PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

10 CFR 50
10 CFR 51
10 CFR 54

MAY 24 2010

LR-N10-0164

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

Salem Nuclear Generating Station Units 1 and 2
Facility Operating License Nos. DPR – 70 and DPR – 75
NRC Docket Nos. 50-272 and 50-311

Subject: Response to NRC Request for Additional Information dated April 12, 2010, related to the Severe Accident Mitigation Alternatives (SAMA) review of the Salem Nuclear Generating Station, Units 1 and 2.

References: Letter from Mr. Charles Eccleston (USNRC) to Mr. Thomas Joyce (PSEG Nuclear, LLC) "REQUEST FOR ADDITIONAL INFORMATION REGARDING SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2", dated April 12, 2010

In the referenced letter, the staff requested additional information related to the Severe Accident Mitigation Alternatives (SAMA) analysis contained in the Salem Generating Station, Units 1 and 2 License Renewal Application (LRA). Enclosed are the responses to this request for additional information.

This letter and its enclosure contain no commitments.

If you have any questions, please contact Ed Keating, Senior Environmental Advisor, PSEG Nuclear at 856-339-7902.

A001
NRR

MAY 24 2010

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

Executed on: 5-24-2010

Sincerely,

Paul J. Davison

Paul J. Davison
Vice President, Operations Support
PSEG Nuclear LLC

Enclosure : Response to Request for Additional Information

cc: S. Collins, Regional Administrator – USNRC Region I (w/o enclosure)
C. Eccleston, Environmental Project Manager, License Renewal – USNRC (w/ enclosure)
R. Ennis, Project Manager – USNRC (w/o enclosure)
NRC Senior Resident Inspector – Salem (w/o enclosure)
P. Mulligan, Manager IV, NJBNE (w/ enclosure)
L. Marabella, Corporate Commitment Tracking Coordinator (w/o enclosure)
Howard Berrick, Salem Commitment Tracking Coordinator (w/ enclosure)
T. Devik, Hope Creek Commitment Tracking Coordinator (w/o enclosure)

ACRONYMS AND ABREVIATIONS

ACRONYM OR ABREVIATION	RAI #	DEFINITION
AC	1.a	alternating current
AFW	1.a	auxiliary feed water
AFWST	5.b, Table 5b-2a	auxiliary feed water storage tank
AMSAC	1.a	anticipated transient without scram (ATWS) mitigation system actuation circuitry
AMSAC	5.b, Table 5b-2a	ATWS mitigation system actuation circuitry
ATWS	1.e, Table 2	anticipated transient without scram
BMMT	5.b, Table 5b-1	basemat melt through
CAV	5.b, Table 5b-2a	control area ventilation
CCF	5.b, Table 5b-2a	common cause factor
CCPS	5.b, Table 5b-2a	component cooling pumps
CCS	1.a	component cooling system
CCS	5.b, Table 5b-2a	component cooling system
CCW	5.b, Table 5b-2a	component cooling water (same as CCS)
CDC	3.d	certain dangerous cargo
CDE	1.c, Table 1	comprehensive data entry
CDF	1.a	core damage frequency
CET	2.c	containment event tree
CFCU	2.c	containment fan cooler unit
CFE	2.f	early containment failure
CFR	3.d	Code of Federal Regulations
CHG	5.b, Table 5b-2a	charging system
CHR	5.b, Table 5b-1	containment heat removal
COTP	3.d	Captain of the Port
CS	2.c	containment spray
CVC	5.b, Table 5b-2a	chemical volume and control system
DC	1.a	direct current

ACRONYMS AND ABREVIATIONS		
ACRONYM OR ABREVIATION	**RAI #**	**DEFINITION**
DE	4.a	Delaware
DEP	5.b, Table 5b-2a	dependent
DG	5.b, Table 5b-2a	diesel generator
DGN	5.b, Table 5b-2a	diesel generator
E	4.a	east
ECCS	6.b	emergency core cooling system
EDG	1.a	emergency diesel generator
ENE	4.a	east-north-east
EOP	6.e	emergency operating procedure
EPIX	1.c, Table 1	Equipment Performance and Information Exchange
ER	5.a	[license renewal] environmental report
ESE	4.a	east-south-east
ESF	1.d	engineered safety features
FERC	3.d	Federal Energy Regulatory Commission
FICR	5.b, Table 5b-2a	fire inside control room
FTR	5.b, Table 5b-2a	fail to run
F-V	1.e	Fussell-Vesely
FW	5.b, Table 5b-2a	feedwater
GTG	5.b, Table 5b-2a	gas turbine generator
HDR	5.b, Table 5b-2a	header
HFE	1.a	human failure event
HRA	1.a	human reliability analysis
HRS	5.b, Table 5b-2a	hours
HVAC	1.e, Table 2	heating, ventilation and air conditioning
IE-TCA	5.b, Table 5b-2a	loss of control air initiating event
IE-TCC	1.e, Table 2	loss of component cooling system initiator

ACRONYMS AND ABREVIATIONS		
ACRONYM OR ABREVIATION	**RAI #**	**DEFINITION**
IE-TSW	1.e, Table 2	insufficient flow to both service water headers initiator
IE-TVC	1.e, Table 2	loss of control area heating and ventilation initiator
IMO	3.d	International Maritime Organization
IPE	1.a	individual plant examination
IPEEE	1.a	individual plant examination of external events
ISLOCA	1.a	interfacing system loss of coolant accident (LOCA)
K	6.c	thousand
KV	5.b, Table 5b-2a	kilovolts
LERF	1.a	large, early release fraction [or frequency]
LLC	3.d	Limited Liability Company
LNG	3.d	liquefied natural gas
LOOP	1.a	loss of offsite power
LOR	3.d	Letter of Recommendation
LRA	3.b	License Renewal Application
LRR	3.b	low ruggedness relay
M	6.h	million
m^3	3.d	cubic meters
MAAP	2.e	Modular Accident Analysis Program
MACCS2	4.c	MELCOR Accident Consequence Code System for the Calculation of the Health and Economic Consequences of Accidental Atmospheric Radiological Releases
MACR	6.k	maximum averted cost risk
MCR	5.b, Table 5b-2a	main control room
MD	4.a	Maryland
MFW	5.b, Table 5b-2a	main feedwater
MOR	1.c	model of record
MOV	1.c, Table 1	motor operated valve
MSPI	1.c, Table 1	mitigating systems performance index
MWe	2.g	megawatts (electric)

ACRONYMS AND ABREVIATIONS		
ACRONYM OR ABREVIATION	**RAI #**	**DEFINITION**
MWt	2.g	megawatts (thermal)
N	4.a	north
NE	4.a	north-east
NJ	3.d	New Jersey
NNE	4.a	north-north-east
NNW	4.a	north-north-west
NW	4.a	north-west
OECR	2.f	offsite economic cost risk
PA	4.a	Pennsylvania
PACR	3.a	partial averted cost-risk
PCS	1.a	power conversion system
PCS	1.e, Table 2	process control system
PDP	1.a	positive displacement pump
PDR	4.a	person-dose risk
PDS	2.d	plant damage state
PHC	7.a	Plant Health Committee
plt	5.b, Table 5b-2a	plant
PORV	1.a	power operated relief valve
PORVs	1.a	power operated relief valves
PRA	1.a	probabilistic risk assessment
PSA	1.d	probabilistic safety assessment
PWR	1.c	pressurized water reactor
PWROG	1.c	Pressurized Water Reactor Owners Group
RAI	4.c	request for additional information
RCP	1.a	reactor coolant pump
RCS	2.c	reactor coolant system
RCS-SLOCA-SPLIT	1.a	reactor coolant system – small-break loss of coolant accident – conditional split fractions (failure probabilities)

ACRONYMS AND ABREVIATIONS		
ACRONYM OR ABREVIATION	**RAI #**	**DEFINITION**
RHR	1.a	residual heat removal
RPS	5.b, Table 5b-2a	reactor protection system
RRW	5.b	risk reduction worth
RWST	1.a	refueling water storage tank
RX	5.b, Table 5b-2a	reactor
S	4.a	south
SAMA	1.b	severe accident mitigation alternative
SBO	1.a	station black-out
SDP	5.b, Table 5b-2a	shutdown panel
SE	4.a	south-east
SER	3.b	safety evaluation report
SG	1.a	steam generator
SG	5.b, Table 5b-2a	steam generator
SGS	1.c, Table 1	Salem Generating Station
SGTR	5.b, Table 5b-1	steam generator tube rupture
SOLAS	3.d	International Convention for the Safety of Life at Sea
SSE	4.a	south-south-east
SSW	4.a	south-south-west
SW	1.c, Table 1	service water
SW	4.a	south-west
SWGR	5.b, Table 5b-2a	switchgear
swyd	5.b, Table 5b-2a	switchyard
TDAFW	5.b, Table 5b-2a	turbine-driven auxiliary feedwater pump
TDE	5.b, Table 5b-2a	particular station blackout sequence
TDP	5.b, Table 5b-2a	turbine-driven pump
TM	5.b, Table 5b-2a	test and maintenance
TNC	5.b, Table 5b-2a	transient event without loss of offsite power followed by loss of control area ventilation initiator
V	6b	volts

ACRONYMS AND ABREVIATIONS		
ACRONYM OR ABREVIATION	**RAI #**	**DEFINITION**
VCA	5.b, Table 5b-2a	ventilation control area (same as CAV)
VCT	1.a	volume control tank
VSW	5.b, Table 5b-2a	switchgear heating and ventilation
W	4.a	west
W/I	5.b, Table 5b-2a	within
WNW	4.a	west-north-west
WSW	4.a	west-south-west

RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION (RAIs)

1. Provide the following information regarding the Level 1 Probabilistic Safety Assessment (PSA) used for the Severe Accident Mitigation Alternatives (SAMA) analysis:

1.a Section E.2.1 provides varying levels of detail describing the PSA model changes made since the IPE Level 1 model. For PRA Model Versions 2.0 and 3.0, provide additional description of the model changes that most impacted the change in core damage frequency (CDF). For PRA Model Versions 3.2, 3.2A, and 4.0, identify the model changes listed in Section E.2.1 that most impacted the change in CDF.

PSEG Response:

Changes to the Salem PRA model between the time of the IPE and model version 2.0 included enhancements to the service water system model, addition of AMSAC, addition of valves to the containment isolation system, elimination of switchgear ventilation as a support system, enhancement of the RCP seal model, and integration of the logic for ISLOCA into the base model. Plant data were updated and common-cause failure data were also updated. While these changes may have affected CDF, no quantitative assessment was made regarding the nature of such changes.

Revision 3 of the Salem PRA model again included switchgear ventilation as a support system. A LERF model based on NUREG/CR-6595 was developed. HRA dependency issues were addressed. Common-cause data calculations were updated. Initiating event fault tree logic was adjusted to reflect annual frequency of occurrence. Recovery credit was altered, in some cases removed. Offsite power recovery likelihood was changed to reflect that recovery after 4 hours would not be possible. While these changes may have affected CDF, no quantitative assessment was made regarding the nature of such changes.

With respect to version 3.2, existing documentation indicates that modeling of internal flooding was enhanced, resulting in changes to results. The containment isolation model was revised to remove pathways in which an isolation failure could not lead to LERF. With respect to the model changes listed in section E.2.1 and their potential impact on CDF:

> It is not expected that a software change would result in a significant change to CDF, nor would a change in the LERF model. Changes to the switchyard model could have a modest impact on CDF. Changes involving crediting a service water crosstie between units could have a measurable effect on CDF. Resolution of "B" level peer review comments involving issues such as common-cause modeling could, by definition, have an impact on CDF. Reference to the Salem IPEEE and studies involving external event risks for other plants suggests that quantitative measures of fire risk and seismic risk could be non-negligible, however

the referenced efforts were never completed for Salem. Model enhancements relating to offsite power recovery and AFW pump failure rates may have had some effect on CDF, a comparison of available information shows some decrease in CDF relating to loss of offsite power.

With respect to the model changes listed in section E.2.1 for version 3.2a and their potential impact on CDF:

Removal of gates not pertaining to CDF should have no effect on CDF. Elimination of a recovery from loss of switchgear ventilation could be expected to increase CDF somewhat. Correcting (removing) PCS recovery for loss of PCS initiators which ultimately result in LOOP should increase CDF by a small amount. Removing credit for the PDP charging pump inter-unit crosstie should result in a small increase in CDF. Removal of credit for crosstying DC power supplies to PORVs should result in an increase in CDF. Removal of credit for crosstying diesel fuel oil transfer pumps should result in a measurable increase in CDF. Relocation of a recovery credit relating to service water should not affect CDF. Changing the probability of RCS-SLOCA-SPLIT from 0.25 to 1.0, thereby making it a flag, should result in a measurable increase in CDF. Removing credit for repair of failed EDGs should result in a measurable increase in CDF. Reducing credit for the gas turbine generator as an additional source of AC power should result in a measurable increase in CDF. Removing cutsets involving RHR pump 11 and CC HX 12 (and vice-versa), which are indicated to be impermissible combinations should have the effect of slightly reducing CDF, by removing some inappropriate contributors to it. It is expected that replacing two actions to resupply suction inventory to AFW with a single action would increase CDF. Removal of use of the adjacent unit's PDP charging pump as a source of aux spray should have a minimal effect on CDF. Changing the loss of DC power initiating event frequency could have some effect on CDF. A number of HFE probabilities for operator actions thought to have insufficient procedural basis or otherwise thought to have insufficient justification were changed. Since most of the HFE probability revisions were in a higher /more conservative direction, it is expected the net effect would be to result in a measurable increase in CDF. Reducing credit for use of a condensate pump for SG makeup should result in an increase in CDF. Adding a new failure mode for CCS would be expected to result in an increase in CDF. Changing basic events which were set to 1.0 to "True" should not have an impact on CDF. Changing the description of an event should not affect CDF. Changing events with probabilities set to 0.0 to "False" should not have an effect on CDF. Reducing credit for the gas turbine should have the effect of increasing CDF. Reducing credit for an action to preserve service water availability should have the effect of increasing CDF. Reducing credit for switching from the VCT to the RWST when required should have the effect of increasing CDF. Increasing the recovery time assumed for offsite power recovery values "RBU1" and "RBU4" should have the effect of making the recoveries more effective, and thereby reducing CDF. Recovering cutsets involving failure of SW26 to close should have the effect of reducing CDF. Increasing the likelihood of a stuck open PORV in SBO sequences would have the effect of increasing CDF. Stuck open PORV logic was revised, with discussion provided about that change implying that it may not be very significant. Adding loss of CCS and failure to swap charging suction to the RWST as a new failure mode should have the effect of increasing CDF. Changing the split fractions in service water logic relating to time spent in warm weather and time spent in cool weather should have the effect of reducing CDF.

With respect to model changes made to create version 4.0:

Revisions to the human reliability analysis resulted in an increase in the values for some HFEs and in a decrease in the values for other HFEs. In the aggregate, the update resulted in a decrease in CDF. Failure data and common-cause data were updated and, again, some values increased while others decreased. Overall the net effect is believed to be a decrease in CDF.

Updating initiating event frequencies had the effect of reducing CDF. Primarily this was due to improvements in the service water initiating event fault tree model which recognized various existing proceduralized capabilities to crosstie specific service water supported functions between units (e.g. cooling control area spaces on one unit via chillers from the adjacent unit, the chillers being supplied with service water from their respective unit) and which also recognized certain capabilities to replace cooling provided by service water or (service water supported) component cooling water systems (primarily alternate cooling of charging pumps). Changes to LOOP frequencies were modest and should have had a modest effect on CDF. Crediting cool-down and depressurization and transition to RHR to respond to small losses of coolant events resulted in a measurable reduction in CDF. Change in the control area ventilating system resulted in a significant increase in CDF. Some of the changes with respect to service water modeling resulted in CDF increases, while other changes resulted in decreases. On balance, the CDF contribution from the service water system was reduced. Correcting the modeling of EDG fuel oil supply resulted in a modest increase in CDF. RCP seal model changes resulted in an increase in CDF. Reducing credit for the gas turbine generator resulted in an increase in CDF. Consolidation of manual shutdown and "very small" LOCA events with transients did not result in a significant change in CDF. Changes to modeling of DC power dependencies resulted in an increase in CDF. Removal of irrelevant logic did not result in a significant change in CDF.

1.b Section E.2.1.3 explains that although early versions of the SNGS PRA modeled both Unit 1 and 2, only Unit 1 was modeled starting with PRA model of record Revision 3.0 (June 2002). Explain the differences in configuration between Units 1 and 2 and how configuration and administrative changes that could potentially produce significantly different CDFs for the two units were tracked. In the response, identify any of the Unit 2 differences that would potentially show up on the Level 1 or 2 importance lists and assess SAMAs to address these differences.

PSEG Response:

There are currently no differences between units 1 and 2 which are believed to be important from a risk perspective. Differences which are considered include: recirculation switchover on unit 1 is strictly manual, whereas on unit 2 it is "semi-automatic" (several of the switchover actions are automated but some actions are still required); and one component cooling heat exchanger on unit 1 is of a different design than its counterpart on unit 2 (plate vs. tube and shell), If a modification is implemented which makes the risk profile significantly different for one unit vs. another, this will be addressed by the PRA maintenance and update process. Revision 3 of the Salem PRA model again included switchgear ventilation as a support system. A LERF model based on NUREG/CR-6595 was developed. HRA dependency issues were addressed. Common-cause data calculations were updated. Initiating event fault tree logic was adjusted to reflect annual frequency of occurrence. Recovery credit was altered, and in some cases removed. Offsite power recovery likelihood was changed to reflect that recovery after 4 hours would not be possible.

1.c Section E.2.3 states that in November 2008 a PWR Owners group team performed a peer review of Revision 4.1, but that the peer review comments had not yet been received. It is our understanding that the peer review report is now available. Provide a summary of the scope of the peer review (e.g., Level 1, Level 2, internal flooding), a description of the significant review comments and their resolution, and an assessment of the potential impact of any unresolved comments on the results of the SAMA analysis. Describe any other internal and external reviews of the Level 1 (including internal flooding) and Level 2 PRA model, significant review comments and their resolution, and the impact of unresolved comments on the results of the SAMA analysis.

PSEG Response:

The scope of the peer review included level 1, level 2 and internal flooding. Table 1 identifies "key" findings provided in the peer review report and the associated evaluation / resolution.

TABLE 1
PEER REVIEW REPORT SUMMARY

ELEMENT	DESCRIPTION	IMPACT ON SAMA ANALYSIS
AS	The first issue was that the ISLOCA sequence with no piping failure is assumed to be terminated with operator isolation of the suction path using the pump suction isolation MOVs. However isolation cannot be accomplished until primary pressure is reduced. The potential for flooding of adjacent areas by water lost through the RHR pump seals and/or RHR heat exchangers prior to isolation does not appear to have been evaluated. The significance of this is that flooding of adjacent areas could impact additional equipment affecting the ability to achieve a safe, stable condition.	Internal flooding analysis indicates that systems credited for ISLOCA mitigation are expected to remain available given postulated volume of water released into RHR pump /heat exchanger area. No impact to application.

