not available, suppression pool cooling available, vessel at low pressure at time of melt with no water on drywell floor	No significant frequency*
PIH	Containment isolated, no water available to core debris, drywell spray not available, suppression pool cooling not available, vessel at low pressure at time of melt with no water on drywell floor	No significant frequency*

Single Largest Sequence or Sequence Class per Key Plant Damage State – Unit 2		
Key Plant Damage State		Sequence Description
Name	Description	
PJH	Containment bypassed, water available to core debris, vessel at low pressure at time of melt with no water on drywell floor	Interfacing System LOCA (initiator)
PLF	Containment failed late, water available to core debris, drywell spray not available, suppression pool cooling not available, vessel at low pressure at time of melt with no water on drywell floor	General Transient (initiator) Loss of main condenser Failure of RHR heat Exchangers A, B, C and D Failure to cross tie to Unit 1 RHR Failure to cross tie to Unit 3 RHR Operator failure to open wet well vent
* No sequences above 1.0E-10		

Single Largest Sequence or Sequence Class per Key Plant Damage State – Unit 3		
Key Plant Damage State		**Sequence Description**
Name	**Description**	
MIA	Containment isolated, water available to core debris, drywell spray available, suppression pool cooling available, vessel at high pressure at time of melt with water on drywell floor	Loss of condenser heat sink (initiator) RCIC and HPCI hardware failures Operator failure to initiate depressurization
MKC	Containment not isolated or failed early, water available to core debris, drywell spray available.	General Transient (initiator) Reactor scram failure Operator failure to start standby liquid control system
NIH	Containment isolated, water not available to core debris, vessel at high pressure at time of melt with no water on drywell floor	Loss of Offsite Power (initiator) Diesel 3A failure Diesel 3C failure Diesel 3B failure Diesel B failure Failure to recover electric power
OIA	Containment isolated, water available to core debris, drywell spray available, suppression pool cooling available, vessel at low pressure at time of melt with water on drywell floor	Excessive LOCA (initiator)
PID	Containment isolated, water available to core debris, drywell spray not available, suppression pool cooling available, vessel at low pressure at time of melt with no water on drywell floor	No significant frequency*
PIH	Containment isolated, no water available to core debris, drywell spray not available, suppression pool cooling not available, vessel	No significant frequency*

Single Largest Sequence or Sequence Class per Key Plant Damage State – Unit 3		
Key Plant Damage State		Sequence Description
Name	Description	
	at low pressure at time of melt with no water on drywell floor	
PJH	Containment bypassed, water available to core debris, vessel at low pressure at time of melt with no water on drywell floor	Interfacing System LOCA (initiator)
PLF	Containment failed late, water available to core debris, drywell spray not available, suppression pool cooling not available, vessel at low pressure at time of melt with no water on drywell floor	General Transient (initiator) Loss of main condenser Failure of RHR heat Exchangers A, B, C and D Failure to cross tie to Unit 2 RHR Operator failure to open wet well vent
* No sequences above 1.0E-10		

1d(b) Discuss the discrepancies between the KPDSs used for the SAMA analysis versus those identified for the IPE.

RESPONSE:

Key Plant Damage State	**Included in IPE**	**Included in SAMA Analysis**
PIH	Yes	Yes
OIA	Yes	Yes
MIA	Yes	Yes
PID	Yes	Yes
NIH	Yes	Yes
NLF	Yes	No. Plant damage state NLF binned into key damage state PLF.
MKC	Yes	Yes
OJA	Yes	Yes
NJA	Yes	Yes
PJH	No. Frequency of plant damage state <<1% of core damage.	Yes
PLF	No. Plant damage state binned into key plant damage state NLF.	Yes

1d(c) Discuss why the frequency of KPDS PIH has been reduced by six orders of magnitude with the PDS assignment rules being the same as for the IPE.

1d(d) Discuss the modeling of use of the electric cross tie to Unit 3 for Unit 2 SBOs. Wouldn't DWS fail for some of the SBO sequences? To what KPDSs are these sequences assigned?

RESPONSE:

The top 80 sequences of the IPE PRA (constituting 50% of the CDF) were examined for the characteristics of the PIH sequences. LOSP initiator was the most significant contributor with about 73% of sequences going to plant damage state PIH. Although these sequences were defined as SBO sequences, only 44% were scenarios with all diesels failed. Scenarios with 3 or 2 diesels failed accounted for 28% or the PIH scenarios.

The SBO sequences contributing significantly to the plant damage state PIH in the IPE have the following characteristics:

- Complete loss of offsite power
- Diesel generators 3A, 3B, 3C and 3D fail
- Failure to recover offsite power in 30 minutes
- Successful battery load shedding allows battery life of 4 hours
- At four hours, HPCI and RCIC fail
- Failure to recover power after 6 hours. If level control can be established within 6 hours, successful termination of these scenarios is possible.

Changes have been made to the model successively since the IPE to reduce the frequency of such scenarios.

1. Loss of offsite power frequency is now a plant-specific value as opposed to generic value for the IPE. It is now almost an order of magnitude lower.
2. The failure rates and maintenance unavailabilities of the diesel generators were updated using plant specific data and this resulted in a reduction for the total unavailability of the diesel generators. This reduces the frequency of station blackout scenarios.
3. The IPE model assumed Unit 3 diesel generators would fail given the failure of all Unit 1/2 diesel generators. A maximum of four diesel generators were modeled explicitly. For the later PRAs, the common cause model for the diesel generator was enhanced using an expansion of the Multiple Greek Letter (MGL) factors to allow for success of the fifth, sixth, seventh and eighth diesel generators. This reduces the frequency of station blackout scenarios.

4. Electric power recovery curves (NUREG/CR-5032) that more closely model the switchyard configuration at BFN were used after the IPE and this resulted in a higher likelihood of recovering AC power.

For the scenarios with 2 or 3 diesel/generators failed after loss of offsite power, if power can be restored by the actions described below, the character of the scenario is changed so that it no longer fits into PIH:

5. Unit 2 4kV shutdown boards were provided power through the emergency feeder breakers to the appropriate Unit 3 4kV board.
6. Operator action to recover one of the failed Battery Boards 2 or 3 by aligning a charger (2B) to the board was added.