TABLE 1
PEER REVIEW REPORT SUMMARY

ELEMENT	DESCRIPTION	IMPACT ON SAMA ANALYSIS
DA	The second issue involved data analysis, and specifically component availability. Component availability depends on an accurate count of maintenance unavailability (DA-C11). Maintenance and testing unavailability were identified in the model. However no specific surveillance tests were discussed in the Data Analysis Notebook. MSPI/ Maintenance Rule sources were identified. The specific surveillances or plant maintenance contributing to the unavailability of plant components and the process for counting these durations should be documented in a data procedure.	Non-significant impact. The PRA data evaluation for Salem is based on MSPI and Maintenance Rule data, which is believed to be accurate. Any changes to plant-specific failure rates from a comparison of expected unavailability due to test procedures and maintenance with actual MSPI and Maintenance Rule data is expected to be non-significant.
IE	The third issue involves Initiating Events. For those initiators that are modeled using fault trees, such as SW and loss of closed cooling, the initiator frequency is not based on reactor year. For example, under gate IE-TSW, basic event SWS-PIP-RP-TBHDR has a mission time of 8760 hours. Use reactor year which considers the actual plant availability as the expected metric when quantifying the initiator frequencies.	No impact. The current treatment is very slightly conservative. Addressing the issue would only lead to a small reduction in the calculated annual CDF.
IE	The fourth issue involves initiating events. The initiating events notebook describes the review of the Salem Generating Station Experience and Trip Review. No mention is made of consideration of events that occurred at conditions other than at-power operation. Also events resulting in controlled shutdown were excluded on the basis that they present only mild challenges rather than being determined to be not applicable to at-power operation. Failure to consider non-power events and controlled shutdown events could result in exclusion of valid initiating events.	Non-significant impact. The identification of the applicable initiating events for Salem did include a review of events other than at-power operations. Events occurring during shutdowns and non-power conditions which could have occurred at power were not excluded. The SGS PRA model includes a broad range of initiating events that are sufficient for this application.

TABLE 1
PEER REVIEW REPORT SUMMARY

ELEMENT	DESCRIPTION	IMPACT ON SAMA ANALYSIS
IF	The fifth issue involves internal flooding. Flood scenarios were screened without development of flood rate, source, and operator actions. Detailed assessments were only provided for high-frequency floods. Improperly screening flood scenarios could lead to underestimating the risks associated with internal floods.	No impact. The requirements in IF-C2c and IF-C3 allow screening of flood areas. These requirements are in conflict with and therefore nullify the requirements of IF-C1, IF-C2, and IF-C2a. The treatment for Salem is consistent with what is noted in section 4.5.1 of the standard that "Some degree of event and scenario screening is typically employed in analyzing risk from internal flooding, so that although the high level and supporting requirements are written in a discrete manner, the requirements are not necessarily presented in sequential order of application and, in some cases, must be considered jointly, so that screening is performed appropriately."
AS	The sixth issue involves Accident Sequences. Specifically the SBO success paths following offsite power recovery do not address recovery and operation of required safety systems after power recovery which is considered necessary to demonstrate that a safe stable endstate has been achieved. In addition the combination of RCP seal LOCA and offsite power recovery into a single top event treatment does not provide explicit treatment of the differences in recovery time and required mitigation response for different RCP seal leakage rates. More explicit development of the SBO event sequences will ensure that they represent a safe stable end state and appropriately consider all required mitigation equipment.	Non –significant impact. The Salem offsite power recovery model considers the status of key equipment and also the potential for varying RCP seal leakage rates in determining the time available for offsite power recovery. The likelihood of LOOP, SBO, successful recovery of offsite power, then multiple equipment failures preventing long-term safe shutdown is very small. The current model provides an appropriate evaluation of risks associated with loss of offsite power events. This treatment provides a reasonable approximation of the SBO event sequence development that is sufficient for this application

TABLE 1
PEER REVIEW REPORT SUMMARY

ELEMENT	DESCRIPTION	IMPACT ON SAMA ANALYSIS
DA	The seventh issue was the omission of failure modes for the diesels due to the use of only MSPI data and not all the plant specific data. Plant-specific data is only collected for MSPI components. Documentation describing the process of collecting the number of failures, hours of operation, number of surveillance tests and planned maintenance activities on plant requirements could not be identified. Appendices to the data notebook identify data collected, but the source was often not provided. Without this source of documentation future updates could be difficult.	Non-significant impact. The PRA data evaluation for Salem is based on MSPI and Maintenance Rule data. Data from plant programs is believed to be reliable. Any changes to plant-specific failure rates from a validation of other plant specific data with what is readily available from MSPI and Maintenance Rule data is expected to be non-significant.
DA	The eighth issue was the lack of defining system boundaries. A draft document was provided that documented how to establish component boundaries, how to establish failure probabilities, sources of generic data, etc. This procedure needs to be formalized. The notebook could be improved by providing direct references to actual failure numbers in EPIX or CDE numbers in the data notebook, Appendix A. Assumptions were noted in various sections of the Data Analysis Notebook. These need to be gathered into an assumptions section in the notebook. Sources of uncertainty were not discussed in the analysis.	No impact. The issues discussed in this key finding are issues related to documentation.

There have not been any other formal reviews of the Salem internal events model since the 2008 PWROG peer review of the PRA model-of-record (MOR) Rev. 4.1. All of the peer review comments on MOR Rev. 4.1 were dispositioned, and as necessary, appropriate changes were included in subsequent PRA model revisions. For the impact of PRA model updates on the SAMA analysis, see responses to RAIs 1.d and 5.b in this enclosure.

1.d Section E.2.2 states that the PRA model of record Revision 4.1 was used for the SAMA analysis reflects SNGS plant data and incorporation of plant modifications up through December 2006. Identify any changes to the plant (physical and procedural modifications) since December 2006 that could have a significant impact on the results of the PSA and/or the SAMA analyses. Provide a qualitative assessment of their impact on the PSA and on the results of the SAMA evaluation.

PSEG Response:

Since the completion of the MOR Rev. 4.1 internal events model, one design change and one procedural change have been implemented which have resulted in potentially significant changes to PRA results. The station performed a modification to allow use of two small non-ESF diesel generators to provide power for control and operation of switchyard breakers and to provide a backup source of power to station battery chargers. This permits the station to recover from station blackout events lasting longer than the 4 hour coping period previously considered. Modeling this modification has reduced the significance of loss of offsite power sequences in the Salem PRA. The station also implemented procedural changes to address a potential loss of cooling to areas supplied by the control area ventilating system. New procedural steps direct use of a fire-response mode, "fire inside control room," which provides forced flow of large quantities of outside air in order to limit control area temperatures. As a result, loss of chillers, chilled water pumps, or support from the service water system now contributes less to core damage risk. The impacts of these changes have been incorporated into the most recent model update and the new model was used to revalidate SAMA findings (see response to SAMA 5.b).

1.e Figures E.2-1 and E.2-2 provide the contribution to CDF by Level 1 initiator. Provide a table showing the actual numerical values for the CDF contribution for each initiator that sums to the total internal events CDF (4.77 x 10-5/yr).

PSEG Response:

See Table 2, below, which lists initiating events down to F-V (fraction of total CDF) of 0.01.

TABLE 2
INITIATING EVENTS AND THEIR FUSSELL-VESELY VALUES

INITIATOR	FUSSELL VESELY	DESCRIPTION
%TVC	3.56E-01	INITIATOR FLAG FOR LOSS OF CONTROL AREA HVAC IE-TVC
%TSW	1.38E-01	INITIATOR FLAG FOR LOSS OF SERVICE WATER IE-TSW
%TES	6.89E-02	LOOP Initiator - switchyard / plant
%TEW	6.42E-02	LOOP initiator - weather
%FL_AB084C_G_SW	5.62E-02	General Flood Aux Bldg 84C Service Water
%TP	4.40E-02	TRANSIENT WITH PCS UNAVAILABLE INITIATOR
%TT	3.89E-02	TRANSIENT WITH PCS AVAILABLE INITIATOR
%TEG	3.75E-02	LOOP initiator - Grid
%TCC	2.09E-02	INIT FLAG LOSS OF COMPONENT COOLING WATER IE-TCC
%TA	1.56E-02	ATWS INITIATOR
%S4-C	1.52E-02	STEAM GENERATOR 13 TUBE RUPTURE INITIATOR
%FL_AB084B_M_FP	1.47E-02	Flood AB 084 B Major, fire protection source
%TDCA	1.45E-02	LOSS OF 125V DC BUS A INITIATOR
%S4-D	1.44E-02	STEAM GENERATOR 14 TUBE RUPTURE INITIATOR
%S4-A	1.43E-02	STEAM GENERATOR 11 TUBE RUPTURE INITIATOR
%VSW	1.38E-02	Initiator Flag for Loss of VSW IE (switchgear HVAC)
%S4-B	1.35E-02	STEAM GENERATOR 12 TUBE RUPTURE INITIATOR

TABLE 2
INITIATING EVENTS AND THEIR FUSSELL-VESELY VALUES

INITIATOR	FUSSELL VESELY	DESCRIPTION
%FL_AB084B_G_FP	1.23E-02	Flood AB 084 B General, fire protection source
%FL_AB045_SP	1.03E-02	Flood AB 045 spray all sources

1.f Provide the numerical value for the CDF contribution from SBO and identify the initiators that contribute to station blackout (SBO).

PSEG Response:

SBO sequences (loss of offsite power and failure of onsite power sources) contribute 8E-6 of the total CDF. The initiators are %TES, %TEG, and %TEW (site/switchyard-related / grid-related / weather-related LOOPs).

2. Provide the following information relative to the Level 2 analysis:

2.a Section E.2.2.2.1 states that starting with model of record Revision 3.0 (i.e., 2002) only LERF was calculated. Table E.3-7 shows non-LERF Release Categories (e.g. LATE-CHR-NOAFW) produce significant dose consequences. Describe how the frequencies for the non-LERF Release Categories were estimated in support of the SAMA analysis.

PSEG Response:

The PRA model-of-record (MOR) Revision 4.1, which was used to support the SAMA analysis, included a full Level 2 analysis, which includes both LERF and non-LERF release categories. The description in Section E.2.2.2.1 only discusses versions prior to the PRA MOR Rev. 4.1.

2.b Page E-27 states that the Salem Level 2 model was essentially abandoned and then recreated and used in PRA Model Version 4.1 for the SAMA analysis. Section E.2.2.2.1 states that starting with Revision 3 of the PRA model only LERF was calculated. Clarify the Level 2 model development history, including when (after which PRA version) the Level 2 model was abandoned, and in which PRA version the Level 2 model was recreated.

PSEG Response:

The PRA model-of-record (MOR) Revision 4.1, which was used to support the SAMA analysis, included a full Level 2 analysis, and includes both LERF and non-LERF release categories. The full Level 2 was recreated as part of the transition from Rev. 3 to Rev. 4 of the PRA model. The description in Section E.2.2.2.1 only discusses versions prior to the PRA MOR Rev. 4.1. Revision 3 of the model had abandoned the full Level 2 analysis and only calculated LERF.

2.c Section E.2.2.3 states that Containment Event Tree (CET) top events represent questions that are answered based on previous work for Salem Level 2, recent accident progression research, and similar analyses for other nuclear plants. It is apparent, however, from later discussion that fault tree modeling was also used as a basis (e.g. fault tree YCI-GCI1100 was used to address "Containment Isolation" top event). It is not clear what the basis for the branch probabilities was for top events RCS Depressurization and Containment Heat Removal. Clarify the basis for addressing the branch point probabilities for these top events.

PSEG Response:

For RCS Depressurization, an existing human event already existed as part of the HRA. This event (SRV-XHE-FO-DEPCD) was directly used as the operator action portion of the RCS Depressurization event. The other portion of the RCS Depressurization event involved successful function of the PORVs, which already existed in the Level 1 model. The RCS Depressurization top event consisted of a fault tree combination of the human action and the fault tree for PORV operation.

Containment heat removal at Salem can be accomplished through either the containment fan cooler units (CFCUs) or through containment spray (CS) and recirculation. The Level 2 PRA models the containment heat removal function via gate CHR-L2, which includes gates YF-GCU1100 for the CFCUs, YSI-G1SI100 for CS injection, and YSR-G1YR100 for CS recirculation. Note that for some scenarios, CS and/or CFCU may not be available due to power or service water failure, and these sequences were modeled accordingly.

2.d Section E.2.2.4 provides the rationale for and describes the process of identifying appropriate parameters to bin Plant Damage States (PDSs). However, the third paragraph of Section E.2.2.4.1 states that "This permits the somewhat artificial boundary between the Level 1 event trees and the containment event trees (i.e. the PDS) to be eliminated from this analysis". Clarify the meaning of "artificial" and "eliminated" and how PDSs are considered in the SAMA analysis.

PSEG Response:

In some analysis methods, the Level 1 endstates must be collected into endstates and the sum frequency of each endstate calculated, which is then passed to a separate Level 2 analysis along with the key characteristics of each plant damage state. This is what is referred to as the "artificial" boundary between Level 1 and Level 2. With the integrated one-top model used for the Salem Level 2 analysis, the Level 1 core damage cut sets are directly passed to the Level 2 model via incorporation of the Level 1 sequence fault trees. Therefore, the "artificial" boundary is "eliminated", in that the individual plant damage state frequencies need not be calculated. Plant damage states are still used within the Level 2 analysis to collect sequences with the identified characteristics and route them to the appropriate part of the Level 2 fault tree. For example, a fault tree gate (PDS-456-ABCD-AFW) collects all the Level 1 sequence fault trees (e.g., TCA2S03, TCA2S08, and many others) that belong to plant damage state 4A, 4B, 4C, 4D, 5A, 5B, 5C, 5D, 6A, 6B, 6C, or 6D and have AFW available. Level 1 sequences with these plant damage states contribute to the LERF02 Level 2 sequence, so the PDS gate is ANDed with the appropriate Level 2 top events to create the Level 2 sequence, which therefore directly incorporates the Level 1 sequences beneath this PDS gate.

2.e Identify the version of MAAP used in the SAMA analysis.

PSEG Response:

The MAAP code used for the Salem SAMA analysis was version 4.0.6.

2.f Section E.2.2.7.1 states that for the LATE release categories the "most likely initiators and sequences" were chosen to represent the category, while for the LERF release categories both the likelihood and the consequences were considered in selecting representative sequences. Justify why the consequences were not also considered in identifying the representative sequence for LATE releases since, as indicated in Table E.3-7, LATE-CHR-NOAFW accounts for more than 50 percent of the Dose-Risk and more than 30 percent of the offsite economic cost risk (OECR). In addition, clarify what is meant by "most likely initiators and sequences" and provide an example of how this is applied for release category LERF-CFE.

PSEG Response:

For each release category, an assessment of the most likely initiators and sequences was performed to aid in the selection of representative sequences. For the LATE release categories, the sequences within each specific category possessed similar enough consequences that the selection was based on the most likely sequences. Since the LATE scenarios take more time to evolve than the LERF scenarios, variations in the initial accident conditions do not produce as great an effect on the outcome, so consequences within a LATE release category are more uniform.

The most likely initiators and sequences were determined by examining the contributing initiating events and sequences to each category. The contribution by initiating event is easily seen by examining the FV importances of the initiating event basic events (or initiator flags). For example, for LERF-CFE, event %TVC (Loss of Control Area HVAC) contributes to 41% of the sequences, followed by %TSW (Loss of Service Water) at 19%. TVC was therefore chosen as the representative initiating event. LERF-CFE is made up of Level 2 sequences, LERF01, LERF02, LERF03, LERF04, & LERF05. The structure of the Level 2 model allows each of these Level 2 sequences to be quantified independently. LERF03 shows the highest frequency among the contributors, so its characteristics were chosen as the most likely Level 2 sequence for the LERF-CFE representative sequence. LERF03 models scenarios that remain at high pressure, fail AFW, have successful RCS depressurization by the operators through the PORVs, but experience early containment failure due to a hydrogen burn at the time of vessel failure. Thus, the LERF-CFE representative sequence is summarized as a TVC scenario without AFW, with containment failure at vessel breach.

2.g Page 3-4 reports that the licensed thermal power for SNGS Unit 1 is 3,459 MWt, which equates to a net electrical output of 1,195 MWe when operating at 100 percent power. Page E-59 states that the current licensed power is 3468 MWt, but that the core inventory is based on a thermal power level of 3632 MWt (5 percent above the licensed power level). Provide the rationale for using 3632 MWt in determining the core inventory used in the SAMA analysis.

PSEG Response:

The 3632 MWt power level is based on a Salem core inventory calculation (Reference PSEG 2005a in Appendix E of the Environmental Report). The 3632 MWt value is 5% above the licensed value of 3,459 MWt (3,459 MWt x 1.05 = 3632 MWt). The reference to a "current licensed value of 3468 MWt" on page E-59 is an error. The correct licensed power level value is 3,459 MWt as stated on page 3-4. The Salem core inventory calculation notes that a 5% margin above the current license level was applied to provide additional margin for a future power uprate. The 5% power level margin introduces a small conservatism in the MACCS2 results for 50-mile population dose and cost since population dose and cost are generally proportional to the core inventory, which is generally proportional to the core power level.

3. Provide the following information with regard to the treatment and inclusion of external events in the SAMA analysis:

3.a Section E.5.1.5.1.3 identifies that PSEG has replaced CO2 fire suppression systems with water sprinkler systems in several areas at Salem since the IPEEE. For each of the dominant fire areas, explain what additional measures, if any, have already been taken (since the IPEEE) to reduce fire risk. Include in the response specific improvements to fire detection systems, enhancements to fire suppression capabilities, changes that would improve cable separation, and improvements to processes/procedures for monitoring and controlling the quantity of combustible materials in critical areas.

PSEG Response:

The following table summarizes the additional measures that have been taken since the completion of the IPEEE to reduce fire risk in the nine dominant fire areas (PACR > $50,000):

FIRE AREA IDENTIFIER	FIRE AREA DESCRIPTION	ADDITIONAL RISK REDUCING MEASURES
1FA-AB-84A	460V Switchgear Rooms	None.
1FA-AB-100A	Relay Room	None.
12FA-AB-122A	Control Rooms, Peripheral Room, and Ventilation Rooms	None.
1FA-AB-64A: 4160	Switchgear Room	Revised the ventilation system and strategy for maintaining viable working conditions.
1FA-EP-78C	Lower Electrical Penetration Area	None.
1FA-EP- 100G/ 1F1-PP- 100H	Upper Electrical and Piping Penetration Areas	Revised the ventilation system and strategy for maintaining viable working conditions.
1FA-AB-84B	Reactor Plant Aux Equip Area	None.
12FA-SB- 100/ 1FA-TGA-88	Turbine and Service Buildings	This fire area contains the offsite power lines that provide power to the emergency 4kV buses. In order to reduce initiating event frequency of fires that would damage these cables, the maintenance shop that was located here was eliminated.
12FA-SW- 90A/90B	Service Water Intake	None.

In addition, two general plant changes have been made that can potentially reduce the fire risk in more than one of these fire areas:

- Added the capability to use an inter-unit positive displacement pump cross-tie for RCP seal cooling.
- Added the capability to use an inter-unit electrical cross-tie to support long term use of certain plant instrumentation (and facilitate the long term use of turbine driven AFW).

3.b Section E.5.1.5 presents a table that summarizes the status of three potential plant improvements based on the results of the IPEEE processes. The IPEEE SER identifies five additional potential plant improvements as follows: (1) a procedural change to ensure long term alternate ventilation for the Auxiliary Building, (2) the replacement of identified low ruggedness relays with higher seismic capacity relays, (3) a procedural change to enhance cooling in the switchgear and control areas in the event of a fire, (4) improved hold downs for the hydrogen tanks to protect against tornadoes, and (5) modifications to the plant circulating water intake structure to protect against detritus (blockage). (Section 5.1.6.4 seems to indicate that Item (4) has been implemented and Section E.5.1.6.7 seems to indicate that Item (5) has been implemented.) Confirm that all of these items have been implemented. If not, provide an evaluation of a SAMA that addresses those improvements that have not been implemented.

PSEG Response:

Salem LRA Section E.5.1.5 presents the three potential plant improvements that are described in Section 7 of the Salem IPEEE submitted on January 29, 1996. The Salem IPEEE SER dated May 21, 1999 identifies five additional potential plant improvements that do not appear in Section 7 of the Salem IPEEE. These five improvements appear to refer to information in other sections of the Salem IPEEE as well as to the Salem IPEEE cover letter. They do not appear in the Salem IPEEE supplement submitted on April 9, 1998. These five improvements are listed as Improvements 1 through 5 in the following table.

Based on the Salem IPEEE submittal on January 29, 1996, Improvements 1 and 3 may refer to the same improvement. On Page 1 of the cover letter, there is a commitment to make procedural changes to "ensure long term alternate ventilation for rooms in the Auxiliary Building". On the signature page for the commitment (Page 4), the text reads "implement new procedures for complete loss of HVAC for Switchgear Rooms and Control Area". This text apparently defines which rooms in the Auxiliary Building are covered by the procedural changes.

The Salem IPEEE SER states that all five of these improvements "have been implemented". However, one of the improvements, the design change to the Salem 2 hydrogen tank rack on the Auxiliary Building roof, was <u>not</u> implemented as stated in the Salem IPEEE SER or Salem LRA Section E.5.1.6.4 (Notification 20459932). In Section 5.3.3 of the Salem IPEEE, this improvement was characterized as "being changed" (i.e. implementation not complete).

Due to the incorrect characterization of the hydrogen tanks in Salem LRA Section E.5.1.6.4, the three potential plant improvements described in Salem LRA Section E.5.1.5 were re-verified with respect to implementation status. Implementation status was found to be correctly characterized. These three improvements are listed as Improvements a through c in the following table.

IMPROVEMENT #	DESCRIPTION	IMPLEMENTED (YES / NO)	JUSTIFICATION
1	Procedural change to ensure long term alternate ventilation for the Auxiliary Building.	Yes	**Source of Improvement: Salem IPEEE Section 3.1.5.3.2, Salem IPEEE Cover Letter (Page 1)** This improvement may refer to the same changes as Improvement 3. The following procedures contain guidance to ensure long term alternate ventilation for the Auxiliary Building. S1.OP-SO.ABV-0001(Q), Auxiliary Building Ventilation System Operation S2.OP-SO.ABV-0001(Q), Auxiliary Building Ventilation System Operation S1.OP-SO.PC-0001(Q), Switchgear and Penetration Areas Ventilation Operation S2.OP-SO.PC-0001(Q), Switchgear and Penetration Areas Ventilation Operation S1.OP-AB.CAV-0001(Q), Loss of Unit 1 Control Area HVAC S2.OP-AB.CAV-0001(Q), Loss of Unit 2 Control Area HVAC

IMPROVEMENT #	DESCRIPTION	IMPLEMENTED (YES / NO)	JUSTIFICATION
2	Replacement of identified low ruggedness relays (LRRs) with higher seismic capacity relays.	Yes	**Source of Improvement: Salem IPEEE Section 3.1.5.4** Salem IPEEE Section 3.1.5.4.1 states that "some of the identified LRRs had been replaced with higher seismic capacity relays". The 4kV Phase A/B/C diesel generator differential relays described in the Salem IPEEE SER belong to this category. Salem IPEEE Section 3.1.5.4.3 states that although there are several types of LRRs at Salem, "none of the relays would impact safe shutdown of the plant or containment performance after an earthquake". Based on this information, it is concluded that the LRRs "identified" for replacement with higher seismic capacity relays were replaced. The remaining LRRs do not impact safe shutdown.
3	Procedural change to enhance cooling in the switchgear and control areas in the event of a fire.	Yes	**Source of Improvement: Salem IPEEE Section 3.1.5.3.2, Salem IPEEE Cover Letter (Page 4)** This improvement may refer to the same changes as Improvement 1. The following procedures contain guidance to enhance cooling of the associated areas in the event of a fire. S1.OP-SO.PC-0001(Q), Switchgear and Penetration Areas Ventilation Operation S2.OP-SO.PC-0001(Q), Switchgear and Penetration Areas Ventilation Operation S1.OP-AB.CAV-0001(Q), Loss of Unit 1 Control Area HVAC S2.OP-AB.CAV-0001(Q), Loss of Unit 2 Control Area HVAC

IMPROVEMENT #	DESCRIPTION	IMPLEMENTED (YES / NO)	JUSTIFICATION
4	Improved hold downs for the hydrogen tanks to protect against tornados.	No	**Source of Improvement: Salem IPEEE Section 5.3.3, Salem LRA Section E.5.1.6.4** The hydrogen racks on the Auxiliary Building roof were walked down on 04/20/10. The Salem 2 configuration is not equivalent to the Salem 1 configuration. The design change described in Section 5.3.3 of the Salem IPEEE was not implemented. **Salem LRA Section E.5.1.6.4 is incorrect.** Section 5.3.3 of the Salem IPEEE describes the Salem 2 hydrogen tank rack as "being changed" (i.e. not implemented) so this discrepancy does not involve an error in the Salem IPEEE. Additionally, this section states that these hydrogen tanks "will not have any significant impact on safety structures" indicating that although the changes to the Salem 2 hydrogen rack was considered prudent, it did not have a significant impact on the IPEEE. With an averted cost-risk of $0, a SAMA is not required.

IMPROVEMENT #	DESCRIPTION	IMPLEMENTED (YES / NO)	JUSTIFICATION
5	Modifications to the plant circulating water intake structure to protect against detritus (blockage).	Yes	**Source of Improvement: Salem IPEEE Section 5.8, Salem LRA Section E.5.1.6.7** Section 5.8 of the Salem IPEEE contains a list of circulating water intake structure modifications. However, only short descriptions are available so the extent of these modifications is not perfectly clear. Therefore, the following questions were asked of the Circulating Water Intake System Manager. These questions probe each of the modification areas. The answers provide an alternate indication that there are no open issues in these areas and thus the modifications have been implemented. 1) Are there blowdown fittings on the screen wash headers? **Yes. (DCRMS Drawings 205209, 2459060)** 2) Are the screen wash pumps capable of digesting limited detritus? **Yes.** 3) Are there any significant materiel problems with the screen wash pump stilling tubes and base plates? **No.** 4) Are there any reliability problems with the screen wash pump motors and cables? **No.** 5) Are there any corroded portions of the screen wash piping significantly affecting screen wash operation? **No.** 6) Do the screen wash control panels allow for automatic screen wash operation? **Yes.**

IMPROVEMENT #	DESCRIPTION	IMPLEMENTED (YES / NO)	JUSTIFICATION
a	Reinforcement of an 8-foot masonry wall in the 4kV switchgear room.	No	**Source of Improvement: Salem IPEEE Section 7.1, Salem LRA Section E.5.1.5** This issue involves the potential vulnerability of nearby 4kV switchgear if the masonry wall was to collapse during a seismic event. Section 7.1 of the Salem IPEEE describes the result of the associated evaluation (CR 951020095, CREV 02). This evaluation states that "there is no interaction between the wall and the bus during a seismic event". The technical reference is EPRI NP-6041-SL, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin (Revision 1)". The only Corrective Action involved the revision of the associated calculation (6S1-1874) to clarify the lack of interaction. Based on this information, it is concluded that reinforcement of the masonry wall was not necessary and there were no modifications to implement.
b	Procedural change for the control of transient combustibles in the turbine building.	Yes	**Source of Improvement: Salem IPEEE Section 7.1, Salem IPEEE Cover Letter (Pages 1 and 4), Salem LRA Section E.5.1.5** FP-AA-011, Control of Transient Combustible Material, applies to "Critical Buildings" (Step 1.1). The Salem Turbine Buildings are defined as Critical Buildings (Attachment 4).

IMPROVEMENT #	DESCRIPTION	IMPLEMENTED (YES / NO)	JUSTIFICATION
c	Address water ingress pathways for external flooding events: 1) Penetrations 2) Inadvertent open door between Service Building and Auxiliary Building. 3) Leaking through seal between containment and the inner penetration area.	Yes	**Source of Improvement: Salem IPEEE Sections 5.4.2 & 7.1, Salem LRA Section E.5.1.5** This issue involves three potential water ingress pathways during external floods. 1) penetrations, 2) an inadvertently open door, and 3) leakage through the seal between the containment and the inner penetration area. Only one of the pathways, penetrations, was determined to be significant. A penetration improvement program was implemented to ensure that the affected penetrations were properly sealed at both Salem 1 and 2. As described in Section 7.1 of the Salem IPEEE, "the completion of this design change program has ensured that penetrations of potential significance are properly sealed, and has eliminated external floods as a potentially significant contributor to CDF for both units". Based on this information, all actions to address the three potential water ingress pathways have been completed.

3.c Section E.4.6.2 mentions the interim SNGS fire model (SCIENTECH 2003) that was used to provide insights for three fire areas in which fire suppression systems were changed since the IPEEE. Provide the background/history of the development of this model and a brief description of the model. Clarify in the response whether the model is an evolution of the IPEEE model or a completely new model, whether the model was integrated with the Level 1 model or is a stand-alone model, to what PRA standards the model was developed, and why the model has not been implemented at Salem.

PSEG Response:

After completion of the IPEEE, an effort was made to replace it with a fire PRA, which resulted in the development of the SGS fire modeling methodology and a partially complete "interim SGS fire model". The interim SGS fire model was not an update of the IPEEE, but a completely new and separate model. While it was not integrated with Revision 3.0 of the SGS internal events PRA model in a manner that would produce combined results, it used the internal events PRA model logic for quantification.

During the development of the interim model, it was determined that the forthcoming NUREG/CR-6850 guidance would render the SGS fire modeling methodology obsolete. Because of PSEG's intent to maintain consistency with the industry and because of difficulties encountered using the SGS fire modeling methodology, the interim model was abandoned and it was never officially released or peer reviewed. Given the incomplete state of the model, no official insights from the model were released.

3.d A liquefied natural gas terminal has been approved for construction in Logan Township, NJ. Discuss the status of this facility and the potential impact of the transportation of LNG to this facility on SNGS during the license renewal period.

PSEG Response:

On June 20, 2006, the Federal Energy Regulatory Commission (FERC) issued its *Order Granting Authority Under Section 3 of the Natural Gas Act and Issuing Certificate,* which authorized Crown Landing LLC to construct and operate a liquefied natural gas (LNG) terminal in Logan Township, NJ once it satisfies a number of conditions, including acquisition of all required state environmental permits and approvals [*Crown Landing LLC,* 115 FERC 61,348 (2006)]. Ordering Paragraph D of the Order requires Crown Landing to complete construction of, and make available for service, the authorized facilities within three years of the date of the Order – by June 20, 2009. In a letter dated April 17, 2009, the FERC extended the deadline for completing construction and putting the LNG terminal into service until June 20, 2010. In a letter dated March 15, 2010, BP, the owner of Crown Landing LLC, notified the FERC that 100 percent ownership of Crown Landing LLC was transferred to Hess LNG Crown Landing LLC, a Hess LNG affiliate, effective October 28, 2009.

PSEG Nuclear has determined that construction of the Crown Landing LNG terminal had not yet commenced as of March 31, 2010. Furthermore, the Delaware Department of Natural Resources and Environmental Control has denied applications for several required environmental permits and approvals. Hence, although the Crown Landing LNG terminal may ultimately be constructed and placed into service, details concerning LNG deliveries to the terminal are uncertain at this time. Accordingly, any assessment of specific severe accident impacts on Salem during the license renewal period from transportation of LNG to the Crown Landing LNG terminal would be purely speculative. Even so, considering the regulatory process and controls for assuring safety and security that apply to LNG marine traffic and tankers and the safety record of LNG ships, all of which are summarized in the following paragraphs, PSEG believes analysis for Salem of severe accident mitigation alternatives associated with a possible future LNG terminal in Logan Township, NJ, is not currently warranted.

<u>Regulation of LNG Marine Traffic</u>

While the FERC is the federal agency responsible for authorizing construction and operation of onshore LNG facilities, the U.S. Coast Guard (Coast Guard) is the federal agency responsible for issuing Letters of Recommendation (LORs) pursuant to 33 CFR 127.009 regarding the suitability for LNG marine traffic of the waterways on which such facilities will be located. The Coast Guard is also responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks.

The Coast Guard bases its LOR for a waterway on the following:

- Information in a letter of intent submitted by the owner or operator of the proposed LNG facility, which must provide:
  - The physical location of the facility;
  - A description of the facility;
  - The LNG vessels' characteristics and the frequency of LNG shipments to or from the facility; and
  - Charts showing waterway channels and identifying commercial, industrial, environmentally sensitive, and residential areas in and adjacent to the waterway used by the LNG vessels en route to the facility, within 25 kilometers (15.5 miles) of the facility.
- Density and character of marine traffic in the waterway;
- Locks, bridges, or other manmade obstructions in the waterway; and
- The nature of the following factors adjacent to the facility:
  - Depths of the water.
  - Tidal range.
  - Protection from high seas.
  - Natural hazards, including reefs, rocks, and sandbars.
  - Underwater pipelines and cables.
  - Distance of berthed vessel from the channel and the width of the channel.

The process of preparing the LOR begins when an applicant submits a Letter of Intent (LOI) to the appropriate COTP in accordance with 33 CFR 127.007. If the Coast Guard were to issue a LOR that found the Delaware Bay/River waterway suitable for LNG marine traffic, the arrival, transit, cargo transfer, and departure of LNG ships in the Delaware River would be required to adhere to the procedures of a *LNG Vessel Transit Management Plan,* which would be developed by the Coast Guard Sector Delaware Bay. In addition, the LNG terminal itself would develop Operations and Emergency Manuals in consultation with the Coast Guard. These procedures would be developed to ensure the safety and security of all operations associated with LNG ship transit and unloading. The *LNG Vessel Transit Management Plan* would contain specific requirements for LNG ships, pre-arrival notification, transit through the Delaware Bay and River, the waterfront facility, cargo transfer operations, Coast Guard inspection and monitoring activities, and emergency operations. The Coast Guard Sector Delaware Bay would monitor each LNG ship in accordance with the *LNG Vessel Transit Management Plan.* Some of the anticipated key provisions of an *LNG Vessel Transit Management Plan* are establishment of a moving safety and/or security zone for all inbound and moored LNG ships, use of tugs to assist in the Delaware River and to maneuver the ship into the berth, and requirement that tug(s) remain with the LNG ship while it is moored at the berth.

If the Coast Guard issues a LOR finding the waterway suitable for LNG marine traffic the Coast Guard would promulgate a moving safety zone which would affect other vessels. Pursuant to such a regulation, no vessel would be allowed to enter the safety zone without first obtaining permission from the Coast Guard

Captain of the Port. The Captain of the Port currently places similar restrictions on all vessels transiting the Delaware River and Bay carrying certain dangerous cargoes (CDC) by regulation in 33 CFR 165.510. Presently, the moving safety zone around LNG ships is 1,000 yards ahead and behind, and 500 yards on either side of the vessel. Minimum visibility conditions would have to be satisfied before the LNG ship would be allowed to proceed inbound from the ocean, ensuring that the Coast Guard could adequately monitor the safety zone. Currently there is a 100 yard security zone for moored or anchored vessels carrying dangerous cargo. The regulation provides the Coast Guard and local law enforcement personnel with the authority to implement additional control measures within the zone, such as check points, should such action be warranted based on a specific threat or credible intelligence. Additionally, it is important to note that the requirements of 33 CFR 165.150 were designed to apply to any CDC vessel transiting the Delaware Bay and River, and does give consideration to security measures that may be applied to mitigate risk.

Regulation of Ship Design and Construction

Besides complying with the Coast Guard's controls on LNG marine traffic, LNG ships used to import LNG to the United States would be constructed and operated in accordance with the International Maritime Organization (IMO) Code for the Construction and Equipments of Ships Carrying Liquefied Gases in Bulk, the International Convention for the Safety of Life at Sea (SOLAS), and 46 CFR Part 154, which contain the U.S. safety standards for vessels carrying bulk liquefied natural gas. Foreign flag LNG ships are required to possess a valid IMO Certificate of Fitness and a Coast Guard Certificate of Compliance. In 1993, amendments to the IMO's Code for the Construction and Equipments of Ships Carrying Dangerous Chemicals in Bulk required all tankers to have monitoring equipment with an alarm facility which is activated by detection of over-pressure or under-pressure conditions within a cargo tank. In addition, the cargo tanks are heavily instrumented, with gas detection equipment in the hold and inter-barrier spaces, temperature sensors, and pressure gauges. Fire protection must include the following systems:

- A water spray (deluge) system that covers the accommodation house control room and all main cargo valves;
- A traditional firewater system that provides water to fire monitors on deck and to fire stations found throughout the ship;
- A dry chemical fire extinguishing system for hydrocarbon fires; and
- A carbon dioxide system for protecting machinery, including the ballast pump room, emergency generators, and compressors.

As a result of the terrorist acts that occurred on September 11, 2001, the IMO agreed to new amendments to the 1974 SOLAS addressing port facility and ship security. As a result, the International Ship and Port Facility Security Code was adopted in 2003 by the IMO. This code requires both ships and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against ships, improve security aboard ships and ashore, and reduce the risk to passengers, crew, and port personnel on board ships and in port areas, for vessels and cargoes. All LNG ships, as well as other cargo vessels 300 gross tons and larger and ports servicing those regulated vessels, must adhere to these IMO and SOLAS standards. Some of the IMO requirements are as follows:

- Ships must develop security plans and have a Ship Security Officer;
- Ships must be provided with a ship security alert system. These alarms transmit ship-to-shore security alerts to a competent authority designated by the Administration, which may include the company, identifying the ship, its location and indicating that the security of the ship is under threat or it has been compromised;
- Ships must have a comprehensive security plan for international port facilities, focusing on areas having direct contact with ships; and
- Ships may have certain equipment onboard to help maintain or enhance the physical security of the ship.

LNG Ship Safety

Since 1959, LNG has been transported by ship without a major release of cargo or a major accident involving an LNG ship. Starting in 1971, LNG began arriving at the Distrigas facility in Everett, Massachusetts. As of early 2006, more than 680 cargoes, with volumes ranging from 60,000 to 125,000 m^3, have been delivered into the Port of Boston without incident. During 2005, an estimated total of 631 billion cubic feet (241 cargoes) of LNG was imported into the United States. For 35 years, LNG shipping operations have been safely conducted in the United States. [Federal Energy Regulatory Commission, 2006. *Final Environmental Impact Statement,* Crown Landing LNG and Logan Lateral Projects. Docket Nos. CP04-411-000 and CP04-416-000. FERC/EIS – 0179. April.]

The world's LNG ship fleet currently exceeds 173 carriers. Over the last 45 years, LNG ships have made over 44,000 voyages. Currently, all of the ships in the LNG fleet operate under a foreign flag with foreign crews. A foreign flag ship must have a Certificate of Compliance inspection by the Coast Guard to ensure compliance with international safety standards. [Federal Energy Regulatory Commission, 2006. *Final Environmental Impact Statement,* Crown Landing LNG and Logan Lateral Projects. Docket Nos. CP04-411-000 and CP04-416-000. FERC/EIS – 0179. April.]

Conclusion

Based on (1) the regulatory process and controls for assuring the safety and security of LNG ships, (2) the safety record of LNG ships, and (3) the uncertainty of the Crown Landing LNG terminal project, PSEG submits that analysis for Salem of severe accident mitigation alternatives associated with a possible future LNG terminal in Logan Township, NJ, is not currently warranted.

4. Provide the following information concerning the MACCS2 analyses:

4.a Section E.3.2 states that SECPOP2000 census data from 1990 to 2000 were used to determine the population growth factor, and that the population growth was averaged over each ring and applied uniformly to all sectors within each ring. Using an average growth over a ring mixes growth rates from significantly different regions. For example; portions of Kent County, Delaware, Chester County, Pennsylvania, and Cumberland County New Jersey will lie on similar rings. Between years 2000 and 2003, they had population growths of 6.1%, 5.5% and 2.0%, respectively (http://www.epodunk.com/top10/countyPop/coPop8.html, http://www.epodunk.com/top10/countyPop/coPop39.html, and http://www.epodunk.com/top10/countyPop/coPop31.html). Provide an assessment of the potential impact on PDR and OECR if a wind-direction weighted growth estimate for each sector were used.