1d. The response to RAI 1d indicates that the release categories (RC) used in the MACCS2 analysis have a one-to-one relationship with the KPDSs. In the IPE, the KPDSs are mapped to key release categories utilizing a containment event tree. The discussion in Section 4 of the IPE appears to indicate that KPDSs may be assigned to more than one release category.

a. Discuss the basis for assigning a one-to-one relationship between KPDSs and release categories.

b. Describe the source of the release fractions for the release categories as given in Table II-4. If these are based on MAAP analysis, please provide a comparison of the accident sequence analyzed with the major contributors to the PDS/RC and discuss the relevance, conservatism and nonconservatism of the sequence analyzed and chosen to be representative of the PDS/RC.

RESPONSE:

The release fractions were determined from runs of the MAAP-BWR Severe Accident Analysis Code, Version 3.0b Revision 7.03. The raw results were transferred to a Microsoft® Excel 2000 Spreadsheet, where the masses of elements and compounds were converted into release fractions as a function of time. The results were examined, and divided into release phases (MACCS2 plumes) by an analyst with expertise in consequence analysis.

The complete set of plant damage states includes many plant damage states. Some of these are impossible because of physical or logical impossibilities. Many others have relatively small probabilities of occurrence. The consequences for these plant damage states are each represented by another plant damage state (the Key Plant Damage State or KPDS). The name of the KPDS is used as the name of the release category to prevent confusion in assembling the data. In some cases, the name of the representative MAAP run is not the same as the KPDS, so the MAAP run names are also listed in the Table 1d-1.

Table 1d-1									
Key Plant Damage State	MAAP Run	Vessel Pressure	Drywell Floor	Torus Cooling	Torus Vent	Water to Core Debris	Drywell Sprays	RPV Failure Time (hours)	Containment Failure Time (hours)
MKC	ENMKCTT	High	Wet	N/A	N/A	Yes	Yes	2.3	0.36
MIA	MIALF	High	Wet	Yes	N/A	Yes	Yes	3	3
NIH	NIH	High	Dry	N/A	No	No	No	10	10
OIA	OIA	Low	Wet	Yes	N/A	Yes	Yes	5	5
PID	PID	Low	Dry	Yes	N/A	Yes	No	22	22
PIH	PIHDEP	Low	Dry	N/A	No	No	No	10	10
PJH	PJH	Low	Dry	N/A	N/A	No	N/A	1.4	0
PLF	PLF	Low	Dry	N/A	N/A	Yes	No	>100	39

Table 1d-2 shows the differences between each Plant Damage State (PDS) and the Key Plant Damage State (KPDS) modeled in the MAAP run used to represent that PDS, and gives the rationale why the KPDS can be used to represent that PDS.

Table 1d-2		
PDS	**KPDS**	**Rationale For This Representation**
MIB	MIA	Both sequences result in a coolable debris bed, but MIB has suppression pool venting, while MIA has an early drywell failure due to corium impingement, making this mapping conservative.
MIC	MIA	Both sequences result in a coolable debris bed, but MIC results in a late drywell failure due to overpressure, while MIA represents an early failure due to corium impingment, making this mapping conservative.
NID	MIA	Both sequences result in a coolable debris bed with drywell failed early due to corium impingment, making this mapping conservative.
NIE	NIH	NIE results in a coolable debris bed, while NIH results in a non-coolable debris bed, making this mapping conservative.

Table 1d-2		
PDS	**KPDS**	**Rationale For This Representation**
NIF	NIH	NIF results in a coolable debris bed, while NIH results in a non-coolable debris bed, making this mapping conservative.
NIG	NIH	Both sequences result in a non-coolable debris bed with drywell failed early due to corium impingment, making this mapping conservative.
OIF	NIH	OIF results in a coolable debris bed with late drywell failure due to overpressure, while NIH results in a non-coolable debris bed with drywell failed early due to corium impingment, making this mapping conservative.
OIB	OIA	Both sequences result in coolable debris beds. OIB has suppression pool venting, while OIA results in early drywell failure due to corium impingment, making this mapping conservative.
OIC	OIA	Both sequences result in coolable debris beds. OIC has late drywell failure due to overpressure, while OIA results in early drywell failure due to corium impingment, making this mapping conservative.
OID	OIA	Both sequences result in coolable debris beds. OID has no containment failure, while OIA results in early drywell failure due to corium impingment, making this mapping conservative.
PIE	PIH	Both sequences represent early drywell failure due to corium impingment, but PIE has a coolable debris bed, while PIH has a non-coolable debris bed, making this mapping conservative.
PJA	PJH	Both sequences represent early containment bypass, but PJA has a coolable debris bed, while PJH has a non-coolable debris bed, making this mapping conservative.
OKC	MKC	Both sequences represent a coolable debris bed with the drywell not isolated or failed early. OKC is a low-pressure sequence, while MKC is a high-pressure sequence, making this mapping conservative.
OKF	MKC	Both sequences represent a coolable debris bed with the drywell not isolated or failed early. OKF is a low-pressure sequence, while MKC is a high-pressure sequence, making this mapping conservative.
OKH	MKC	Both sequences have the drywell not isolated or failed early. OKH is a low-pressure sequence with a non-coolable debris bed. MKC sequences are represented with ATWS sequences and has the most severe source term of the available analyses. Vessel failure occurs after drywell failure.
NKF	MKC	Both sequences represent a coolable debris bed with the drywell not isolated or failed early. NKF has a dry drywell floor without drywell sprays, while MKC has a wet drywell floor with drywell sprays. MKC sequences are represented with ATWS sequences and has the most severe source term of the available analyses. Vessel failure occurs after drywell failure.

Table 1d-2		
PDS	**KPDS**	**Rationale For This Representation**
NKH	MKC	Both sequences have the drywell not isolated or failed early. NKH has a non-coolable debris bed. MKC sequences are represented with ATWS sequences and has the most severe source term of the available analyses. Vessel failure occurs after drywell failure.
OLC	PLF	Both sequences have a coolable debris bed with the drywell failed late, but OLC has a wet drywell floor and drywell sprays that are not present in PLF, making this mapping conservative.
OLF	PLF	Both sequences have a coolable debris bed with the drywell failed late, but OLF has a wet drywell floor that is not present in PLF, making this mapping conservative.
NLF	PLF	Both sequences have a coolable debris bed with the drywell failing prior to core melt, making this mapping conservative.
NLH	PLF	Both sequences have a late drywell failure, but NLH has a non-coolable debris bed, and PLF has a coolable debris bed. The NLH frequency represents about 0.4% of the total CDF and about 3.5% of the total PLF frequency. The mapping is non-conservative but with minor impact to the overall results.
MLC	PLF	Both sequences result in a coolable debris bed with late drywell failure. MLC is a high-pressure sequence with a wet drywell floor, while PLF is a low-pressure sequence with a dry drywell floor. This mapping is conservative.

1f. The response to RAI 1f states that neither KPDSs MIA nor OIA are expected to lead to containment failure, but that these KPDSs are nevertheless assumed to lead to early and late containment failure, respectively. Discuss the rationale for assuming these KPDSs lead to containment failure, particularly given the relaxations on the use of drywell sprays in Revision 2 of the Emergency Procedure and Severe Accident Guidelines, and given that this assumption results in the intact containment release mode contributing over 50% of the total person-rem dose.

RESPONSE:

The SAMA analysis did not include a reassessment of the Level 2 portion of the IPE. Instead, the Level 2 analyses that were performed as part of the IPE and later updates were used to support a conservative screening process appropriate for the evaluation of SAMAs.

KPDSs MIA and OIA are not expected to result in a failed containment. Nevertheless, conservative MAAP evaluations that assumed containment failure were used for such cases in the SAMA screening process. This assumption clearly overestimates the release and subsequent offsite impact. The expected releases and impacts would be less than those used in this screening analysis. This approach allowed the maximum use of existing information, provided a sound basis for screening, and eliminated any need to perform additional Level 2 analyses.

2d/3. The contribution to CDF from loss of raw cooling water (RCW) initiators has increased by a factor of 76 and accounts for 20% of CDF in the multi-unit PRA (see RAI 3 response). Although this contribution could be reduced by taking credit for the RHR cross-tie, this would not solve all problems on loss of RCW. Provide the importance of the RCW system. Address whether a low cost SAMA involving use of fire water would be effective for this risk contributor.

RESPONSE:

Based on the RCW top event importance (hardware failure in response to an initiating event) and also the loss of RCW initiating event contribution to CDF, the contribution of RCW failures to core damage is approximately 2.6% for Unit 2 and 2.5% for Unit 3.

The RCW flow for 3 units in operation at extended power uprate is about 43,850 gpm. The rated flow for the high pressure fire water pumps that might be considered as an alternative to the RCW system are as follow:

- 3 emergency fire pumps, each with 2500 gpm @ 300 feet head
- 1 vertical fire pump 2500 gpm @ 340 feet head

Based on the above flow rates, the Fire Protection System cannot meet the RCW System flow demand.

3. **The response to RAI 3 states that higher CDF values for three unit operation would be anticipated due to shared systems including: diesel generators, emergency equipment cooling water system (EECW), residual heat removal service water system (RHRSW) and raw cooling water. It addresses the variation in the "all unit operating adjustment factor" from sequence to sequence by considering the conservatism in the multi-unit PRA analysis for those initiating events with factors greater than 4. While the diesel generators are demanded by the LOSP initiator and the raw cooling water system is a support system initiator, the impact of three unit operation on sequences that involve the EECW and RHRSW are not specifically addressed. If the importance of these systems are sufficiently high and the impact of 3 unit operation on their availability is sufficiently high, SAMAs that affect these systems could have an impact greater than the factors based on the total CDF. What is the ratio of the importance of the Unit 2 EECW and RHRSW systems (that is, the CDF involving failures of these systems) in the MUPRA to that in the 1995 PRA? Should SAMAs for these systems be considered?**

   In the response to RAI 3, the impact of 3 unit operation on the CDF due to the small turbine building flood is discussed. The meaning of the last sentence is not clear. To what is the factor of 5.5 applied?

RESPONSE:

Table 3-2 of the first SAMA RAI response (July 7, 2004) presents the CDF results for those Multi-Unit PRA initiating events that have a significant increase over a single unit model (more than $1x10^{-8}$ per reactor year). Failure of EECW or RHRSW do not result in a plant trip and are not evaluated initiators in the PRA models. Those initiating events that impact multiple units and could place increased demands on the EECW and RHRSW systems (as compared to initiators in which only one unit must respond) are included in Table 3-2.

The four EECW pump trains are modeled in Top Events EA, EB, EC and ED of the Mechanical Support Systems Event Tree. The dominant contributors to failure of each pump train (given required supports are available) and the dominant contributors to failure of all four pump trains are provided in Table 3-3. Pump Trains A and B are assumed to be operating at the time of the initiating event, while Pump Trains C and D are in standby and are required to start.

Table 3-3 EECW System Cutsets		
EECW Train A (running) Unavailability [4.1E-04]		
Dominant Contributors		% Contribution
1	Train A Pump fails to run	57
2	Plugging of Strainer A3	36
	(no other cutsets greater than 2%)	
EECW Train B (running) Unavailability [4.1E-04]		
Dominant Contributors		% Contribution
1	Train B Pump fails to run	57
2	Plugging of Strainer B3	36
	(no other cutsets greater than 2%)	
EECW Train C (standby) Unavailability [2.6E-03]		
Dominant Contributors		% Contribution
1	Train C Pump fails to start	48
2	Check Valve 0-67-671 fails to open	11
3	Check Valve 0-23-594 fails to open	11
4	Train C Pump fails to run	9
5	Plugging of Strainer C3	6
6	Unavailablity due to errors during test	5
	(no other cutsets greater than 2%)	
EECW Train D (standby) Unavailability [2.6E-03]		
Dominant Contributors		% Contribution
1	Train D Pump fails to start	48
2	Check Valve 0-67-619 fails to open	11
3	Check Valve 0-23-597 fails to open	11
4	Train D Pump fails to run	9
5	Plugging of Strainer D3	6
6	Unavailablity due to errors during test	5
	(no other cutsets greater than 2%)	
Unavailability of EECW Trains A, B, C and D [4.9E-06]		
Dominant Contributors		% Contribution
1	Pumps A, B, C and D - Common cause failure to run	99
	(no other cutsets greater than 0.1%)	

The eight RHRSW pump trains are modeled in Top Events SW1A, SW1B, SW1C, SW1D, SW2A, SW2B, SW2C and SW2D of the Mechanical Support Systems Event Tree. Common cause failure of the eight RHRSW pumps to start and run is modeled in Top Event SWC. The dominant contributors to failure of each pump train, given required supports are available, and the dominant contributors to failure of all eight pump trains are provided in Table 3-4.