PSEG Response:

Population projection necessitates a range of approximations. In general, population growth rates are found to differ substantially based on radial distance from the site and it is desirous to include these radial variations. Angular variations in growth rates are generally viewed as being of secondary importance due to lateral plume dispersion as a function of distance and the use of mean values in the SAMA analysis; however, it can be envisioned that angular population growth rate variations could become important if combined with strong wind direction variations.

Significant radial growth rate differences for the 1990 to 2000 period are evident in the Salem radial growth rates for each ring around the site, varying from 38% per ten years for the 4-to-5 mile ring to 1% per ten years at the 30-to-40 mile ring. "Whole County" based population growth rates do not address population growth rate differences within a county and often do not capture the radial variation in relationship to the site (dependent upon the size and orientation of the county relative to the site). For example, Cumberland County, NJ, situated due east of the site begins approximately 7 miles from the site and extends to approximately 35 miles from the site. Growth rate variations used in the SAMA analysis varied between 17% (5-to-10 mile ring) and 1% (30-to-40 mile ring) for this county. Use of a single county growth rate value for Cumberland County would not capture this radial variation. Similarly, for Kent County, DE, located approximately due south of the site (extending from an approximate radial distance of 8 miles to 45 miles) the SAMA analysis growth rates varied from 1% to 17%. For Chester County, PA, (which extends approximately 23 miles from the site to outside the 50-mile region), the SAMA analysis growth rates varied from 1% to 9% dependent upon the distance from the site.

As part of the MACCS2 processing of meteorological data, wind direction is tabulated and binned for the 8760 hours of annual data according to 16 directional sectors. For the Salem SAMA base case year of meteorology (2004), the wind direction frequency is found to be relatively even for the 16 sectors, as shown in the following table:

WIND BIN (SECTOR)	WIND DIRECTION (BLOWING TOWARDS)	FREQUENCY (/YR)	DOWNWIND COUNTIES
1	N	0.056	NJ – Salem, Gloucester PA – Delaware, Chester, Philadelphia, Montgomery DE – New Castle
2	NNE	0.059	NJ – Salem, Gloucester, Camden, Burlington PA – Philadelphia, Montgomery
3	NE	0.062	NJ – Salem, Cumberland, Gloucester, Camden, Atlantic, Burlington
4	ENE	0.057	NJ – Salem, Cumberland, Gloucester, Atlantic, Burlington
5	E	0.058	NJ – Salem, Cumberland, Atlantic, Cape May
6	ESE	0.067	NJ – Salem, Cumberland, Cape May
7	SE	0.101	Primarily Delaware Bay NJ – Salem, Cape May DE – Kent, Sussex
8	SSE	0.069	NJ – Salem DE – New Castle, Kent, Sussex
9	S	0.066	NJ – Salem DE – New Castle, Kent, Sussex MD – Caroline, Talbot
10	SSW	0.069	NJ – Salem DE – New Castle, Kent MD – Kent, Queen Anne's, Caroline, Talbot
11	SW	0.067	NJ – Salem DE – New Castle MD – Kent, Cecil, Queen Anne's, Baltimore
12	WSW	0.046	NJ – Salem DE – New Castle MD – Kent, Cecil, Hartford, Baltimore
13	W	0.027	NJ – Salem DE – New Castle MD – Cecil, Hartford PA – York, Lancaster

WIND BIN (SECTOR)	WIND DIRECTION (BLOWING TOWARDS)	FREQUENCY (/YR)	DOWNWIND COUNTIES
14	WNW	0.028	NJ – Salem DE – New Castle MD – Cecil PA – Chester, Lancaster, York
15	NW	0.099	NJ – Salem DE – New Castle PA – Chester, Lancaster
16	NNW	0.067	NJ – Salem DE – New Castle PA – Chester, Delaware, Montgomery
Total	--	1.00	--
Average	--	0.063	--

Per the table above, the highest wind frequency (0.101, Southeast) is primarily associated with the Delaware Bay. This sector has negligible population. The second highest wind frequency (0.099) is in the opposite direction (i.e., Northwest) and includes a significant portion of Chester County, PA. One of the lowest frequencies (i.e., 0.028, WNW) is adjacent and contains portions of southern Chester County. The other adjacent sector (NNW) also contains significant portions of Chester County and has a frequency (0.067) close to the average (0.063). It is noted that for Chester County, which is situated more than 20 miles from the site, a postulated release is expected to have dispersed laterally across several sectors by the time such a radial distance is achieved. If the frequencies of the three primary sectors for Chester County (i.e., WNW, NW, and NNW) are averaged, a frequency of 0.065 is determined ((0.028+0.099+0.067)/3=0.0647), which is very close to the average sector value of 0.063.

Based on the relatively even wind direction profile surrounding the site, the propensity for lateral release dispersion into adjacent sectors as a function of radial distance, and the use of mean values in the SAMA analysis, it was judged that the impacts associated with angular growth rates on PDR and OECR are minimal and bounded by the 30% population increase sensitivity case that was performed as part of the SAMA analysis.

4.b Section E.3.2 does not discuss transient population. Clarify whether transient population was considered in the analysis. If a transient population was not considered, provide a justification/rationale for not including it.

PSEG Response:

Transient population was included for the 10-mile region around the site based on data in the site evacuation time estimate study (Reference KLD 2004 in Appendix E of the Environmental Report). Transient population data was included prior to population projection. This is consistent with the guidance in NEI 05-01. Transient data are most applicable to evacuation-related modeling.

4.c Section E.7.3.4 describes a population sensitivity case in which the 2040 population was uniformly increased by 30 percent in all sectors of the 5-mile radius. Section E.3.2 states that SECPOP2000 census data from 1990 to 2000 were used to determine the 10 year population growth factor. It is unclear if the 30 percent sensitivity case bounds the population growth rate if updated population growth estimates are used (see RAI 4a). Provide an assessment of the impact on PDR and OECR using currently available population growth estimates for the surrounding counties and states.

PSEG Response:

As indicated in the response to RAI 4.a, the use of "whole county" growth estimates is not generally preferred since the resolution of such data is less than that available using the data contained in the SECPOP2000 census data. Particularly, radial variations in growth rates may be significantly under represented using "whole county" data. Additionally, it was noted that the 10-year growth rates used in the SAMA analysis varied significantly, including growth rate factors as high as 1.38 (e.g., 4-5 mile ring).

It was also noted that the 30% population sensitivity performed for the 50-mile SAMA analysis was performed by increasing the 2040 population of each polar grid cell by 30% rather than by increasing the population growth factor by 30%. This is approximately equivalent to adding 6.8% to the 10-year growth percentage of each ring. For example, for the 30% sensitivity case, the equivalent 10-year growth for the 40-50 mile ring would be increased from 4% to 10.8%. Thus, the 30% sensitivity case is approximately equivalent to assuming the following 10-year growth percentages:

RADIAL RING (MILES)	BASE CASE 10-YEAR GROWTH (%)	30% SENSITIVITY 10-YEAR EQUIVALENT GROWTH (%)
0-1	0	6.8
1-2	0	6.8
2-3	0	6.8
3-4	19	25.8
4-5	38	44.8
5-10	17	23.8
10-20	16	22.8
20-30	9	15.8
30-40	1	7.8
40-50	4	10.8

The table above was judged to represent a significant population growth adjustment that adequately bounds anticipated sustained growth through 2040. For the purposes of SAMA, the data utilized in the Salem MACCS2 analysis, in combination with the 30% population sensitivity case, was judged to adequately support growth projections.

4.d Section 3.1.2 identifies the allowable fuel burnup and enrichment for SNGS. Confirm that this is consistent with the core inventory used in the SAMA analysis.

PSEG Response:

The allowable fuel burnup and enrichment identified in Section 3.1.2 are consistent with the core inventory used in the MACCS2 SAMA analysis. Salem 1 and 2 were issued License Amendments in February 2006 supporting full-scope implementation of Alternate Source Term (AST) as described in Regulatory Guide 1.183 (Amendments 271 and 252, respectively). The core inventory used in the AST submittals continues to reflect the current design and licensing bases, including the allowable fuel burnup and enrichment identified in Section 3.1.2. The SAMA MACCS2 analysis was based on the core inventory used in the AST submittals.

5. Provide the following with regard to the SAMA identification and screening process:

5.a It appears that the SAMA identification process eliminated many potential SAMAs by using the generic list of SAMAs in NEI 05-01 only to identify types of changes to address items identified through the importance list review (rather than starting with the generic list and eliminating SAMAs using the screening criteria). Justify that the Phase I SAMA identification and screening process produced a comprehensive sufficiently complete set of SAMAs for consideration, given that 17 of the 27 Phase 1 SAMAs were ultimately determined to be potentially cost-beneficial.

PSEG Response:

One of the reasons that the NEI 05-01 guidance was developed was to move the industry toward a SAMA identification process that was based on plant specific risks. The development of the guidance was initiated after the NRC review of the H.B. Robinson SAMA analysis. During this review, the NRC explicitly stated that a review of a generic SAMA list was of limited benefit; the generic SAMAs had been analyzed by multiple plants and were consistently found not to be cost beneficial. The real benefit was considered to be in the development of SAMAs generated from plant specific risk insights. The SGS SAMA identification process is consistent with this philosophy given that it is based on plant specific risk insights from the PRA models.

In addition, the generic SAMA list provided in NEI 05-01 has no intrinsic value. The list was derived from the body of SAMAs identified from previous SAMA submittals and other industry guidance (with duplicates deleted). There is no guarantee that the list of SAMAs is in any way comprehensive or that it is even relevant to any given plant beyond the fact that it includes potential plant enhancements that may have been derived from similar plants.

If the generic NEI 05-01 SAMA list were to be explicitly evaluated in a useful manner, each of the proposed SAMAs would have to be reviewed and then modified/extrapolated to match the systems or functions of the plant under consideration; otherwise, a large majority of the SAMAs would be screened as not being relevant to the plant. Even after modifying the SAMA so that it is relevant to the plant's systems/functions, further changes would be required to ensure that the SAMA would address the spectrum of risk relevant to the plant rather than just a portion of the risk. For example, SAMA 014 from Table 14 of NEI 05-01 is a SAMA to "Install a Gas Turbine Generator", which is already installed at SGS. If effort is not expended to consider the SAMA in the context of the plant, it would be screened as "already implemented". In order to make a SAMA related to the gas turbine meaningful to SGS, it would have to be modified such that it suggests simplifying the alignment of the existing gas turbine to the emergency buses. In addition, provisions for adding a dedicated line and transformer would address other significant risk factors related to weather related events (otherwise improvements to the alignment capability alone would have a limited impact). Obviously, SAMA 014 from Table 14 of NEI 05-01 would serve only as an idea source in a process to develop a SAMA that is relevant to the SGS design and risk factors.

As stated in Section E.5.1 of the ER, Table 14 of NEI 05-01 was used as an idea source to generate SAMAs for the important contributors to SGS risk. The process for developing the SAMA is essentially the same as described above, but the SAMAs to be reviewed are dictated by the PRA rather than using resources to disposition the entire contents of Table 14.

While it is true that many of the SGS SAMAs were found to be cost effective, it does not in any way imply that the original SAMA list is not comprehensive. The importance list/cutset review provides reasonable assurance that the meaningful risk contributors are addressed for the plant.

5.b Section E.5.1.1 explains that PSEG used a review threshold RRW of 1.01 for the Level 1 and 2 importance list reviews, which corresponds to a single unit averted cost-risk of about $164,000. This section also explains that the assumed cost of procedural changes in the SAMA analysis was $50,000 to $100,000 for the site and that the offsite economic cost-risk reduction corresponding to $50,000 would be 1.003. The section also acknowledges that performing a risk reduction worth (RRW) review to the level of 1.003 would likely generate additional unique SAMAs, some of which could be cost beneficial. Provide a review of basic events down to an RRW of 1.003 and an evaluation of any new SAMAs that arise from this review.

PSEG Response:

Section 5.1 of NEI 05-01 includes guidance on how to establish a reasonable and technically sound limit on the depth of the PRA results review for the SAMA identification task. The intent of the guidance is to ensure that the dominant risk contributors are included in the analysis, which is consistent with PSEG's method of using the definition of "risk significant" to set the lower limit of the importance list review. In terms of Risk Reduction Worth (RRW), which is the figure of merit for the SAMA identification process, the PSA Applications Guide (EPRI 1995) defines events with RRW values of 1.01 or greater to be risk significant. Review of the importance list below the 1.01 threshold is not considered to be required to meet the intent of NEI 05-01; however, information is available that is considered to further justify the completeness of the SGS SAMA list.

As a result of the SAMA analysis and other factors, PSEG has taken the initiative to implement SAMA 5A from the SGS ER submittal (Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries), to update the PRA to reflect this change (as well as those identified in the response to RAI question 1d), and to revisit the SAMA identification and quantification process using the updated PRA model. Table 5b-1 summarizes the PRA results for the updated model, which is designated as model-of-record (MOR) Rev. 4.3.

The updated importance list review was again performed for all events with RRW values greater than 1.006, which correlates to an averted cost-risk of $47,430.

As demonstrated in Tables 5b-2a and 5b-2b, most of the important contributors to the MOR Rev. 4.3 model are the same as those identified for the MOR Rev. 4.1 model used in the SAMA analysis. Some events that were not previously evaluated, such as "DGS-DGN-FR-SBO", can be addressed by existing SAMAs; however, a small number of events were considered to require new SAMAs to adequately address the areas of risk represented by those events. As a result, the MOR Rev. 4.3 importance list review yielded three new SAMAs:

- SAMA 30: Automatic Start of Diesel-Powered Air Compressor
- SAMA 31: Fully Automate Swapover to Sump Recirculation

- SAMA 32: Enhance Flood Detection for 100-foot Aux Building and Enhance Procedural Guidance for Responding to Internal Floods

In order to disposition these SAMAs, their net values were calculated based on rough cost estimates and Phase 2 PRA quantifications. As documented below, none of the three new SAMAs were found to be cost beneficial, even when the 95th percentile PRA results were applied.

SAMA 30: Automatic Start of Diesel-Powered Air Compressor

The operator action to start the diesel-powered air compressor is now more risk-significant in the newer Rev. 4.3 PRA model and can be mitigated by designing automatic controls that start and load the diesel air compressor when instrument air header pressure drops to an unacceptably low level.

PRA Model Changes to Model SAMA:

To simulate implementation of this SAMA, the failure probability for this operator action, which was identified as CAS-XHE-FO-CAE63 in the PRA model, was reduced by a factor of 100, i.e., the failure probability was changed from 6.30E-2 to 6.30E-4.

Results of SAMA Quantification:

Implementation of this SAMA yielded relatively small reductions in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	DOSE-RISK	OECR
Base Value	2.20E-05	20.16	$75,179
SAMA Value	2.18E-05	20.10	$74,927
Percent Change	1.0%	0.3%	0.3%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$Frequency_{BASE}$	9.06E-06	1.81E-10	9.64E-07	3.83E-08	1.08E-05	2.97E-08	9.79E-08	1.35E-08	1.11E-07	1.87E-07	7.46E-07	**2.20E-05**
$Frequency_{SAMA}$	8.88E-06	1.81E-10	9.64E-07	3.82E-08	1.07E-05	2.97E-08	9.71E-08	1.34E-08	1.11E-07	1.87E-07	7.41E-07	**2.18E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.10	13.45	0.62	1.02	0.15	1.01	0.74	2.92	**20.16**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.10	13.42	0.62	1.01	0.15	1.01	0.74	2.90	**20.10**
$OECR_{BASE}$	$29	$0	$5	$444	$35,938	$2,393	$3,885	$492	$5,000	$6,027	$20,966	**$75,179**
$OECR_{SAMA}$	$28	$0	$5	$443	$35,852	$2,393	$3,854	$488	$5,000	$6,027	$20,835	**$74,927**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 30 NET VALUE			
Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$7,956,000	$7,916,132	$39,868

The SAMA 30 results indicate a fairly small reduction in CDF, dose-risk and offsite economic consequences. Even if an implementation cost was optimistically chosen to be on the order of $100,000, the net value for this SAMA would be -$60,132 ($39,868 - $100,000), which implies that this SAMA is not cost beneficial.

At the 95th percentile case (which is a factor of 2.08 greater than the base case for MOR Rev. 4.3), the averted cost was estimated to be $82,925, which is still less than the assumed inexpensive implementation cost of only $100,000. For SAMA 30, it is most likely that the actual implementation cost would be much higher.

SAMA 31: Fully Automate Swapover to Sump Recirculation

The operator action to swap to sump recirculation, such as during LOCA scenarios, is now more risk-significant in the Rev. 4.3 PRA model and can be mitigated by designing automatic controls that perform the swapover process with little or no operator action required for success.

<u>PRA Model Changes to Model SAMA:</u>

To simulate implementation of this SAMA, the failure probability for this operator action, which was identified as RHS-XHE-FO-RECR1 in the PRA model, was reduced by a factor of 100, i.e., the failure probability was changed from 5.30E-3 to 5.30E-5.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded relatively small reductions in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	DOSE-RISK	OECR
Base Value	2.20E-05	20.16	$75,179
SAMA Value	2.18E-05	20.14	$75,121
Percent Change	1.1%	0.1%	0.1%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
Frequency_{BASE}	9.06E-06	1.81E-10	9.64E-07	3.83E-08	1.08E-05	2.97E-08	9.79E-08	1.35E-08	1.11E-07	1.87E-07	7.46E-07	**2.20E-05**
Frequency_{SAMA}	8.83E-06	1.81E-10	9.64E-07	3.83E-08	1.08E-05	2.97E-08	9.66E-08	1.32E-08	1.11E-07	1.87E-07	7.46E-07	**2.18E-05**
Dose-Risk_{BASE}	0.15	0.00	0.02	0.10	13.45	0.62	1.02	0.15	1.01	0.74	2.92	**20.16**
Dose-Risk_{SAMA}	0.14	0.00	0.02	0.10	13.45	0.62	1.00	0.14	1.01	0.74	2.92	**20.14**
OECR_{BASE}	$29	$0	$5	$444	$35,938	$2,393	$3,885	$492	$5,000	$6,027	$20,966	**$75,179**
OECR_{SAMA}	$28	$0	$5	$444	$35,938	$2,393	$3,836	$483	$5,000	$6,027	$20,966	**$75,121**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 31 NET VALUE			
Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$7,956,000	$7,928,939	$27,061

The SAMA 31 results indicate a fairly small reduction in CDF, dose-risk and offsite economic consequences. Even if an implementation cost was optimistically chosen to be on the order of $100,000, the net value for this SAMA would be -$72,939 ($27,061 - $100,000), which implies that this SAMA is not cost beneficial. At the 95th percentile, the averted cost was estimated to be $56,287, which is still less than the assumed inexpensive implementation cost of only $100,000. For SAMA 31, the actual implementation cost would be much higher.

SAMA 32: Enhance Flood Detection for 100-foot Aux Building and Enhance Procedural Guidance for Responding to Internal Floods

Internal flood events that occur on the 100-foot el. of the Auxiliary Building can disable electrical equipment in the relay room and adjoining DC battery rooms. The flood sources for this area of the Auxiliary Building involve the demineralized water and chemical volume and control systems. A flood of this nature could be readily detected and isolated. If steps were taken to make it easier to identify and resolve floods on this elevation of the Auxiliary Building, this would reduce the risk associated with these flooding events.

This SAMA proposes development of detection and procedural mitigation steps for floods on the 100-foot el. of the auxiliary building. The details are provided below.

PRA Model Changes to Model SAMA:

To simulate implementation of this SAMA, the failure probability for this operator action, which was identified as FL_XHE_AB100_G in the PRA model, was reduced by a factor of 100, i.e., the failure probability was changed from 1E-1 to 1E-3.