***Table 3-4* RHRSW System Cutsets**		
RHRSW Train A2 Unavailability [6.5E-03]		
Dominant Contributors		% Contribution
1	Train A2 Pump maintenance unavailability	70
2	Train A2 pump fails to start	12
3	Train A2 pump fails to run	9
4	Discharge check valve fails to open	4
	(no other cutsets greater than 1%)	
RHRSW Train A1 Unavailability [2.2E-02]		
Dominant Contributors		% Contribution
1	Train A1 Pump maintenance unavailability	91
2	Train A1 pump fails to start	4
3	Train A1 pump fails to run	3
4	Discharge check valve fails to open	1
	(no other cutsets greater than 1%)	
RHRSW Train B2 Unavailability [6.5E-03]		
Dominant Contributors		% Contribution
1	Train B2 Pump maintenance unavailability	70
2	Train B2 pump fails to start	12
3	Train B2 pump fails to run	9
4	Discharge check valve fails to open	4
	(no other cutsets greater than 1%)	
RHRSW Train B1 Unavailability [2.2E-02]		
Dominant Contributors		% Contribution
1	Train B1 Pump maintenance unavailability	91
2	Train B1 pump fails to start	3
3	Train B1 pump fails to run	3
4	Discharge check valve fails to open	1
	(no other cutsets greater than 1%)	

RHRSW Train C2 Unavailability [6.5E-03]		
Dominant Contributors		% Contribution
1	Train C2 Pump maintenance unavailability	70
2	Train C2 pump fails to start	12
3	Train C2 pump fails to run	9
4	Discharge check valve fails to open	4
	(no other cutsets greater than 1%)	
RHRSW Train C1 Unavailability [2.2E-02]		
Dominant Contributors		% Contribution
1	Train C1 Pump maintenance unavailability	91
2	Train C1 pump fails to start	4
3	Train C1 pump fails to run	3
4	Discharge check valve fails to open	1
	(no other cutsets greater than 1%)	
RHRSW Train D2 Unavailability [6.5E-03]		
Dominant Contributors		% Contribution
1	Train D2 Pump maintenance unavailability	70
2	Train D2 pump fails to start	12
3	Train D2 pump fails to run	9
4	Discharge check valve fails to open	4
	(no other cutsets greater than 1%)	
RHRSW Train D1 Unavailability [2.2E-02]		
Dominant Contributors		% Contribution
1	Train D1 Pump maintenance unavailability	91
2	Train D1 pump fails to start	3
3	Train D1 pump fails to run	3
4	Discharge check valve fails to open	1
	(no other cutsets greater than 1%)	

Unavailability of All RHRSW Trains[7.1E-07]		
Dominant Contributors		% Contribution
1	Common cause failure to start of all RHRSW pumps	59
2	Common cause failure to run of all RHRSW pumps	41
	(no other cutsets greater than 1%)	

Failure of EECW or RHRSW does not result in a plant trip. Both systems support standby systems. Of the 12 EECW/RHRSW pumps, four are dedicated to EECW, four to RHRSW and four can be aligned to either EECW or RHRSW. EECW flow is delivered to all three units via two headers, with one pump normally running to provide flow to its respective header. RHRSW pumps are normally in standby.

The addition of a redundant system for EECW and RHRSW or the addition of redundant pumps are not cost effective. The rationale for this conclusion is outlined below.

First, the cost associated with either a redundant system or redundant pumps would be large.

Second, the decrease in risk would be small or modest.

The importance of EECW (as measured by ratio of the sum of the frequency of the core damage sequences with one or more EECW pump failed to the total core damage frequency) is small (less than 1%) if electrical support is available for the EECW pumps. Likewise the importance of RHRSW is small (on the order of 1%) if electrical support is available. The large number of pumps and the flexibility to align swing pumps to either EECW or RHRSW is an important feature contributing to this result.

Functional failure of EECW occurs in sequences totaling approximately 10% of the core damage frequency. Most of these scenarios involve degraded or failed electrical states. SAMA B04 (bounding the potential impact of adding a dedicated station blackout diesel generator) would have the effect of reducing these scenarios. SAMA B04 was found not to be cost effective.

SAMA G04 sought to examine if improved procedures associated with, among other actions, aligning swing pumps to the EECW headers would be cost effective. SAMA G04 was determined not to be cost effective.

For three unit operation, the success criterion for EECW remains at two pumps operating. The return to service of Unit 1 will not significantly increase the risk importance of EECW.

RHRSW success criteria require one RHRSW pump to be providing flow to an RHR heat exchanger for each unit on RHR cooling. For multiple unit events, therefore, three unit operation would require three RHRSW pumps being operational. The Unit 2 and Unit 3 PRAs require two RHRSW pumps for multiple unit events. It is not expected that the additional requirement of an RHRSW pump (3 of 8 versus 2 of 8) will significantly increase the risk importance of RHRSW. Experience with the Unit 1 PRA as well as sensitivity analyses varying the common cause coupling between the EECW and RHRSW pumps support this conclusion.

The last two sentences in the response to RAI-I 3 are intended to summarize the potential impact on Turbine Building Flood initiating event (FLTB2 and FLTB) contributions to CDF due to multi-unit operation. The second to last sentence states that for small turbine building floods (FLTB2), the impact on the non-flooded units is bounded by a 6% increase in the frequency of inadvertent scram.