Results of SAMA Quantification:

Implementation of this SAMA yielded relatively small reductions in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	DOSE-RISK	OECR
Base Value	2.20E-05	20.16	$75,179
SAMA Value	2.18E-05	20.06	$74,786
Percent Change	1.0%	0.5%	0.5%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$Frequency_{BASE}$	9.06E-06	1.81E-10	9.64E-07	3.83E-08	1.08E-05	2.97E-08	9.79E-08	1.35E-08	1.11E-07	1.87E-07	7.46E-07	**2.20E-05**
$Frequency_{SAMA}$	8.89E-06	1.81E-10	9.64E-07	3.83E-08	1.07E-05	2.97E-08	9.42E-08	1.33E-08	1.11E-07	1.87E-07	7.41E-07	**2.18E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.10	13.45	0.62	1.02	0.15	1.01	0.74	2.92	**20.16**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.10	13.42	0.62	0.98	0.14	1.01	0.74	2.90	**20.06**
$OECR_{BASE}$	$29	$0	$5	$444	$35,938	$2,393	$3,885	$492	$5,000	$6,027	$20,966	**$75,179**
$OECR_{SAMA}$	$28	$0	$5	$444	$35,845	$2,393	$3,740	$485	$5,000	$6,027	$20,818	**$74,786**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 32 NET VALUE			
Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$7,956,000	$7,905,728	$50,272

The SAMA 32 results indicate a fairly small reduction in CDF, dose-risk and offsite economic consequences. Assuming that the per unit implementation cost is very similar to that proposed for SAMA 6, which was a value of $250,000, the net value for this SAMA would be -$199,728 ($50,272 - $250,000), which implies that this SAMA is not cost beneficial. At the 95th percentile, the averted cost was estimated to be $104,566, which is still less than the implementation cost of $250,000.

TABLE 5B-1
MOR REV. 4.3 MODEL RESULTS SUMMARY

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$Frequency_{BASE}$	9.06E-06	1.81E-10	9.64E-07	3.83E-08	1.08E-05	2.97E-08	9.79E-08	1.35E-08	1.11E-07	1.87E-07	7.46E-07	2.20E-05
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.10	13.45	0.62	1.02	0.15	1.01	0.74	2.92	20.16
$OECR_{BASE}$	$29	$0	$5	$444	$35,938	$2,393	$3,885	$492	$5,000	$6,027	$20,966	$75,179

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
RCS-SLOCA-SPLIT	1.207	1.091	SPLIT FRACTION FOR SEAL LOCA AFTER LOSS COOLING	Y	6	Associated with cutsets related to AB084C internal flood scenarios.
RRS-XHE-FO-SDRSP	1.192	1.940	FAILURE OF THE OPER TO SHUTDOWN FROM REMOTE SDP	Y	1	Associated with cutsets related to MCR ventilation.
AFS-XHE-FO-H2OLT	1.169	1.073	Failure to provide alternate suction source for AFW	Y	7	
%FL_AB084C_G_SW	1.135	1.060	General Flood Aux Bldg 84C Service Water	Y	6	
FL_XHE_AB084C_G	1.123	1.055	Operator fails to isolate flood source	Y	6	
AFS-XHE-FO-REFIL	1.118	1.050	FAILURE TO REFILL AFWST via DR6	Y	7	
AFS-MDP-FS-DF04	1.117	1.051	DEPEN FAILURE OF 3 AFW PUMPS (STEAM BINDING)	Y	8	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
%TVC	1.111	1.554	INITIATOR FLAG FOR LOSS OF CONTROL AREA HVAC IE-TVC	Y	1	
SRV-XHE-FO-FANDB	1.101	1.038	OPERATOR FAILS TO INITIATE FEED AND BLEED	Y	8	
%TT	1.101	1.041	TRANSIENT WITH PCS AVAILABLE INITIATOR	Y	7	
%TP	1.089	1.046	TRANSIENT WITH PCS UNAVAILABLE INITIATOR	Y	7	
%TSW	1.084	1.160	INITIATOR FLAG FOR LOSS OF SERVICE WATER IE-TSW	Y	1	Associated with cutsets related to MCR ventilation.
MFW-XHE-FO-COND	1.080	1.029	OPERATOR FAILS TO ESTABLISH FW OR CONDENSATE TO SG'S	Y	7	
SWS-STR-PG-DF06	1.077	1.028	COMMON CAUSE FAILURE 6 OF 6 STRAINERS ON ANNUAL BASIS	Y	1	
G2SW22	1.076	1.274	INSUFF FLOW FROM SW HDR 22	Y	9	
%TES	1.064	1.074	LOOP Initiator - switchyard / plant	Y	2	
%TEW	1.061	1.069	LOOP initiator - weather	Y	2	
RHS-XHE-FO-RECIR	1.056	1.030	U1 OPERATOR FAILS TO REALIGN FOR RECIRC	Y	7	
DGS-DGN-FR-DG1A	1.048	1.019	DGN-1A FAILURE TO RUN	Y	3	
RCS-XHE-FO-CLDWN	1.048	1.026	OPER FAILS TO COOLDOWN AND DEPRESSURIZE	Y	10	
RBU1_182	1.043	Not Previously Evaluated	AC nrec SBO w AFW success CD success 182 or 76 gpm seal LOCA	Y	2	
RDW-STR-PG-FLOOD2	1.042	1.020	Failure of drains (limited number)	Y	12	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
RCS-XHE-FO-LDEP	1.041	1.019	OPER FAILS TO DEPRESSUR RCS LATE	Y	13	
DGS-DGN-FR-DG1B	1.039	1.018	DGN-1B FAILURE TO RUN	Y	4	
%TEG	1.039	1.039	LOOP initiator - Grid	Y	3	
%TCC	1.039	1.021	INITIATOR FLAG FOR LOSS OF COMPONENT COOLING WATER IE-TCC	Y	10	
%TA	1.035	1.016	ATWS INITIATOR	Y	14	
RD-ABV	1.033	1.009	Fail to Provide Alternate Cooling by Opening Door/Using Portable Fan	Y	1	
RD4-XHE	1.031	1.014	FAIL TO OPEN DOORS /USE FANS FOR LOSS OF SWGR HVAC	Y	16	
%VSW	1.030	1.014	Initiator Flag for Loss of VSW IE	Y	16	
%FL_AB084B_M_FP	1.030	1.015	Flood AB 084 B Major, fire protection source	Y	12	
RD3-XHE-ABCAV	1.030	1.085	FAIL TO ALIGN CAV FOR AB-CAV MODE	Y	1	
CVS-XHE-FO-SOVCT	1.028	1.016	OP FAILS TO ISOLATE LETDOWN, TRANSFER CHG SUCTION, AND USE CCPS	Y	15	
CE	1.028	1.013	ELECTRICAL RPS FAILURE (ATWS)	Y	14	
RECOV0AB	1.028	1.013	Dependency adjust	Y	7	Associated with cutsets related to loss of AFW suction source.
%S4-C	1.027	1.015	STEAM GENERATOR 13 TUBE RUPTURE INITIATOR	Y	13	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
RECOV0	1.027	1.006	Dependency adjust	Y	7	Associated with cutsets related to loss of AFW suction source.
%FL_AB084B_G_FP	1.027	1.012	Flood AB 084 B General, fire protection source	Y	12	
RBU2	1.026	1.006	AC nrec w AFW success and no cooldown	Y	2	
X1-XHE-REC	1.026	1.006	FAIL TO DEPRESS W/I 2 HRS DURING SBO	Y	2	
RHR-XHE-FO-SHDCL	1.026	1.012	FAILURE OF OPERATOR TO ALIGN SHUTDOWN COOLING AFTER DEPRESS	Y	13	
%S4-D	1.025	1.015	STEAM GENERATOR 14 TUBE RUPTURE INITIATOR	Y	13	
%S4-A	1.025	1.015	STEAM GENERATOR 11 TUBE RUPTURE INITIATOR	Y	13	
MFI-UNAVAILABLE	1.025	1.012	Split Fraction for MFW Unavailable	Y	14	
%TDCA	1.025	1.015	LOSS OF 125V DC BUS A INITIATOR	Y	7	
ISG-XHE-SG-ISOL	1.024	1.011	SGTR ISOLATE AFFECTED STEAM GENERATOR	Y	13	
%S4-B	1.024	1.014	STEAM GENERATOR 12 TUBE RUPTURE INITIATOR	Y	13	
RECRBU1W182	1.022	Not Previously Evaluated	AC pwr nrec AFW and cooldn success, wx LOOP, 182gpm sl	Y	2	
RECOV10	1.022	1.011	Dependency adjust	Y	7	
%FL_AB045_SP	1.022	1.010	Flood AB045 spray all sources	Y	19	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
CCS-HTX-PG-1YEAR	1.021	1.013	HEAT EXCHANGER 11/12 TUBE PLUGGING	Y	10	
RD3-XHE-ABCAV-2	1.021	Not Previously Evaluated	Fail to use high flow "once through" FICR cooling	Y	1	
RBU1	1.021	1.175	AC nrec SBO w afw success cd success	Y	2	
RECOV10A	1.019	1.009	Dependency adjust	Y	7	
RECOV3	1.019	1.009	Dependency adjust	Y	8	
%TCA	1.017	1.008	INITIATOR FLAG FOR LOSS OF CONTROL AIR IE-TCA	**N**	**N/A**	**SAMA 30**: Automate start of diesel-powered air compressor. Associated with event CAS-XHE-FO-CAE63.
AFS-TDP-FS-TDP13	1.016	1.006	TDP 13 FAILS TO START	Y	8	
DGS-DGN-FR-DG1C	1.016	1.002	DGN-1C FAILURE TO RUN	Y	2	
RCS-XHE-FO-EDEP	1.016	1.007	OPER FAILS TO DEPRESSURIZE RCS EARLY	Y	10	
ESF-ICC-TM-AMSAC	1.015	1.007	AMSAC UNAVAILABLE FOR MAINTENANCE	Y	14	
RD3-XHE-MM	1.015	1.051	FAIL TO ALIGN CAV FOR MAINTENANCE MODE	Y	1	
CCS-HTX-TM-CCS12	1.015	1.009	12 CCS HT EXCHG UNAVAIL DUE TO TEST AND MAINT	Y	10	Associated with cutsets related to fail to depressurize and RCP seal failure.
RECOV15	1.015	1.051	Dependency adjust	Y	1	
VCA-PND-OC-1CAA9A	1.014	1.007	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN annual	Y	1	Associated with cutsets related to MCR ventilation.

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
VCA-PND-OC-CA202A	1.014	1.007	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN	Y	1	Associated with cutsets related to MCR ventilation.
VCA-PND-OC-CA203A	1.014	1.007	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN	Y	1	Associated with cutsets related to MCR ventilation.
VCA-PND-OC-CAA12A	1.014	1.007	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN annual	Y	1	Associated with cutsets related to MCR ventilation.
VCA-PND-OC-CAA13A	1.014	1.007	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN	Y	1	Associated with cutsets related to MCR ventilation.
VCA-PND-OC-CAA14A	1.014	1.007	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN alannu	Y	1	Associated with cutsets related to MCR ventilation.
CCS-PSF-RP-1YEAR	1.014	1.006	LEAK / PIPE RUPTURE ON CCS IN ONE YEAR	Y	10	Associated with cutsets related to fail to depressurize and RCP seal failure.
CCS-XHE-FO-ISOLT	1.014	1.006	FAILURE TO ISOLATE LEAK / RECOVER SYSTEM	Y	10	Associated with cutsets related to fail to depressurize and RCP seal failure.
AFS-XHE-FO-TCA	1.013	1.006	OPERATOR FAILS TO LOCALLY CONTROL SG LEVEL	**N**	**N/A**	**SAMA 30**: Automate start of diesel-powered air compressor. Associated with CAS-XHE-FO-CAE63.
RHS-STR-PG-SUMP	1.013	1.006	SUMP STRAINER PLUGGED	Y	8	Associated with cutsets related to AFW failures.
AFS-AOV-CC-1DR6	1.013	1.006	FAILURE OF 1DR6 TO OPEN TO REFILL AFWST	Y	8	
AFS-XHE-FO-REC1	1.012	1.006	OPERATOR FAILS TO CLOSE AFW DISCHRG VALVES LOCALLY	Y	13	Associated with cutsets related to SGTR scenarios.
%FL_AB084C_M_SW	1.012	1.006	AB 084C Major Flood SW source 1.774e-5	Y	6	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
VSW-FNR-FR-SUP12A	1.012	1.006	SUPPLY FAN 1VHE 57 FAILS TO RUN annual	Y	16	Associated with cutsets related to loss of switchgear cooling.
%S1	1.012	1.006	INTERMEDIATE LOCA INITIATOR	**N**	**N/A**	**SAMA 31**: Fully automate swapover to sump recirculation. Associated with cutsets related to failure to switch to sump recirculation or sump strainer plugging.
DGS-DGN-FR-SBO	1.012	Not Previously Evaluated	SBO DG fails to run	Y	2	
PC4	1.012	1.003	PORVS FAIL TO RECLOSE (TDE)	Y	2	Associated with cutsets related to LOOP scenarios.
RBU3	1.012	1.003	AC nrec w AFW success and stuck open PORV	Y	2	
FL_XHE_AB084C_M	1.011	1.005	Failure to isolate AB 84 C Major Flood	Y	6	
RECOV6	1.011	1.005	Dependency adjust	Y	13	
RDW-STR-PG-FLOOD	1.011	1.005	Drains fail to remove flood water	Y	6	Associated with cutsets related to AB084C internal flood scenarios.
RHS-XHE-FO-RECR1	1.011	1.005	OPERATOR FAILS TO REALIGN FOR RECIRC-SHORT TIME	**N**	**N/A**	**SAMA 31**: Fully automate swapover to sump recirculation. Associated with cutsets related to failure to switch to sump recirculation or sump strainer plugging.
DGS-DGN-FS-DG1A	1.010	1.014	DGN-1A FAILURE TO START	Y	2	
RECOV0A	1.010	1.009	Dependency adjust	Y	7	
RBU4	1.010	1.006	AC nrec with AFW failure	Y	2	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
VDG-FNS-FS-VHE25	1.010	1.014	DG 1A ROOM SUPPLY FAN 1VHE25 FAILS TO START	Y	4	
VDG-FNS-FS-VHE28	1.010	1.014	DG 1A CONTROL ROOM SUPPLY FAN 1VHE28 FAILS TO START	Y	4	
SRV-PRV-CC-1PR2	1.010	1.005	1PR2 PORV FAILS TO OPEN	Y	8	Associated with cutsets related to AFW failures.
SRV-PRV-CC-DF01	1.010	1.005	CCF TO OPEN OF BOTH PORVS 1PR1 AND 1PR2	Y	8	Associated with cutsets related to AFW failures.
CAS-XHE-FO-CAE63	1.010	1.005	OPERATOR FAILS TO START DIESEL COMPRESSOR	**N**	**N/A**	**SAMA 30**: Automate start of diesel-powered air compressor.
CCS-XHE-FO-TRIP	1.010	1.005	OP FAILS TO TRIP RX AND RCPS AFTER A LOSS OF CCW	Y	10	Associated with cutsets related to fail to depressurize and RCP seal failure.
CVS-XHE-FO-BORAT	1.009	1.004	FAILURE TO INITIATE RAPID BORATION	Y	14	
SWS-STR-PG-DF01	1.009	1.005	COMMON CAUSE BLOCKAGE OF ALL SW DISCHARGE STRAINERS	Y	9	
XCOM-MF	1.009	1.004	adjust for Success Branch Data	Y	9	
SWS-XHE-FO-CCP	1.009	1.004	REALIGN CVCS AS REQUIRED UPON LOSS OF SW	Y	9	
RECOV20	1.008	1.004	Dependency adjust	Y	10	
FL_XHE_AB084B_M	1.008	1.005	Failure to isolate major flood in AB 084 B	Y	12	
%FL_AB100_G_CV	1.008	1.004	AB100 general flood CVCS	N	N/A	**SAMA 32**: Enhance flood detection for 100-foot el. of Aux. Building

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
FL_XHE_AB100_G	1.008	1.004	Failure to isolate CVCS general flood AB 100	N	N/A	**SAMA 32**: Enhance flood detection for 100-foot el. of Aux. Building
RECRBU1W	1.008	1.053	AC pwr nrec AFW and cooldn success, wx LOOP	Y	2	
SWS-XHE-FO-SWIXO	1.008	1.011	FAILURE TO MANUALLY CLOSE SW TURBINE HEADER VALVES	Y	2	
RECOV7	1.008	1.004	Dependency adjust	Y	10	
CHS-CHL-TM-NO23	1.008	1.023	CHILLER 23 UNAVAILABLE DUE TO TEST AND MAINT	Y	1	
CHS-CHL-TM-NO13	1.008	1.226	CHILLER NO 13 UNAVAILABLE DUE TO TM	Y	1	
DGS-DGN-FS-DG1B	1.007	1.014	DGN-1B FAILURE TO START	Y	2	
VSW-FNR-FR-DF01A	1.007	1.004	COMMON CAUSE FTR OF SUPPLY FANS VHE56/VHE57/VHE58 annual	Y	16	
ACP-XHE-FO-GTG	1.007	1.014	GTG UNAVAILABLE DUE TO OPERATOR FAILURE	Y	2	
DGS-DGN-FR-DF02	1.007	1.007	DEP FAIL TO RUN OF DGN-1A, DGN-1B	Y	2	
VDG-FNS-FS-VHE26	1.007	1.013	DG 1B ROOM SUPPLY FAN 1VHE26 FAILS TO START	Y	2	
VDG-FNS-FS-VHE29	1.007	1.013	DG 1B CONTROL ROOM SUPPLY FAN 1VHE29 FAILS TO START	Y	2	
%TNC	1.007	1.003	T-VCA (Transient W/O LOP followed by Loss of VCA) INIT EVENT FOR TNC EVENT TREE	Y	1	
VCA-FNR-FR-FAN13A	1.007	1.003	fan 13 ftr annual	Y	1	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
AFS-TDP-TM-TDP13	1.007	1.003	TDP-13 UNAVAILABLE DUE TO TM	Y	8	
CCW-XHE-FO-TRIP	1.007	1.003	Failure to Trip RCPs on Loss of CCW	Y	10	
RECRBU1S	1.007	1.043	AC pwr nrec AFW and cooldn success, swyd & plt LOOP	Y	2	
CM	1.007	1.003	MECHANICAL RPS FAIL URE (ATWS)	Y	8	
SRV-PRV-OO-1PR1	1.006	1.001	PORV 1PR1 STUCK OPEN	Y	2	
SRV-PRV-OO-1PR2	1.006	1.001	PORV 1PR2 STUCK OPEN	Y	2	
%S2	1.006	1.003	SMALL LOCA INITIATOR	Y	24, 20, 31	Automated swap to recirc (SAMA 31) would address a part of the SLOCA contributions, as well.
FL_XHE-AB084B_G	1.006	1.003	Failure to isolate general flood in AB 084 B	Y	6	
ACP-TAC-VF-500KV	1.006	1.006	500KV SWITHCHYARD FAULT ACP-TAC-VF-500KV	Y	2	
ACP-TFM-LP-1A240A	1.006	1.007	TRANSFORMER LOSS OF POWER	Y	2	
ACP-TFM-LP-1A480A	1.006	1.007	TRANSFORMER LOSS OF POWER	Y	2	
VCA-PND-CC-1CAA18	1.006	Not Prev. Evaluated	AIR-OPERATED DAMPER CAA18 FAILS TO OPEN	Y	1	
VCA-PND-CC-1CAA19	1.006	Not Prev. Evaluated	AIR-OPERATED DAMPER CAA19 FAILS TO OPEN	Y	1	
VCA-PND-CC-1CAA41	1.006	Not Prev. Evaluated	AIR-OPERATED DAMPER CAA41 FAILS TO OPEN	Y	1	
VCA-PND-CC-1CAA45	1.006	Not Prev. Evaluated	AIR-OPERATED DAMPER CAA45 FAILS TO OPEN	Y	1	