The last sentence states that, due to the reduction in the large turbine flood initiating event frequency (and resulting CDF) since the development of the multi-unit PRA, applying the factor of 5.5 (the ratio of the multi-unit PRA flooding CDF to the Rev. 1A PRA flooding CDF) to the absolute contribution to CDF from large turbine building flood events, will result in a small contribution to CDF (i.e., less than 1×10^{-7} per reactor year).

4a. In the response to RAI 4a, the total control room fire CDF is given as 3.05E-06. In addition, the impact of a redundant remote shutdown panel is given as a reduction in CDF of 2.66E-07.

a. The Safety Evaluation Report/Technical Evaluation Report (SER/TER) for the IPEEE gives a total control room fire CDF of 5.6E-06 due to the inclusion of fires in Unit 1 panels causing control room evacuation. Discuss the appropriateness of this value versus the RAI response estimate of 3.05E-06.

RESPONSE:

The screening CDF (SCDF) for control room fires from the updated FIVE analysis are summarized in the table below:

Updated Unit 2 FIVE Analysis for the Control Room	
Control Fire Scenario	**Screening CDF (per year)**
Unsuppressed fire in a Critical Cabinet (Panel 2-9-3) – Control Room Evacuation	7.38E-07
Suppressed fire in a Critical Cabinet (Panel 2-9-3) - MSIV closure, RCIC unavailable, and stuck open relief valve.	3.43E-09
Unsuppressed fire in Non-Critical Cabinets – Control Room Evacuation	4.18E-06
Suppressed fire in Non-Critical Cabinets - damage to the BOP panels	9.12E-08
Unsuppressed fire in a Unit 1 panel – Control Room Evacuation	4.92E-06
Total	**9.93E-06**

In this updated control room fire analysis, it was assumed that all fires cause a plant trip; and for an unsuppressed fire in a cabinet, evacuation of the control room is required. Core damage was assumed to occur if the remote shutdown capability is lost. The total updated control room fire frequency used in the analysis is 2.26E-02.

b. The reduction in control room fire CDF due to a redundant remote shutdown panel is less than 10%. Explain how this was determined. Why is it so small?

RESPONSE:

The reduction in the control room fire SCDF was re-evaluated using the EPU PSA model. A form, fit and function backup control room would essentially eliminate the SCDF contribution from control room fire scenarios due to unsuppressed fire at either a Unit 2 cabinet or a Unit 1 cabinet. By implementing this SAMA the mean SCDF for Unit 2 is estimated to be reduced by about 9.83E-06. For this evaluation, it is assumed that the impact on the plant due to a fire in the control room is similar to that of the General Transient initiating event. The results are shown in the table below.

UNIT 2 AND UNIT 3 SAMA FOR CONTROL ROOM RESULTS

MAAP Case	Unit 2	Unit 3
MIA	7.75E-06	3.69E-06
MKC	2.10E-10	1.19E-09
NIH	3.75E-08	1.07E-08
OIA	0.0	0.0
PID	0.0	0.0
PIH	0.0	0.0
PJH	0.0	0.0
PLF	2.05E-06	1.20E-06
Reduction in Person-rem	3.550	1.775
SAMA Saving (3%)	$760,068	$379,414
SAMA Saving (7%)	$478,862	$239,072

The maximum cost avoidance for the impact of three-unit operation is $1.1M. Note that the impact of uncertainty is already factored into the estimate of the cost avoidance by assuming the SCDF value is the mean CDF value. The Unit 2 control room fire induced SCDF accounts for fire events in Unit 1 control room panel that requires room evacuation. The implementation cost of this SAMA which essentially involves the reproduction of the MCR in fit, form and function is estimated to be in excess of $5M/unit. The cost avoidance is less than the total cost of a redundant remote control room – one for each unit.

c. **Are there any less extensive candidate SAMAs that would impact the fire risk than a redundant remote shutdown panel?**

RESPONSE:

No less extensive candidate SAMA was identified that would impact the fire risk from a main control room fire. The control room fire scenarios of interest all result in the abandonment of the main control room. The logical SAMA that potentially could reduce the screening CDF for these scenarios is the provision of a form, fit, and function backup control room such that operator access to all available systems is provided. This backup control room must be totally independent of the existing main control room.

5a/b. The fire CDF is estimated at 9.8E-6 for Unit 2 in the BFNP IPEEE and 1.24E-05 in the SER/TER. The Unit 2 fire IPEEE utilizes the IPE/PRA, Rev. 1 for the quantitative portion of the analysis. What is the total CDF for this revision of the internal events PRA? Similarly, for the Unit 3 fire IPEEE, a version of the above Unit 2 IPE/PRA, Rev. 1 was used for the quantitative portion of the analysis. What is the internal events CDF for the PRA used in the Unit 3 fire IPEEE?

RESPONSE:

The PSA model used in the current Unit 2 FIVE analysis was Unit 2 PSA Rev 0 (2002) and has a mean CDF for internal events of 1.3E-06.

The PSA model used in the current Unit 3 FIVE analysis was PSA model U3051602 and has a mean CDF for internal events of 1.9E-06.

6. **Uncertainty for ATWS sequences could be greater than the factor of 3 considered, and perhaps as high as a factor of 10. If this broader uncertainty range were considered, SAMA BO6 might be cost beneficial. Discuss whether consideration of a broader uncertainty range would impact the conclusion regarding ATWS-related SAMAs.**

RESPONSE:

The frequency distributions for ATWS sequences were determined for Unit 2 and Unit 3. These distributions were determined to have the following characteristics:

Unit	Frequency of ATWS Sequences (per year)			
	5th % ile	Median	Mean	95th % ile
Unit 2	2.13 E-8	1.12 E-7	2.01 E-7	6.53 E-7
Unit 3	2.34 E-8	1.24 E-7	2.11 E-7	6.58 E-7

The measure used to indicate uncertainty was the ratio of the 95th percentile to the mean. For ATWS sequences, this ratio is 3.2 and 3.1 for Units 2 and 3, respectively. Note that for these distributions, the mean is approximately the 70th percentile. These values are only slightly higher than the corresponding measures for all sequences reported in the original submittal (3.2 and 2.8). In the original assessment, a factor of 3 was used to bound the potential impact of uncertainty.