TABLE 5B-2A
LEVEL 1 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.1 RISK REDUCTION WORTH	DESCRIPTION	EXISTING APPLICABLE SAMA (Y OR N)	IDENTIFIED APPLICABLE SAMA	COMMENTS
VCA-PND-OO-1CAA5	1.006	Not Prev. Evaluated	AIR OPERATED DAMPER CAA% FAILS TO CLOSE	Y	1	

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
RRS-XHE-FO-SDRSP	1.438	1.192	FAILURE OF THE OPER TO SHUTDOWN FROM REMOTE SDP	Y	1	
%TVC	1.233	1.111	INITIATOR FLAG FOR LOSS OF CONTROL AREA HVAC IE-TVC	Y	1	
RD-ABV	1.198	1.033	Fail to Provide Alternate Cooling by Opening Door/Using Portable Fan	Y	1	
RCS-SLOCA-SPLIT	1.192	1.207	SPLIT FRACTION FOR SEAL LOCA AFTER LOSS COOLING	Y	6	
RDW-STR-PG-FLOOD2	1.184	1.042	Failure of drains (limited number)	Y	12	
%TSW	1.173	1.084	INITIATOR FLAG FOR LOSS OF SERVICE WATER IE-TSW	Y	1	
SWS-STR-PG-DF06	1.158	1.077	COMMON CAUSE FAILURE 6 OF 6 STRAINERS ON ANNUAL BASIS	Y	1	
G2SW22	1.154	1.076	INSUFF FLOW FROM SW HDR 22	Y	9	
%FL_AB084B_M_FP	1.126	1.030	Flood AB 084 B Major, fire protection source	Y	12	
%TES	1.113	1.064	LOOP Initiator - switchyard / plant	Y	2	
%TEW	1.113	1.061	LOOP initiator - weather	Y	2	
%FL_AB084B_G_FP	1.110	1.027	Flood AB 084 B General, fire protection source	Y	12	
DGS-DGN-FR-DG1A	1.093	1.048	DGN-1A FAILURE TO RUN	Y	3	
RBU1_182	1.082	1.043	AC nrec SBO w AFW success CD success 182 or 76 gpm seal LOCA	Y	2	
DGS-DGN-FR-DG1B	1.074	1.039	DGN-1B FAILURE TO RUN	Y	4	

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
%TEG	1.064	1.039	LOOP initiator - Grid	Y	3	
AFS-MDP-FS-DF04	1.061	1.117	DEPEN FAILURE OF 3 AFW PUMPS (STEAM BINDING)	Y	8	
RD4-XHE	1.060	1.031	FAIL TO OPEN DOORS /USE FANS FOR LOSS OF SWGR HVAC	Y	16	
%VSW	1.059	1.030	Initiator Flag for Loss of VSW IE	Y	16	
RD3-XHE-ABCAV	1.057	1.030	FAIL TO ALIGN CAV FOR AB-CAV MODE	Y	1	
RBU2	1.050	1.026	AC nrec w AFW success and no cooldown	Y	2	
X1-XHE-REC	1.050	1.026	FAIL TO DEPRESS W/I 2 HRS DURING SBO	Y	2	
RECRBU1W182	1.043	1.022	AC pwr nrec AFW and cooldn success, wx LOOP, 182gpm sl	Y	2	
RD3-XHE-ABCAV-2	1.040	1.021	Fail to use high flow "once through" FICR cooling	Y	1	
AFS-XHE-FO-H2OLT	1.037	1.169	Failure to provide alternate suction source for AFW	Y	7	
RBU1	1.037	1.021	AC nrec SBO w afw success cd success	Y	2	
FL_XHE_AB084B_M	1.033	1.008	Failure to isolate major flood in AB 084 B	N	N/A	SAMA 12 applies to this event
RCS-HOTLEG	1.031	Not included in L1 importance list	PROB OF HOT LEG / SURGE LINE FAILURE PRIOR TO VESSEL BREACH	N	N/A	SAMA 12 applies to this event
%FL_AB084C_G_SW	1.030	1.135	General Flood Aux Bldg 84C Service Water	Y	6	
DGS-DGN-FR-DG1C	1.029	1.016	DGN-1C FAILURE TO RUN	Y	2	
AFS-TDP-FS-TDP13	1.029	1.016	TDP 13 FAILS TO START	Y	8	
RD3-XHE-MM	1.028	1.015	FAIL TO ALIGN CAV FOR MAINTENANCE MODE	Y	1	

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
RECOV15	1.028	1.015	Dependency adjust	Y	1	
VCA-PND-OC-1CAA9A	1.027	1.014	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN annual	Y	1	
VCA-PND-OC-CA202A	1.027	1.014	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN	Y	1	
VCA-PND-OC-CA203A	1.027	1.014	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN	Y	1	
VCA-PND-OC-CAA12A	1.027	1.014	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN annual	Y	1	
VCA-PND-OC-CAA13A	1.027	1.014	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN	Y	1	
VCA-PND-OC-CAA14A	1.027	1.014	AIR-OPERATED DAMPER FAILS TO REMAIN OPEN alannu	Y	1	
FL_XHE_AB084C_G	1.027	1.123	Operator fails to isolate flood source	Y	6	
%TT	1.026	1.101	TRANSIENT WITH PCS AVAILABLE INITIATOR	Y	7	
FL_XHE-AB084B_G	1.024	1.006	Failure to isolate general flood in AB 084 B	N	N/A	SAMA 12 applies to this event
VSW-FNR-FR-SUP12A	1.023	1.012	SUPPLY FAN 1VHE 57 FAILS TO RUN annual	Y	16	
AFS-XHE-FO-REFIL	1.023	1.118	FAILURE TO REFILL AFWST via DR6	Y	7	
PC4	1.022	1.012	PORVS FAIL TO RECLOSE (TDE)	Y	2	
RBU3	1.022	1.012	AC nrec w AFW success and stuck open PORV	Y	2	
DGS-DGN-FR-SBO	1.021	1.012	SBO DG fails to run	Y	2	
RECOV10	1.020	1.022	Dependency adjust	Y	7	

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
DGS-DGN-FS-DG1A	1.019	1.010	DGN-1A FAILURE TO START	Y	2	
VDG-FNS-FS-VHE25	1.019	1.010	DG 1A ROOM SUPPLY FAN 1VHE25 FAILS TO START	Y	4	
VDG-FNS-FS-VHE28	1.019	1.010	DG 1A CONTROL ROOM SUPPLY FAN 1VHE28 FAILS TO START	Y	4	
RBU4	1.018	1.010	AC nrec with AFW failure	Y	2	
%TP	1.018	1.089	TRANSIENT WITH PCS UNAVAILABLE INITIATOR	Y	7	
SWS-STR-PG-DF01	1.017	1.009	COMMON CAUSE BLOCKAGE OF ALL SW DISCHARGE STRAINERS	N	N/A	SAMA 9 applies to this event
SWS-XHE-FO-CCP	1.016	1.009	REALIGN CVCS AS REQUIRED UPON LOSS OF SW	N	N/A	SAMA 9 applies to this event
RECRBU1W	1.015	1.008	AC pwr nrec AFW and cooldn success, wx LOOP	N	N/A	SAMA 2 applies to this event
CHS-CHL-TM-NO23	1.015	1.008	CHILLER 23 UNAVAILABLE DUE TO TEST AND MAINT	N	N/A	SAMA 1 applies to this event
VSW-FNR-FR-DF01A	1.014	1.007	COMMON CAUSE FTR OF SUPPLY FANS VHE56/VHE57/VHE58 annual	N	N/A	SAMA 16 applies to this event
CHS-CHL-TM-NO13	1.014	1.008	CHILLER NO 13 UNAVAILABLE DUE TO TM	N	N/A	SAMA 1 applies to this event
SWS-XHE-FO-SWIXO	1.014	1.008	FAILURE TO MANUALLY CLOSE SW TURBINE HEADER VALVES	N	N/A	SAMA 2 applies to this event
DGS-DGN-FR-DF02	1.014	1.007	DEP FAIL TO RUN OF DGN-1A, DGN-1B	N	N/A	SAMA 2 applies to this event
%TNC	1.014	1.007	T-VCA (Transient W/O LOP followed by Loss of VCA) INIT EVENT FOR TNC EVENT TREE	N	N/A	SAMA 1 applies to this event

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
VCA-FNR-FR-FAN13A	1.014	1.007	fan 13 ftr annual	N	N/A	SAMA 1 applies to this event
DGS-DGN-FS-DG1B	1.014	1.007	DGN-1B FAILURE TO START	N	N/A	SAMA 2 applies to this event
VDG-FNS-FS-VHE26	1.013	1.007	DG 1B ROOM SUPPLY FAN 1VHE26 FAILS TO START	N	N/A	SAMA 2 applies to this event
VDG-FNS-FS-VHE29	1.013	1.007	DG 1B CONTROL ROOM SUPPLY FAN 1VHE29 FAILS TO START	N	N/A	SAMA 2 applies to this event
ACP-XHE-FO-GTG	1.013	1.007	GTG UNAVAILABLE DUE TO OPERATOR FAILURE	N	N/A	SAMA 3 applies to this event
RECRBU1S	1.012	1.007	AC pwr nrec AFW and cooldn success, swyd & plt LOOP	N	N/A	SAMA 2 applies to this event
AFS-TDP-TM-TDP13	1.012	1.007	TDP-13 UNAVAILABLE DUE TO TM	N	N/A	SAMA 8 applies to this event
ACP-TFM-LP-1A240A	1.011	1.006	TRANSFORMER LOSS OF POWER	N	N/A	SAMA 16 applies to this event
ACP-TFM-LP-1A480A	1.011	1.006	TRANSFORMER LOSS OF POWER	N	N/A	SAMA 16 applies to this event
VCA-PND-CC-1CAA18	1.011	1.006	AIR-OPERATED DAMPER CAA18 FAILS TO OPEN	N	N/A	SAMA 1 applies to this event
VCA-PND-CC-1CAA19	1.011	1.006	AIR-OPERATED DAMPER CAA19 FAILS TO OPEN	N	N/A	SAMA 1 applies to this event
VCA-PND-CC-1CAA41	1.011	1.006	AIR-OPERATED DAMPER CAA41 FAILS TO OPEN	N	N/A	SAMA 1 applies to this event
VCA-PND-CC-1CAA45	1.011	1.006	AIR-OPERATED DAMPER CAA45 FAILS TO OPEN	N	N/A	SAMA 1 applies to this event

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
VCA-PND-OO-1CAA5	1.011	1.006	AIR OPERATED DAMPER CAA% FAILS TO CLOSE	N	N/A	SAMA 1 applies to this event
SRV-PRV-OO-1PR1	1.011	1.006	PORV 1PR1 STUCK OPEN	N	N/A	SAMA 2 applies to this event
SRV-PRV-OO-1PR2	1.011	1.006	PORV 1PR2 STUCK OPEN	N	N/A	SAMA 2 applies to this event
ACP-TAC-VF-500KV	1.010	1.006	500KV SWITHCHYARD FAULT ACP-TAC-VF-500KV	N	N/A	SAMA 2 applies to this event
PI-SGTR-OPDEP	1.010	Not included in L1 importance list	PROB OF PRESSURE INDUCED SGTR WITH OPERATOR DEPRESSURIZATION	N	N/A	SAMA 6 applies to this event
CHS-CHL-FR-NO11A	1.010	1.005	CHILLER FAILS TO CONTINUE OPERATING annual	N	N/A	SAMA 1 applies to this event
ACP-BKR-CC-13ASD	1.009	1.005	BREAKER 13ASD FAILS TO OPEN ACP-BKR-CC-13ASD	N	N/A	SAMA 2 applies to this event
ACP-BKR-OO-1ADD	1.009	1.005	BREAKER-1ADD FAILS TO CLOSE	N	N/A	SAMA 2 applies to this event
XHOS-SUMMER	1.009	1.005	CONDITION FOR 3 SWP XHOS = 1: 3 SWP ARE RUNNING. ELSE = 0	N	N/A	SAMA 2 applies to this event
DGS-DGN-TM-DG1A	1.009	1.005	DGN-1A UNAVAILABLE DUE TO TM	N	N/A	SAMA 2 applies to this event
VCA-PND-CC-1CAA7	1.009	1.005	DAMPER 1CAA7 FAILS TO OPEN,	N	N/A	SAMA 1 applies to this event
AFS-TDP-FR-TDP13	1.009	1.005	TDP 13 FAILS TO RUN	N	N/A	SAMA 8 applies to this event
VSW-FNR-TM-SUP13	1.009	1.005	VSW SUPPLY FAN #13 UNAVAILABLE DUE TO TM	N	N/A	SAMA 16 applies to this event

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
RECRBU4G	1.008	1.004	AC pwr nrec AFW failure, grid LOOP	N	N/A	SAMA 2 applies to this event
DGS-DGN-FS-DG1C	1.008	1.004	DGN-1C FAILURE TO START	N	N/A	SAMA 2 applies to this event
ACP-BAC-TM-4KV1B	1.007	1.005	4160V AC VITAL BUS 1B OUT FOR TM	N	N/A	SAMA 2 applies to this event
VDG-FNS-FS-VHE27	1.007	1.004	DG 1C ROOM SUPPLY FAN 1VHE27 FAILS TO START	N	N/A	SAMA 2 applies to this event
VDG-FNS-FS-VHE30	1.007	1.004	DG 1C CONTROL ROOM SUPPLY FAN 1VHE30 FAILS TO START	N	N/A	SAMA 17 applies to this event
CHS-CHL-FR-NO21	1.007	1.004	CHILLER 21 FAILS TO RUN	N	N/A	SAMA 1 applies to this event
CHS-CHL-FR-NO22	1.007	1.004	CHILLER 22 FAILS TO RUN	N	N/A	SAMA 1 applies to this event
%S4-C	1.007	1.027	STEAM GENERATOR 13 TUBE RUPTURE INITIATOR	Y	13	
%S4-D	1.007	1.025	STEAM GENERATOR 14 TUBE RUPTURE INITIATOR	Y	13	
AFS-AOV-CC-1DR6	1.007	1.013	FAILURE OF 1DR6 TO OPEN TO REFILL AFWST	Y	8	
SWS-STR-PG-DF00	1.007	1.004	CCF OF ALL SWS STRAINERS (BOTH UNITS) ON ANNUAL BASIS	N	N/A	SAMA 9 applies to this event
CIS-PREEXIST	1.007	Not included in L1 importance list	PRE-EXISTING CONTAINMENT LEAK	N	N/A	SAMA 6 applies to this event

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
ACP-BKR-CC-14BSD	1.007	1.004	BREAKER-14BSD FAILS TO OPEN	N	N/A	SAMA 2 applies to this event
DGS-DGN-TM-DG1B	1.007	1.004	DGN-1B UNAVAILABLE DUE TO TM	N	N/A	SAMA 2 applies to this event
ACP-XHE-EXTENSBO	1.007	1.004	OPS FAIL TO ALIGN SBO DG FOR AFW AND SWITCHYARD SUPPORT	N	N/A	SAMA 2 applies to this event
VSW-FNR-TM-EXH12	1.007	1.003	12 SWGR EXH/RETURN FAN 1VHE1013 OUT FOR T&M	N	N/A	SAMA 17 applies to this event
ACP-BKR-OO-1BDD	1.007	1.004	BREAKER-1BDD FAILS TO CLOSE	N	N/A	SAMA 2 applies to this event
VSW-FNR-TM-12PEN	1.007	1.003	12 PEN AREA EXH FAN OUT FOR TM	N	N/A	SAMA 16 applies to this event
ACP-BAC-TM-4KV1C	1.006	1.003	4160V AC VITAL BUS 1C OUT FOR TM	N	N/A	SAMA 2 applies to this event
ACP-GTS-TM-GTG	1.006	1.004	GAS TURBINE GEN UNAVAIL DUE TO TM	N	N/A	SAMA 8 applies to this event
RCS-XHE-FO-LDEP	1.006	1.041	OPER FAILS TO DEPRESSUR RCS LATE	Y	13	
VCS-FNR-TM-VHE17	1.006	1	13 CFCU OUT FOR TM	N	N/A	SAMA 8 applies to this event
VCS-FNR-TM-VHE19	1.006	1	FAN UNIT 15 OUT FOR MAINTENANCE	N	N/A	SAMA 8 applies to this event
AFS-XHE-FO-SCRUB	1.006	Not included in L1 importance list	OPERATOR FAILS TO FILL RUPTURED SG TO SCRUB RELEASE	N	N/A	SAMA 13 applies to this event
AFS-XHE-FO-DOOR	1.006	1.003	Oper fails to open TDAFW pump room door	N	N/A	SAMA 8 applies to this event
VCS-FNR-TM-VHE18	1.006	1	FAN UNIT 14 OUT FOR MAINTENANCE	N	N/A	SAMA 8 applies to this event

TABLE 5B-2B
LEVEL 2 BASIC EVENT IMPORTANCE LIST SUMMARY FOR MOR REV. 4.3 MODEL

PRA BASIC EVENT NAME	MOR REV. 4.3 RISK REDUCTION WORTH	MOR REV. 4.3 CORRESPONDING LEVEL 1 RISK REDUCTION WORTH	DESCRIPTION	EVALUATED IN LEVEL 1 LISTING (Y OR N)	APPLICABLE SAMA IDENTIFIED FROM LEVEL 1 LIST	COMMENTS
ACP-OFFSITE-PWR	1.006	1.003	POWER UNAVAILABLE TO 500 KV SWITCHYARD	N	N/A	SAMA 2 applies to this event
VDG-PND-CC-1DGV2	1.006	1.003	EXHAUST DAMPER 1DGV2 FAILS TO OPEN	N	N/A	SAMA 2 applies to this event
VDG-PND-CC-DGV10	1.006	1.003	D/G 1A AREA VENTIL INTAKE DAMPER 2DGV10 FAIL TO OPEN	N	N/A	SAMA 2 applies to this event
VDG-PND-CC-V590	1.006	1.003	EXHAUST DAMPER 1VHE590 FAILS TO OPEN	N	N/A	SAMA 2 applies to this event
%S4-A	1.006	1.025	STEAM GENERATOR 11 TUBE RUPTURE INITIATOR	Y	13	

REFERENCES

EPRI 1995 EPRI (Electric Power Research institute). 1995. *PSA Applications Guide*. EPRI TR-105396, Final Report. D.E. True. August.

5.c Table E.5-1 describes SAMA 8, installing a high pressure pump powered with portable diesel generator, as a way to reduce the risk associated with Event AFS-MDP-FS-DF04: "Dependent failure of 3 AFW Pumps (Steam binding)". The table indicates that the contribution from this particular failure could potentially be reduced by operating with the "AF11/21" valves closed but that a more comprehensive enhancement would be a portable diesel driven pump (i.e. SAMA 8). Section E.6.8.3 presents an estimated unit cost for SAMA 8 of $2.5M and concludes that SAMA 8 is not cost beneficial. The cost of operating with the "AF11/21" valves would appear to be much lower than $2.5M. Provide a cost-benefit evaluation of a SAMA to operate with the AF11/21 valves closed as a lower cost alternative to SAMA 8.

PSEG Response:

Although operation with the AF11/21 valves would theoretically provide a robust barrier against the steam binding of all three AFW pumps, it would not necessarily be a feasible option as it would affect other design-basis calculations and assumptions with regard to delivering auxiliary feedwater to the steam generators. The actual plant configuration for SGS is such that the discharge valves on the motor-driven AFW pumps (AF21 valves) are already shut, but the valves on the discharge side of the turbine-driven AFW pump (AF11 valves) are open. This presents a condition in which it could theoretically be possible for the phenomenon to occur by which high temperature water leaks by a series of check valves to cause steam binding of the common suction line for all three AFW pumps. However, upon closer inspection, this leakage would have to be experienced by three separate check valves before the common suction line to the AFW pumps would be affected.

The industry reference used for this common-cause steam binding of all three pumps appears to be artificially high for the Salem plant configuration, and is thus partly responsible for this event appearing above the RRW threshold of 1.01. However, in reality its importance is being overstated and the idea of postulating a SAMA in which the four discharge valves from the turbine-driven AFW pump were to be maintained shut could have an unintended adverse impact on the design-basis for the Salem plant. Therefore, it is not feasible and considered unnecessary to provide a cost-benefit evaluation for a SAMA to operate with both the AF11 and AF21 valves shut, as it could arguably provide a negative risk benefit given that the AFW air-operated discharge valves could then experience a common-cause failure to open. In effect, this alternative SAMA that is being proposed could present a new failure mechanism that is similar to what was originally being mitigated, i.e., failure of all three AFW pumps to deliver water to the steam generators.

5.d Table E.5-1 identifies several events beginning with the symbol "%" as either initiators or flags for initiators, and proposes SAMAs for both kinds of events. Clarify why SAMAs were proposed for "flags for initiators". If the initiator flags are meant to be surrogates for the actual initiator clarify why a value of 1.0 is the appropriate probability on which to base the importance analysis.

PSEG Response:

Most initiators in the Salem model were represented by a single numeric value, which was developed using both generic industry and plant-specific data that was applied to special basic-event logic elements. For example, this was the case for the Large Loss of Coolant (LOCA) initiator. However a number of initiating events were developed using fault trees. Fault trees were constructed to model the initiating event frequency for several loss of support system initiating events. Those events that lead to the loss of a support system and are responsible for causing the modeled initiating event were identified in cutsets with a type of flag event preceded by the "%" symbol. These %-flag events that are listed in the importance list ranking are representative of that particular initiating event's contribution to CDF and are appropriate for risk ranking. Events whose failure leads to the occurrence of the modeled initiating event also will be listed in the importance list ranking since they will be a constituent part of those cutsets that yield core damage. The flag event merely serves to identify that a failure of the system associated with the initiating event has occurred. To avoid altering the CDF contribution of the cutset(s) the flag probability was set to 1.0. Therefore, the Fussell-Vesely for an initiating event flag correctly measures the risk significance of the initiating event modeled in this manner.

5.e Table E.5-1 identifies two events that are split fractions (i.e. RCS-SLOCA-SPLIT: "Split fraction for seal LOCA after cooling" with a probability of 1.0, and MFI-UNAVIALABLE: "Split fraction for MFW unavailable" with a probability of 0.3). Describe the significance of the SAMAs proposed for these events.

PSEG Response:

The event RCS-SLOCA-SPLIT is a flag event that indicates those cutsets whereby a RCP seal LOCA has occurred as part of the accident scenario. Hence, because it is a flag event, it was assigned a probability of 1.0. This event was assigned to SAMA 6, which involved a SW break in the Auxiliary Building that leads to an eventual RCP seal LOCA. Therefore, the significance of the identified SAMA is such that isolating the SW rupture early could help prevent the conditions that can result in the occurrence of an RCP seal LOCA.

The event MFI-UNAVAILABLE is the conditional probability that the main feedwater system is unavailable given that a reactor trip signal has been generated, irrespective of whether an ATWS condition exists. This conditional probability was assigned a value of 0.30. Hence, a SAMA was identified to use the AMSAC system to provide a redundant trip signal to help mitigate these ATWS events, since core damage results due to main feedwater being unavailable to remove excess heat generated in the reactor core from the primary system.

5.f PSEG's review of Phase 2 SAMAs from prior SAMA submittals appears to have overlooked additional potentially cost-beneficial SAMAs identified during the NRC staff's review of the referenced plants, for example, Point Beach SAMA 169, "provide portable generators to be hooked up to turbine driven AFW after battery depletion," and use of a gagging device to remotely close a stuck open safety valve on a ruptured steam generator at Prairie Island. For these and any other additional cost-beneficial SAMAs, provide an assessment of their applicability to SNGS, and a cost-benefit evaluation for any SAMA determined to be applicable.

PSEG Response:

As part of the SAMA identification process, SGS reviewed the cost beneficial SAMAs identified in Environmental Report (ER) submittals of the following six plants:

- Susquehanna
- Shearon Harris
- H.B. Robinson
- Point Beach
- Prairie Island
- Wolf Creek

However, the final determination of the cost beneficial SAMAs for a given plant is documented in the plant specific supplements of NUREG-1437. In order to provide a complete review of the cost beneficial SAMAs for the plants SGS designated for review, any additional cost beneficial SAMAs that were identified in NUREG-1437 have been addressed below.

<u>Susquehanna</u>

NUREG-1437 Supplement 35 (NRC 2009a) was reviewed and no additional, cost beneficial SAMAs were identified beyond those that were considered in the SGS ER.

<u>Shearon Harris</u>

NUREG-1437 Supplement 33 (NRC 2008a) was reviewed and no additional, cost beneficial SAMAs were identified beyond those that were considered in the SGS ER.

<u>H.B. Robinson</u>

NUREG-1437 Supplement 13 (NRC 2003) was reviewed and two cost beneficial SAMAs were identified that were not included in the SGS review of industry SAMAs. The following table identifies these SAMAs and provides their dispositions for SGS:

REVIEW OF ADDITIONAL H.B. ROBINSON COST BENEFICIAL SAMAS FROM NUREG-1437

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR SGS	DISPOSITION FOR SGS SAMA LIST
NA	Modification of RHR valve yokes to reduce the risk from seismically induced interfacing system LOCAs	In general, the system valves at SGS were screened in the seismic PRA based on high seismic ruggedness. The plant seismic walkdown reviews specifically included a review of the valve yokes. No vulnerabilities were found and no yoke failures were identified as important seismic contributors.	Not required for the SGS SAMA evaluation.
NA	Installation of a radiant heat shield on the dedicated shutdown diesel generator electrical conduit to reduce risk from fire induced SBOs	The plant enhancement proposed for Robinson is based on a very specific risk associated with the Robinson plant configuration and its fire model. While an exact match of the Robinson vulnerability does not exist at SGS, fires in the 4160V AC Switchgear Room can result in an SBO if the fires propagate from their ignition sources. Fire barriers were suggested to address this risk in the SGS ER submittal, which is considered to appropriately address the SGS fire risk. No additional SAMAs are required.	Already included on the SGS SAMA list.

<u>Point Beach</u>

NUREG-1437 Supplement 23 (NRC 2005) was reviewed and one cost beneficial SAMA was identified that was not included in the SGS review of industry SAMAs. The following table identifies this SAMA and provides its disposition for SGS:

REVIEW OF ADDITIONAL POINT BEACH COST BENEFICIAL SAMAS FROM NUREG-1437

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR SGS	DISPOSITION FOR SGS SAMA LIST
169	Provide portable generators to be hooked up to turbine driven AFW pump following battery depletion	This SAMA was identified as a SAMA candidate for SGS (SAMA 5A).	Already implemented.

Prairie Island

NUREG-1437 Supplement 39 (NRC 2009b) was reviewed and three cost beneficial SAMAs were identified that were not included in the SGS review of industry SAMAs. The following table identifies these SAMAs and provides their disposition for SGS:

REVIEW OF ADDITIONAL PRAIRIE ISLAND COST BENEFICIAL SAMAS FROM NUREG-1437

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR SGS	DISPOSITION FOR SGS SAMA LIST
3	Provide alternate flow path from RWST to charging pump suction	The SGS RWST suction path to the CVCS already includes a pair of redundant valves and the RRW value of the event representing common cause failure of the valves is less than 1.001 (not a meaningful contributor to risk).	Already implemented.

REVIEW OF ADDITIONAL PRAIRIE ISLAND COST BENEFICIAL SAMAS FROM NUREG-1437

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR SGS	DISPOSITION FOR SGS SAMA LIST
19a	Provide a reliable backup water source for replenishing the RWST	For PINGP, the installation of the RWST refill source is credited primarily for increasing the time that is available to perform the RCS cooldown in an SGTR. Cooldown would equalize primary and secondary side pressures and effectively terminate the inventory loss to the secondary side. Excluding any dependency issues between cooldown and RWST refill, extending the time available for successful cooldown would have a negligible impact on SGS risk. Cooldown in an SGTR is represented by two actions for SGS, RCS-XHE-FO-EDEP (early cooldown, before SVs pass water) and RCS-XHE-FO-LDEP (late cooldown, prior to RWST depletion). SAMA 19a would impact the late action (RCS-XHE-FO-LDEP); however, given that the cue for the action occurs at 1.4 hours and the RWST is not depleted until 13 hours, time is not an important issue for this action and the SAMA would not significantly impact SGS risk.	Would not impact SGS risk. Not required.

REVIEW OF ADDITIONAL PRAIRIE ISLAND COST BENEFICIAL SAMAS FROM NUREG-1437

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR SGS	DISPOSITION FOR SGS SAMA LIST
NA	Use of a "gagging device" to close stuck-open steam generator safety valves in SGTR events	A primary concern with the proposed SAMA is that a gagging device could typically not be operated during an SGTR event. Unlike Beaver Valley, where this SAMA was initially identified as potentially cost effective, SGS does not have primary loop isolation valves. At a minimum, SGTR conditions would present an extremely challenging working environment at the safety valve (heat, noise, radiation). Remote operation may be required to realistically credit re-closure of a safety valve during an SGTR event. With regard to the impact of the SAMA (assuming it could work), a stuck open safety valve is assumed to be a consequence of the failure to perform early cooldown. Once this occurs, late cooldown (before RWST depletion) is credited as a success path for effectively terminating the SGTR event (primary to secondary side flow becomes negligible). This occurs whether or not the stuck open safety valve is ever re-closed. In the event of a late cooldown failure, the action to gag the SG safety valve closed would be driven by the same cues, share very similar timing, and be performed as part of the same cooldown/recovery process; therefore, the actions would be completely dependent and no benefit would be realized. Further, because the SGS SGs have multiple safety valves, use of a gagging device could cause an undesirable complication in the cooldown process. Once the stuck open safety valve is gagged closed, the SGs will begin to re-pressurize and an additional safety valve would be forced open unless the cooldown action was performed rapidly (much sooner than the 13 hour window that is available for RWST depletion). Failure to cooldown rapidly could result in an additional stuck open SV.	Would not impact SGS risk. Not required.

Wolf Creek

NUREG-1437 Supplement 32 (NRC 2008b) was reviewed and no additional, cost beneficial SAMAs were identified beyond those that were considered in the SGS ER.

REFERENCES

NRC 2003 NRC (U.S. Nuclear Regulatory Commission). 2003. "Generic Environmental Statement for License Renewal of Nuclear Power Plants, Supplement 13, Regarding H.B. Robinson Steam Electric Plant, Unit No. 2". NUREG-1437. Final Report. December.

NRC 2005 NRC (U.S. Nuclear Regulatory Commission). 2005. "Generic Environmental Statement for License Renewal of Nuclear Power Plants, Supplement 23, Regarding Point Beach Nuclear Plants, Units 1 and 2". NUREG-1437. Final Report. August.

NRC 2008a NRC (U.S. Nuclear Regulatory Commission). 2008. "Generic Environmental Statement for License Renewal of Nuclear Power Plants, Supplement 33, Regarding Shearon Harris Nuclear Power Plant, Unit 1". NUREG-1437. Final Report. July.

NRC 2008b NRC (U.S. Nuclear Regulatory Commission). 2008. "Generic Environmental Statement for License Renewal of Nuclear Power Plants, Supplement 32, Regarding Wolf Creek Generating Station". NUREG-1437. Final Report. May.

NRC 2009a NRC (U.S. Nuclear Regulatory Commission). 2009. "Generic Environmental Statement for License Renewal of Nuclear Power Plants, Supplement 35, Regarding Susquehanna Steam Electric Station, Units 1 and 2". NUREG-1437. Final Report. March.

NRC 2009b NRC (U.S. Nuclear Regulatory Commission). 2009. "Generic Environmental Statement for License Renewal of Nuclear Power Plants, Supplement 39, Regarding Prairie Island Nuclear Generating Plant, Units 1 and 2". NUREG-1437. Final Report. October.

5.g SAMA 20, which involves installing a "fire safe" system to provide makeup to the RCS and steam generators, would reduce the risk associated with fire area 1FA-AB-84A: 460V Switchgear Rooms at a cost of $13M. SAMA 23, which involves providing separation between power divisions by installing barriers or wrap, would reduce the risk associated with fire area, 1FA-AB-64A: 4160 Switchgear Room at a far lower cost of $975K. Provide an evaluation of a SAMA to install improved fire barriers to provide separation between the three divisions as a lower cost alternative to SAMA 20.

PSEG Response:

While both the 1FA-AB-84A and 1FA-AB-64A fire areas include cross-divisional separation issues, the configuration of 1FA-AB-84A is significantly more complex than for 1FA-AB-64A. There are similarities in the types of enhancements that would be required in each of the two fire areas, but the scope of the changes needed to protect critical equipment in 1FA-AB-84A is much greater than what would be required for 1FA-AB-64A.

In addition, a graded approach was taken in the development of the implementation cost for SAMA 23 such that the cost of implementation does not address all fire risks for the area. The SGS IPEEE identified transient fires as one of the largest contributors to risk in 1FA-AB-64A; consequently, the initial step in the development of the implementation cost for 1FA-AB-64A was directed at preventing the spread of transient fires between divisions. The cost of implementation for SAMA 23 is based on the construction of division specific rooms to house the individual 4KV AC busses as an initial step in addressing the transient fires, but the design did not include any details related to protecting overhead cables. Because the preliminary cost of addressing the transient fires in 1FA-AB-64A was clearly greater than the potential averted cost-risk for all 1FA-AB-64A contributors, the SAMA 23 design was not developed in any further detail.

While a detailed implementation cost has not been developed to fully address risk in 1FA-AB-64A, PSEG estimates that the $975,000 implementation cost used for SAMA 23 may be at least an order of magnitude low. Further, the cost of addressing the risk in 1FA-AB-84A may be double what would be required for 1FA-AB-64A.

Based on the information provided in Section E.6.20.2 of the ER, the PACR for 1FA-AB-84A is $2,035,006. Even when accounting for the 95th percentile PRA results, the potential averted cost-risk (PACR) would only increase to $5,087,515 (2.5 * $2,035,006), which is a fraction of the cost that would be required to address the risk in 1FA-AB-84A.

As identified in the response to RAI 5.b, the PRA model was updated after the submittal of the ER. If the 1FA-AB-84A PACR is re-calculated using the PRA MOR Rev. 4.3 model, it is reduced from $2,035,006 to $1,379,931. This correlates to a 95th percentile PACR of only $3,449,828.

In conclusion, the implementation cost documented for SGS SAMA 23 was developed in a graded manner and is not directly applicable to fire area 1FA-AB-84A. While it may be possible to significantly reduce fire risk in 1FA-AB-84A through installation of fire barriers and cable wrap, the modifications would be extremely resource intensive, complex, and prove to not be cost beneficial.

5.h SAMA 8, which involves providing an engine driven, high pressure makeup pump for the steam generators, would reduce the risk associated with fire area 1FA-AB-84B: Reactor Plant Aux Equip Area at a cost of $2.5M. Provide an evaluation of a SAMA to install improved fire barriers to provide separation between the AFW pumps.

PSEG Response:

Of the fire scenarios evaluated for fire area 1FA-AB-84B, only 2 of the 17 scenarios include any significant contribution from failure of multiple AFW pumps:

- 1AF2: Ignition of either the 205 and 206 panels (AFW motor driven pump control) (2.5E-07)
- 1AF5: Ignition of either the #11 or #12 AFW pumps (4.9E-07)

Based on the PRA information provided in the ER, these two scenarios account for about 67 percent of the 1FA-AB-84B risk. Given that the baseline partial averted cost-risk (PACR) for the area is $173,528, the maximum averted cost risk for this type of SAMA would be $116,264, assuming that the SAMA was 100 percent effective. Accounting for the 95th percentile PRA results, this averted cost estimate would be increased by a factor of 2.5 to $290,660. When a relatively small contributor, such as 1FA-AB-84B, requires significant hardware modifications to mitigate risk, it is rare that a cost effective solution can be identified. In these circumstances, it is generally more cost effective to modify an existing SAMA to also address an additional area of concern than to develop a SAMA that only addresses the low risk area. This was the reason that SAMA 8 was identified for fire area 1FA-AB-84B.

If a SAMA were to be developed to address the risk from 1FA-AB-84B alone, at least two distinct enhancements would be required, one barrier between the motor driven AFW pumps themselves and an additional barrier within the local motor driven AFW pump control panels (205 and 206). The turbine driven AFW pump is located in a separate metal enclosure and is not susceptible to fires in either of the motor driven pumps or control panels.

While a cost estimate for these specific changes has not been developed, the implementation costs for similar SAMAs can be used as an approximation of the costs:

- For SAMA 22, the cost of improving the separation of 3 consoles in the MCR was $1,600,000. For a single console, the cost is divided by 3 to reflect installation of a single barrier between panels 205 and 206 ($533,333). Further, it is assumed the AFW local pump control panels are less complex and the cost is multiplied by 0.5 to reflect the reduced resources required to design and implement the changes ($266,667).
- For SAMA 23, the construction of fire barriers was proposed between the three emergency 4160V AC buses to prevent propagation between

divisions. It is assumed that a single barrier between the two motor driven AFW pumps can be constructed for half of the original cost of $975,000 per unit, or $487,500.

The cost of implementation is the sum of these two components, or $754,167, which yields a net value of -$463,507 ($290,660 - $754,167).

If the results from MOR Rev. 4.3 are used with the corrected net electric output value of 1195MWe, the PACR for 1FA-AB-84B is reduced to $117,669. The 1AF2 and 1AF5 scenarios contribute only $78,838 to this total given that they comprise only 67 percent of the 1FA-AB-84B CDF. Using the 95th percentile PRA results, the maximum averted cost-risk for the type of SAMA proposed in this RAI is $197,095. Assuming that the SAMA proposed in this RAI question is 100 percent effective, the net value would be -$557,072 ($197,095 - $754,167) using the cost of implementation estimated above.

5.i Table E.5-3 describes the source of SAMA 24 as the "SNGS IPEEE (Fire)." However, neither Section E.5.1.5 nor E.5.1.6 identify this SAMA from the review of the plant changes identified in the SNGS IPEEE or from the review of the SNGS IPEEE fire model, respectively. While the source of this SAMA appears to be the review of fire area 12FA-SW-90A/90B: Service Water Intake, SAMA 24 is assumed to only provide benefits in internal events. Clarify the source for SAMA 24 and the PRA model changes made to evaluate this SAMA.

PSEG Response:

SAMA 24 was identified as part of the internal events importance list review, as documented in Table E.5-1 (see events RRS-XHE-FO-SDRSP, %TSW, RD3-XHE-ABCAV, and RD3-XHE-MM).

The procedural guidance suggested in the SAMA to perform the inter-unit Service Water cross-tie is already in place for Fire events, so implementation would not provide any benefit for fire events. This is why there is no reduction in fire CDF for SAMA 24. The PRA model changes are as stated in section E.6.24.1.

6. Provide the following with regard to the Phase II cost-benefit evaluations:

6.a Section E.6 introduction states that plant personnel developed SNGS specific costs to implement each of the SAMAs. Provide a description of: the process PSEG used to develop the SAMA implementation costs, the level of detail used to develop the cost estimates (i.e., general cost categories), and how the calculations are documented.

PSEG Response:

Following initial development of the SAMAs, a series of meetings were held between the personnel responsible for the SAMA development and the two PSEG License Renewal Site Leads. The Site Leads are Engineering Managers and each have over 25 years of plant experience including over 10 years with PSEG Nuclear. This experience includes project management, operations, plant engineering, design engineering, procedure support, simulators, and training. The purpose of the meetings was to validate each SAMA against plant configuration and to develop an estimate of its implementation cost. In some instances, the Site Leads provided information that was used to refine the SAMA or to develop an alternate approach to reach the same objective at a lower implementation cost. At the conclusion of the series of meetings, the SAMAs were provided to the Design Engineering Manager for review and comment from both technical and cost perspectives. The SAMA information in the LRA reflects the final product of this process.