Using a value of 3.2 to represent the potential impact of uncertainty, SAMA B06 is re-evaluated with the following results:

Candidate SAMA	SAMA Title	Estimated Cost (2016)	Maximum Cost Avoidance (Base Case)	Screening Cost for Impact of Uncertainty	Screening Cost Avoidance for Impact of Three-Unit Operation	Screening Cost Avoidance for Impact of both Uncertainty and Three-Unit Operation	Cost Effective?
B06	Automatic Initiation Of SLC (ATWS)	$623K/unit	$44 K/unit	$141 K/unit	$440 K/plant	$1.4 M/plant	N

Part II. Additional questions.

1. **In response to an informal staff request, TVA provided electronic versions of the Unit 2 Summary Report, Revision 1, January 2003, and the Unit 3 Summary Report, Revision 1, January 2003, as referenced in the Environmental Report. The CDF in the Unit 2 report is 2.7E-6 per year. In response to RAI 1.c, TVA mentions PSA summary reports dated February 2004, and which provide a Unit 2 CDF of 2.6E-6 per year. Please address this discrepancy, and provide any later documents. NOTE – PER A TELECON HELD 8/25/04 BETWEEN NRC AND TVA, NRC requested information regarding the unit 1 PSA.**

RESPONSE:

Revision 2 of the Unit 1, Unit 2, and Unit 3 Summary Reports have been issued and are attached.

The mean core damage frequency reported in Revision 2 of the Unit 1 Summary Report is 1.86 E-6 per year. The initial conditions of the Unit 1 PRA model are with Unit 1 operating at EPU power with Units 2 and 3 in service at EPU operating conditions. This compares to the assumed core damage frequency used in the SAMA analysis of 10.48 E-6 (four times the nominal Unit 2 base case of 2.62 E-6). The results of the recently completed Unit 1 PRA model are evidence that the simple multiplicative factor used in the SAMA screening process is very conservative.

All aspects of the Unit 1 model reflect the impact of operation of all three units at EPU conditions. For example, the frequency of occurrence of floods in the turbine building was increased to reflect the initial condition of three units in service. System models were developed to properly reflect shared equipment (such as the cross connections between RHR divisions of adjacent units).

2. **In the NRC assessment of SAMAs for BFNP, we have made some alternative assumptions regarding benefits in external events, and as a result, have identified 7 SAMAs that are within a factor of 3 of being cost beneficial (this factor relates to the uncertainty). These SAMAs are:**

    B01 - Automate depressurization
    B06 - Automate SLC initiation
    B11 - Improve DC reliability
    G04 - Enhance ability to cross-tie service water
    G12c - Add redundant DC control power
    G17 - Procedure to trip unneeded RHR/CS pumps on loss of room ventilation
    SAMA from RAI 12g - Procedure to align LPCI or core spray to the CST

Provide additional information to justify why these SAMAs should not be implemented. This could include more realistic estimates of: implementation costs, risk reduction (in internal events), risk reduction in external events, or other factors such as operational considerations. NOTE – PER A TELECON HELD 8/25/04 BETWEEN NRC AND TVA, NRC deleted B01 and B06 from the list of SAMAs to be investigated.

B11: Improve DC reliability

The bounding model used to evaluate SAMA B11 set the unavailabilities of the three battery boards to zero. In other words, the bounding model assumed that the batteries are available 100% of the time and are fault free. The assessment of this SAMA also assumes that this improved level of performance can be achieved by procedural improvements, a relatively low cost option. Clearly the potential benefit is overstated and at the same time the potential costs are understated.

An engineering analysis would be necessary to determine the improvement in unavailability, if any, that might be possible from only improving procedures. For this screening analysis, it is assumed that a 20% improvement is achievable with improved procedures. The cost avoided therefore would be approximately 20% of the value presented in table VIII-1. The screening value approximating the impact of three unit operation (which conservatively assumes the CDF of units one and two are each four times the base value for unit 2) and uncertainty becomes $26K/plant. The potential SAMA remains screened as not cost effective.

G04 - Enhance ability to cross-tie service water

The bounding model to reflect the potential benefit of this SAMA includes both procedural improvements (align swing pumps to EECW service) and hardware changes (RCW is assumed to be cross-tied with RBCCW in the model). In addition, the frequency of the Loss of RBCCW initiator is assumed to be zero (this initiator is assumed to represent zero risk). The cost used in the screening assessment assumed only the costs associated with procedural improvements, thereby underestimating the total implementation costs. The actions necessary to align the swing pumps are assumed in the analysis to occur without error. Clearly the potential benefit is overstated and at the same time the potential costs are understated.

Consideration of the additional costs of the hardware changes necessary to accomplish this SAMA increases the estimate to $150k/unit. This results in an increase of $77K/unit. This increase is a conservative lower bound on the engineering analyses, licensing review and hardware changes necessary. The SAMA is screened as it is not cost effective.

G12c - Add redundant DC control power

The bounding model developed to address this SAMA included the addition of redundant DC power that also assumed that charging is always available to extend the life of the batteries. As previously discussed, this model includes the assumption that if HPCI or RCIC maintain level for 6 hours, then the scenario is successfully terminated. A more realistic, but still bounding, model was developed that focused directly on improved DC reliability. In this model, the reliability of every battery was assumed to be increased as a result of the addition of redundant DC control power. (The unavailability of each battery was assumed to decrease by a factor of 2). The rules defining successful scenario termination developed in the base case were used in this updated model.

The results are a 2% decrease in CDF for Unit 2 and a 1% decrease in CDF for Unit 3. The cost avoided for Unit 2 is \$5486 (3%) and \$3497 (7%). For Unit 3, the cost avoided is \$2001 (3%) and \$1282 (7%).

The maximum cost avoidance is therefore \$5486/unit; the screening cost for the impact of uncertainty is \$16.5K/unit; and, the screening cost avoidance for the impact of three-unit operation is \$47.9K/plant. The screening cost avoidance accounting for both uncertainty and three-unit operation is \$144K/plant. The SAMA is not cost effective even at the elevated screening value of 2 x \$144k/plant.

G17 - Procedure to trip unneeded RHR/CS pumps on loss of room ventilation

The model developed to bound the potential impact of this SAMA assumed that the unavailability of the RHR and CS pumps would decrease by 20% if dependence on room ventilation could be removed. The 20% value was derived from a review of the system analyses; ventilation failure contributed approximately 20% to the unavailability of the RHR and CS pumps. No engineering analyses were conducted to support the assumption that environmental conditions would remain within pump operability limits if the "unneeded pumps" were tripped. Such analyses are necessary if consideration of procedures to trip pumps are to be further considered. (The development and implementation of ineffective procedures may divert resources needed otherwise in the response to an event.) The cost of such analyses was not included in the original cost estimate. Local area temperature time histories would be required for the RHR and CS pump locations for a spectrum of initial conditions. These analyses are highly specialized and complex and would have to be conducted for all three units. The 2003 conservative cost estimate to perform such analyses, including the determination of the necessary pump thermal fragility information, is \$75K/unit. In 2016 dollars the analysis cost is estimated to be \$110K/unit. The total estimated implementation cost is therefore \$549K/plant.

This SAMA is not cost effective even assuming 2x the calculated avoided cost.

SAMA from RAI 12g - Procedure to align LPCI or core spray to the CST

SAMG-1 already includes guidance for use of LPCI or Core Spray from the CST. These procedures are in place at Browns Ferry, but are not represented in the PRA.

Adapted From Table VIII -1
EVALUATION OF PHASE II SAMAs

Candidate SAMA	SAMA Title	Revised Estimated Implementation Cost (2016)	Maximum Cost Avoidance (Base Case)	Revised Screening Cost for Impact of Uncertainty	Revised Screening Cost Avoidance for Impact of Three-Unit Operation	Revised Screening Cost Avoidance for Impact of both Uncertainty and Three-Unit Operation	Revised Sensitivity Case: Screening Cost times 2	Cost Effective?
B11	Improve DC Reliability	$73K/unit	$0.9K/unit	$2.6K/unit	$8.5K/plant	$26K/plant	$52K/plant	N
G04	Procedural guidance for use of cross-tied component cooling or service water pumps.	$150K/unit	$6.5K/unit	$19.5K/unit	$57.8K/plant	$173K/plant	$346/plant	N
G12c	Add redundant DC Control Power	$1.5M/plant	$5.5K/unit	$16.5K/unit	$47.9k/plant	$144K/plant	$288K/plant	N
G17	Procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	$183K/unit	$5.6K/unit	$16.8K/unit	$55.2K/plant	$165.6K/plant	$331.2K/plant	N
SAMA from RAI 12g	Develop procedures to align LPCI or Core Spray to the CST on loss of suppression pool cooling	N/A	N/A	N/A	N/A	N/A	N/A	N

3. **Please provide an explanation of the methods and assumptions used to estimate the projected population within 50 miles input to the MACCS calculations. The ER only provides a reference to a TVA calculation.**

RESPONSE:

The population data for the years 1990 and 2000 was determined using US Census Bureau data. The population for 2036 was extrapolated based on the 1990 and 2000 population data. In sectors with positive growth rate, the growth was linearly extrapolated. Sectors with a negative growth rate were conservatively estimated to have the same population in 2036 as they had in 2000.

4. **Please provide an explanation of the methods and assumptions used to develop the economic data input to the MACCS calculations (e.g., land values within the 50 mile region). Also provide a table showing the economic impact of each release category as predicted by MACCS and used to develop the values for "Sum of Annual Economic Risk" in ER Table IV-2.**

RESPONSE:

There are four categories of land values required in the site data file: the fraction of land devoted to farming, the fraction of farm sales that come from dairy products, the annual sales of farm products, and the property value of farm land. These are tabulated on a state-by-state basis. Each sector is assigned to the state in which it lies (or predominantly lies, if it is on a border), and the values for the state assigned are used to compute property damage in that sector.

The values of farm real estate, including value of land and buildings per acre, farm acreage, milk produced on farms, and value of production, were taken from Table 1105 on the CD Version of the Statistical Abstracts of the United States, 1998, published by the U. S. Department of Commerce, Economics and Statistics Administration, Bureau of the Census. The area of land and water of states and other information was taken from Table 387 on the same CD. The latest year for which all data were available was 1996, so that was the year that was used as the base year. The farm fraction was determined for each state by multiplying the farm acreage in thousands from Table 1105 by 0.640 (there are 640 acres in a square mile) and the result is divided by the land area of that state from table 387 to get the farm fraction for that state. The value of milk production from Table 1105 was divided by the value of total farm production from Table 1105 to determine the fraction of farm sales that come from dairy products. The value of total farm production from Table 1105 was multiplied by 2471.0538 hectares per thousand acres and divided by the farm acreage in thousands from Table 1105 to give the annual farm sales in 1996. This value was multiplied by the inflation adjustment factor of 3.306473 (the actual CPI increase from 1996 to 2000, plus 7% assumed inflation from 2000 to 2016) to give the annual farm sales projected to 2016. The value of land and buildings per acre from Table 1105 was multiplied by 2471.0538 and divided by the farm acreage in thousands from Table 1105 to give the farmland property value in 1996. This was multiplied by the inflation adjustment factor of 3.306473 to give the farmland property value projected to 2016. The process was repeated for the 3% data, but using 3% inflation from 2000 to 2016.

Table 4-a. REGIONAL ECONOMIC DATA Inflated to 2016 at 7% after 2000

Region Number	Region Name	Fraction of Land Devoted to Farming	Dairy Fraction of Farm Sales	Annual Farm Sales, $/hectare	Farmland Property Value, $/hectare
1	ALA	0.124	0.022	2645.89	11333.82
40	TENN	0.183	0.108	1642.32	12467.92

Table 4-b. REGIONAL ECONOMIC DATA Inflated to 2016 at 3% after 2000

Region Number	Region Name	Fraction of Land Devoted to Farming	Dairy Fraction of Farm Sales	Annual Farm Sales, $/hectare	Farmland Property Value, $/hectare
1	ALA	0.124	0.022	1438.23	6160.72
40	TENN	0.183	0.108	892.71	6777.18

The following is a table of the unweighted economic impact of each release category at a 7% discount rate.

Economic Cost Breakdown for Each Plant Damage State, 2016 Dollars (at a 7% Discount Rate)

Key Plant Damage State	MKC	MIA	NIH	OIA	PID	PIH	PJH	PLF
MAAP Case	ENMKCTT	MIALF	NIH	OIA	PID	PIHDEP	PJH	PLF
Population Decontamination	5.13E+09	5.46E+07	3.08E+08	3.26E+09	3.04E+06	4.12E+09	1.77E+07	4.54E+07
Population Interdiction	1.06E+10	1.16E+08	6.31E+08	7.04E+09	6.54E+06	7.60E+09	4.04E+07	9.92E+07
Population Condemnation	1.27E+07	2.83E+04	1.68E+05	1.05E+07	3.55E+03	5.84E+06	1.14E+04	4.90E+04
Total Population Dependent	1.73E+10	1.72E+08	9.47E+08	1.16E+10	9.59E+06	1.23E+10	5.83E+07	1.45E+08
Farm Decontamination	1.41E+08	1.75E+06	8.35E+06	9.19E+07	2.15E+05	1.12E+08	6.97E+05	1.68E+06
Farm Interdiction	1.13E+08	4.91E+06	1.55E+07	6.90E+07	6.20E+05	9.14E+07	1.82E+06	4.99E+06
Farm Condemnation	1.58E+09	1.25E+06	7.01E+06	1.33E+09	1.45E+03	5.64E+08	1.33E+05	6.11E+05
Farm Dependent	3.99E+08	1.33E+07	4.28E+07	2.50E+08	1.77E+06	3.20E+08	5.12E+06	1.41E+07
Emergency Phase	5.51E+07	1.57E+05	2.15E+05	2.31E+07	1.50E+04	2.61E+07	2.52E+04	1.63E+05
Milk Disposal	1.48E+06	3.65E+04	2.20E+05	8.87E+05	6.83E+03	1.25E+06	2.10E+04	5.36E+04
Crop Disposal	1.31E+08	6.57E+06	1.86E+07	7.75E+07	9.28E+05	1.10E+08	2.57E+06	7.33E+06
Total	1.77E+10	1.85E+08	9.89E+08	1.19E+10	1.14E+07	1.26E+10	6.34E+07	1.59E+08

The following is a table of the unweighted economic impact of each release category at a 3% discount rate.

Economic Cost Breakdown for Each Plant Damage State, 2016 Dollars (at a 3% Discount Rate)

Key Plant Damage State	MKC	MIA	NIH	OIA	PID	PIH	PJH	PLF
MAAP Case	ENMKCTT	MIALF	NIH	OIA	PID	PIHDEP	PJH	PLF
Population Decontamination	2.79E+09	2.97E+07	1.67E+08	1.77E+09	1.65E+06	2.24E+09	9.63E+06	2.47E+07
Population Interdiction	5.74E+09	6.28E+07	3.43E+08	3.83E+09	3.55E+06	4.13E+09	2.20E+07	5.39E+07
Population Condemnation	6.89E+06	1.54E+04	9.12E+04	5.73E+06	1.93E+03	3.17E+06	6.20E+03	2.66E+04
Total Population Dependent	9.41E+09	9.33E+07	5.15E+08	6.33E+09	5.21E+06	6.70E+09	3.17E+07	7.90E+07
Farm Decontamination	7.66E+07	9.53E+05	4.54E+06	5.00E+07	1.17E+05	6.08E+07	3.79E+05	9.14E+05
Farm Interdiction	6.17E+07	2.67E+06	8.40E+06	3.75E+07	3.37E+05	4.97E+07	9.89E+05	2.71E+06
Farm Condemnation	8.56E+08	6.78E+05	3.81E+06	7.21E+08	7.88E+02	3.07E+08	7.24E+04	3.32E+05
Farm Dependent	2.17E+08	7.23E+06	2.33E+07	1.36E+08	9.64E+05	1.74E+08	2.78E+06	7.67E+06
Emergency Phase	3.00E+07	8.51E+04	1.17E+05	1.26E+07	8.13E+03	1.42E+07	1.37E+04	8.88E+04
Milk Disposal	8.06E+05	1.98E+04	1.20E+05	4.82E+05	3.71E+03	6.81E+05	1.14E+04	2.91E+04
Crop Disposal	7.10E+07	3.57E+06	1.01E+07	4.21E+07	5.04E+05	5.96E+07	1.40E+06	3.99E+06
Total	9.63E+09	1.01E+08	5.38E+08	6.47E+09	6.18E+06	6.87E+09	3.45E+07	8.67E+07

5. **NOTE – PER A TELECON HELD 8/25/04 BETWEEN NRC AND TVA, NRC requested the following information. Provide the conditional core damage frequency for a Loss of Offsite Power initiating event for units 2 and 3, with no offsite power recovery. Using an initiating event frequency of 5 E-5/year provide a discussion regarding the impact of seismically-induced LOOP upon plant risk and the SAMA analysis.**

The Loss of Offsite Power transient models were modified and re-quantified. The modifications made to the models were:

- The frequency of loss of offsite power was set to 5 E-5
- No recovery of the offsite grid was credited (i.e., top events associated with grid recovery at 30 minutes and 6 hours were set to "guaranteed failed.")

The core damage frequency calculated for this initiator is 1.64 E-8 and 3.66 E-8 for Units 2 and 3, respectively. The CCDF for this initiator are therefore 3.28 E-4 and 7.32 E-4 for Units 2 and 3, respectively.

The postulated effect of this earthquake level is gross failure of switchyard and transmission grid hardware, particularly ceramic insulators. The low CDF value associated with this earthquake-induced LOOP eliminates any applicable SAMA from being cost effective.

The inclusion of this initiating event into the Unit 2 and Unit 3 PSAs would result in an increase of 0.62% for Unit 2 and 1.09% for Unit 3.