As shown in the following table, there are seven general cost categories. Costs are budgetary estimates, not detailed estimates. For some of these categories, the cost is shared equally between Salem 1 (S1) and Salem 2 (S2). In addition to the cost information, the table provides a summary of the SAMA changes. This table was prepared for each SAMA during the previously described series of meetings.

SAMA 3: INSTALL LIMITED EDG CROSS-TIE CAPABILITY BETWEEN SALEM 1 AND 2

	SHARED S1/S2	S1 ONLY	S2 ONLY
Engineering	$2,000,000	$0	$0
Material	$0	$1,000,000	$1,000,000
Installation	$0	$2,000,000	$2,000,000
Licensing	$0	$100,000	$100,000
Critical Path Impact	$0	$0	$0
Simulator Modification	$50,000	$0	$0
Procedures and Training	$100,000	$0	$0
S1 Cost	$4,175,000		
S2 Cost	$4,175,000		
Summary:			
This SAMA involves the installation of tie breakers, lines, and controls to allow for Emergency Diesel Generator (EDG) cross-ties from one Salem unit to the other Salem unit. The cross-tie capability will be limited to "A" and "B" train cross-ties (i.e. 1A to 2A, 2A to 1A, 1B to 2B, 2B to 1B). The cross-tie controls will be in the Control Room. This SAMA involves safety-related, permanent plant modifications.			

Safety-related modifications are significantly more expensive than other types of modifications. Permanent modifications are more expensive than temporary actions such as staging fans for usage during loss of HVAC.

With respect to the general category of “Procedures and Training”, the cost estimate considers the complexity of the SAMA. Some plant modifications, such as adding cross-tie capability for Emergency Diesel Generators, involve revisions to a large number of procedures, affect multiple groups (ex. Operations and I&C), and require significant training (ex. simulator, classroom, and field). Accordingly, the cost estimates are higher than a relatively simple procedure change such as one allowing an existing, non-Technical Specification procedure to be used under additional circumstances. A simple procedure change has a typical cost of $50,000.

6.b For certain Phase I SAMAs listed in Table E.5-3, the information provided does not sufficiently describe the associated modifications and what is included in the cost estimate. Provide a more detailed description of both the modification and the cost estimate for SAMAs 3, 5, 8, 13, 20, and 23.

PSEG Response:

A table was prepared for each SAMA that included cost estimates and a summary of the SAMA changes. These tables are provided for SAMAs 3, 5, 8, 13, 20, and 23.

SAMA 3: INSTALL LIMITED EDG CROSS-TIE CAPABILITY BETWEEN SALEM 1 AND 2			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$2,000,000	$0	$0
Material	$0	$1,000,000	$1,000,000
Installation	$0	$2,000,000	$2,000,000
Licensing	$0	$100,000	$100,000
Critical Path Impact	$0	$0	$0
Simulator Modification	$50,000	$0	$0
Procedures and Training	$100,000	$0	$0
S1 Cost	$4,175,000		
S2 Cost	$4,175,000		
Summary:			
This SAMA involves the installation of tie breakers, lines, and controls to allow for Emergency Diesel Generator (EDG) cross-ties from one Salem unit to the other Salem unit. The cross-tie capability will be limited to "A" and "B" train cross-ties (i.e. 1A to 2A, 2A to 1A, 1B to 2B, 2B to 1B). The cross-tie controls will be in the Control Room. This SAMA involves safety-related, permanent plant modifications.			

SAMA 5: INSTALL PORTABLE DIESEL GENERATORS TO CHARGE STATION BATTERY AND CIRCULATING WATER BATTERIES & REPLACE PDP WITH AIR-COOLED PUMP			
STATION BATTERY	**SHARED S1/S2**	**S1 ONLY**	**S2 ONLY**
Engineering	$300,000	$0	$0
Material	$0	$100,000	$100,000
Installation	$0	$200,000	$200,000
Licensing	$0	$50,000	$50,000
Critical Path Impact	$0	$0	$0
Simulator Modification	$20,000	$0	$0
Procedures and Training	$50,000	$0	$0
S1 Cost	$535,000		
S2 Cost	$535,000		
CIRCULATING WATER BATTERIES	**SHARED S1/S2**	**S1 ONLY**	**S2 ONLY**
Engineering	$100,000	$0	$0
Material	$0	$50,000	$50,000
Installation	$0	$100,000	$100,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$20,000	$0	$0
Procedures and Training	$50,000	$0	$0
S1 Cost	$235,000		
S2 Cost	$235,000		
PDP REPLACEMENT	**SHARED S1/S2**	**S1 ONLY**	**S2 ONLY**
Engineering	$800,000	$0	$0
Material	$0	$1,000,000	$1,000,000
Installation	$0	$1,000,000	$1,000,000
Licensing	$0	$100,000	$100,000
Critical Path Impact	$0	$0	$0
Simulator Modification	$50,000	$0	$0
Procedures and Training	$50,000	$0	$0

SAMA 5: INSTALL PORTABLE DIESEL GENERATORS TO CHARGE STATION BATTERY AND CIRCULATING WATER BATTERIES & REPLACE PDP WITH AIR-COOLED PUMP	
S1 Cost	$2,550,000
S2 Cost	$2,550,000
TOTAL	
S1 Cost	$3,320,000
S2 Cost	$3,320,000
Summary:	
This SAMA has three parts. The first one involves a portable diesel generator connected to a permanent battery charger to charge the station battery (AFW indications and controls). The second one involves replacement of the water-cooled PDP (Positive Displacement Pump) with an air cooled pump. The third one involves a portable diesel generator connected to a permanent battery charger to charge the Circulating Water batteries. This SAMA involves permanent plant modifications. The first two parts are also safety-related.	

SAMA 8: INSTALL HIGH PRESSURE PUMP POWERED WITH PORTABLE DIESEL GENERATOR TO SUPPLY THE AFW HEADER			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$800,000	$0	$0
Material	$0	$1,000,000	$1,000,000
Installation	$0	$1,000,000	$1,000,000
Licensing	$0	$50,000	$50,000
Critical Path Impact	$0	$0	$0
Simulator Modification	$20,000	$0	$0
Procedures and Training	$100,000	$0	$0
S1 Cost	$2,510,000		
S2 Cost	$2,510,000		
Summary:			
This SAMA involves the installation of a high pressure pump powered from a dedicated diesel generator and connected to the turbine-driven AFW header. The preferred makeup source is demineralized water. All components would be permanent installations. This SAMA involves safety-related, permanent plant modifications. This SAMA is similar to one at Brunswick.			

SAMA 13: INSTALL PRIMARY SIDE STEAM GENERATOR ISOLATION VALVES			
	SHARED S1/S2	S1 ONLY	S2 ONLY
Engineering	$5,000,000	$0	$0
Material	$0	$3,000,000	$3,000,000
Installation	$0	$2,000,000	$2,000,000
Licensing	$0	$100,000	$100,000
Critical Path Impact	$0	$10,000,000	$10,000,000
Simulator Modification	$100,000	$0	$0
Procedures and Training	$200,000	$0	$0
S1 Cost	$17,750,000		
S2 Cost	$17,750,000		
Summary:			
This SAMA installs primary-side steam generator isolation valves. This safety-related permanent modification has similarities with replacement of the steam generators with respect to Reactor Coolant System cuts and Critical Path cost during the outage.			

SAMA 20: INSTALL ADDITIONAL ECCS AND AFW TRAINS			
	SHARED S1/S2	S1 ONLY	S2 ONLY
Engineering	$8,000,000	$0	$0
Material	$0	$5,000,000	$5,000,000
Installation	$0	$4,000,000	$4,000,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$50,000	$0	$0
Procedures and Training	$150,000	$0	$0
S1 Cost	$13,100,000		
S2 Cost	$13,100,000		
Summary:			
This SAMA involves the installation of an independent system containing two high pressure pumps to provide makeup to the RCS and Steam Generators (i.e. a new ECCS train and a new AFW train). It is a safety-related, permanent plant modification.			

SAMA 23: SUB-DIVIDE 4160V AC SWITCHGEAR ROOM			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$600,000	$0	$0
Material	$0	$200,000	$200,000
Installation	$0	$400,000	$400,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$50,000	$0	$0
Procedures and Training	$100,000	$0	$0
S1 Cost	$975,000		
S2 Cost	$975,000		
Summary:			
This SAMA involves subdividing the 4160V AC Switchgear room into separate rooms, one for each division. In addition to walls and doors, modifications to ventilation, fire protection, and lighting would be required. It is a safety-related permanent plant modification including seismic considerations.			

6.c SAMAs 1 and 17 are similar in that each involves opening doors to provide ventilation and using portable fans to enhance natural circulation if required. However, the estimated implementation costs are significantly difference ($475K and $200K, respectively). Provide an explanation of the reasons for the differences in the cost estimates for these SAMAs.

PSEG Response:

A table was prepared for each SAMA that included cost estimates and a summary of the SAMA changes. These tables are provided for SAMAs 1 and 17. The summaries describe the rationale for the differing costs. SAMA 1 is more complicated because it involves the Control Room envelope and three rooms with differing requirements. SAMA 17 includes four, basically identical rooms. The differences in the cost estimates are justified.

SAMA 1: ENHANCE PROCEDURES AND PROVIDE ADDITIONAL EQUIPMENT TO RESPOND TO LOSS OF CONTROL AREA VENTILATION			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$100,000	$0	$0
Material	$0	$150,000	$150,000
Installation	$0	$200,000	$200,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$0	$0	$0
Procedures and Training	$150,000	$0	$0
S1 Cost	$475,000		
S2 Cost	$475,000		
Summary:			
There are three rooms involved in this SAMA: the Control Room, the Rack Room, and the Relay Room. The Engineering work includes the determination of the air flow paths from the respective rooms to the external environment, the requirements for portable fans and ducting, and potential impact to other requirements such as Fire Protection. Installation includes a dry-run to ensure functionality. This SAMA does not involve permanent plant modifications. This SAMA is similar to ones at a number of other plants.			

SAMA 17: ENHANCE PROCEDURES AND PROVIDE ADDITIONAL EQUIPMENT TO RESPOND TO LOSS OF EDG CONTROL ROOM VENTILATION			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$150,000	$0	$0
Material	$0	$50,000	$50,000
Installation	$0	$50,000	$50,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$0	$0	$0
Procedures and Training	$50,000	$0	$0
S1 Cost	$200,000		
S2 Cost	$200,000		
Summary:			
This SAMA involves opening the EDG control room doors to help establish a ventilation path. Part of the Engineering cost is to evaluate the feasibility of opening the doors since there are potential separation issues ($50K). The Engineering work includes the determination of the air flow paths from the respective rooms to the external environment, the requirements for portable fans and ducting, and potential impact to other requirements such as Fire Protection. Installation includes a dry-run to ensure functionality. This SAMA does not involve permanent plant modifications. This SAMA is similar to ones at a number of other plants.			

6.d SAMAs 21 and 22 are similar in that each involves installing fire barriers to prevent the propagation of a fire between cabinets. SAMA 21 modifies 48 cabinets at a cost of $3.23M while SAMA 22 modifies 3 consoles at a cost of $1.6M, which is only about half the cost of SAMA 21. Provide an explanation for this apparent discrepancy.

PSEG Response:

A table was prepared for each SAMA that included cost estimates and a summary of the SAMA changes. These tables are provided for SAMAs 21 and 22. The summaries describe the rationale for the differing costs. Although SAMA 21 involves more cabinets, it is significantly simpler due to the location and structure of the cabinets. SAMA 22 is more complicated because it involves the Control Room consoles. The differences in the cost estimates are justified. There is no discrepancy.

SAMA 21: ENHANCE FIRE BARRIERS FOR RELAY ROOM CABINETS			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$300,000	$0	$0
Material	$0	$2,200,000	$2,200,000
Installation	$0	$880,000	$880,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$0	$0	$0
Procedures and Training	$0	$0	$0
S1 Cost	$3,230,000		
S2 Cost	$3,230,000		
Summary:			
This SAMA involves improving the capability of cabinets in the Relay Room to contain a fire (i.e. fire barrier) and thus stop propagation of the fire to adjacent cabinets. There are approximately 68 cabinets in the Relay Room (each unit). The Cat I cabinets (~20 of 68) already have sufficient fire barrier capabilities. The Cat II cabinets (~8 of 68) and the Cat III cabinets (~40 of 68) do not have sufficient fire barrier capability to contain a fire and thus are addressed by this SAMA. The Cat II cabinets would require fire barrier materials along with ventilation modifications. The Cat III cabinets are actually open racks and would require the fabrication of custom cabinets with fire barrier materials and ventilation to enclose them. These custom cabinets would need to be installed around the existing racks with minimal disturbance. The cost per Cat II cabinet is estimated at $25K for Materials and $10K for Installation. The cost per Cat III cabinet is estimated at $50K for Materials and $20K for Installation. The Engineering costs include $50K for a feasibility study. This SAMA involves permanent plant modifications.			

SAMA 22: ENHANCE FIRE BARRIERS FOR CONTROL ROOM CONSOLES			
	SHARED S1/S2	S1 ONLY	S2 ONLY
Engineering	$800,000	$0	$0
Material	$0	$600,000	$600,000
Installation	$0	$600,000	$600,000
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$0	$0	$0
Procedures and Training	$0	$0	$0
S1 Cost	$1,600,000		
S2 Cost	$1,600,000		
Summary:			
This SAMA involves improving the capability of the three control consoles (CC1, CC2, CC3) in the Control Room to contain a fire (i.e. fire barrier) and thus stop propagation of the fire to adjacent consoles. These large consoles have tight internal clearances and many openings for instrumentation. In addition to adding fire barrier materials, the consoles have significant heat loads so ventilation modifications will be needed. The cost per console is estimated at $200K for Materials and $200K for Installation. The Engineering costs include $100K for a feasibility study. This SAMA involves permanent plant modifications.			

6.e SAMAs 10 and 11, which appear to only involve procedure modifications, are each estimated to have an implementation cost of $100K (per unit). Section E.5.1.1 states that the minimum expected implementation cost is assumed to be a procedure change at $50K to $100K for the site. Justify the implementation cost estimates of $100K for SAMAs 10 and 11, and confirm that the cost estimates are for a single unit.

PSEG Response:

A table was prepared for each SAMA that included cost estimates and a summary of the SAMA changes. These tables are provided for SAMAs 10 and 11. The summaries describe the rationale for the costs. SAMA 10 has a cost above the minimum $50K due to the need for a feasibility study and the impact on Emergency Operating Procedures (EOPs). EOPs are more expensive to revise and require more extensive training of the Operators. SAMA 11 has a cost above the minimum $50K due to the need for a feasibility study and the involvement of Licensing. The $100K cost estimates are for a single unit. The cost estimates are justified.

SAMA 10: PROVIDE PROCEDURAL GUIDANCE FOR FASTER COOLDOWN ON LOSS OF RCP SEAL COOLING			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$50,000	$0	$0
Material	$0	$0	$0
Installation	$0	$0	$0
Licensing	$0	$0	$0
Critical Path Impact	$0	$0	$0
Simulator Modification	$0	$0	$0
Procedures and Training	$150,000	$0	$0
S1 Cost	$100,000		
S2 Cost	$100,000		
Summary:			
The $50K for Engineering is a feasibility study to confirm that there is no technical basis preventing implementation of a more rapid cooldown under these conditions. The procedure revisions are extensive due to the number of places that the cooldown information appears and the fact that some of the revisions involve Emergency Operating Procedures (EOPs). This SAMA does not involve permanent plant modifications.			

SAMA 11: MODIFY PLANT PROCEDURES TO MAKE USE OF OTHER UNIT'S PDP			
	SHARED S1/S2	**S1 ONLY**	**S2 ONLY**
Engineering	$50,000	$0	$0
Material	$0	$0	$0
Installation	$0	$0	$0
Licensing	$0	$50,000	$50,000
Critical Path Impact	$0	$0	$0
Simulator Modification	$0	$0	$0
Procedures and Training	$50,000	$0	$0
S1 Cost	$100,000		
S2 Cost	$100,000		
Summary:			
The $50K for Engineering is a feasibility study to confirm that there is no technical basis preventing PDP cross-tie when RCP seal cooling is lost. This SAMA does not involve permanent plant modifications.			

6.f The benefit and net value calculations for SAMAs 1, 5, and 8 are not consistent with the methodology described. For example, the "SAMA 1 Non-Fire Averted Cost-Risk" on page E-117 includes the full external event multiplier of 2 as described in Section 4.6.3 (which includes fire CDF). A calculation for "fire averted cost-risk" is then added to the previous calculation (apparently double counting the fire risk). Furthermore, while the "SAMA 1 Net Value" table on page E-119 shows a cost of implementation of $475K, the "Net Value" calculated assumes an implementation cost of only $100K. Clarify these discrepancies and provide revised analyses if necessary.

PSEG Response:

The NRC has previously indicated a preference to not adjust the external events multiplier when quantifying the averted cost-risk for SAMAs that impact both internal and external events, even if the external events contribution is explicitly quantified. While it is recognized that this process results in "double-counting" some external events contributions to the total averted cost-risk that is calculated, this practice has been maintained unless it results in a gross misrepresentation of a SAMA's benefit. For SAMAs 1, 5, and 8, inclusion of the explicit external events contributions does not impact the conclusions of the analysis when the 95th percentile PRA results are considered. This remains true even if the corrected net electric output value documented in the response to RAI 6.k (1195 MWe) were to be used.

For those SAMAs that impact both internal and external events, it is generally considered important to explicitly quantify the impact of the SAMA on the external events risk it was intended to address to avoid the situation whereby the general external events multiplier underestimates the external events averted cost-risk.

For SAMA 1, the net value that is calculated in Section E.6.1.4 of the ER submittal is incorrect. The correct net value is $4,309,252 using the input documented in the ER, which is reflected in the sensitivity analyses located in sections E.7.1 and E.7.2 of the ER submittal.

6.g The tables on pages E-121, E-125, E-150, E-151, and E-190 for SAMAs 2, 4, 18, 19, and 5A (providing the change in CDF, PDR, and OECR by release category) are inconsistent with the SAMA quantification results and appear to be incorrect. Provide corrected tables, and any other corrections if necessary.

PSEG Response:

Corrected tables for the identified SAMAs are provided below. No re-quantification was necessary since the reported cost-risk values were correct. The tabular values noted as being inconsistent were determined to be typographical errors. The rows with the following labels have been changed in the release category tables below to remedy such errors: $Frequency_{SAMA}$, Dose-$Risk_{SAMA}$, and $OECR_{SAMA}$.

SAMA 2

	CDF	DOSE-RISK	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.45E-05	70.54	$276,691
Percent Change	10.0%	9.8%	9.5%

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$\text{Frequency}_{\text{BASE}}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$\text{Frequency}_{\text{SAMA}}$	9.20E-06	1.81E-10	9.89E-07	1.68E-08	2.98E-05	2.97E-08	1.98E-07	3.12E-08	2.55E-06	1.98E-07	1.57E-06	**4.45E-05**
$\text{Dose-Risk}_{\text{BASE}}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$\text{Dose-Risk}_{\text{SAMA}}$	0.15	0.00	0.02	0.04	37.21	0.62	2.06	0.34	23.18	0.78	6.14	**70.54**
$\text{OECR}_{\text{BASE}}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$\text{OECR}_{\text{SAMA}}$	$29	$0	$5	$194	$99,418	$2,393	$7,871	$1,139	$115,152	$6,385	$44,103	**$276,691**

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Salem Unit 1	$16,564,000	$14,963,210	$1,600,790

SAMA 4

	CDF	DOSE-RISK	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.18E-05	66.67	$263,240
Percent Change	15.5%	14.8%	13.9%

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.20E-06	1.81E-10	9.89E-07	1.57E-08	2.72E-05	2.97E-08	1.95E-07	3.13E-08	2.55E-06	1.98E-07	1.40E-06	**4.18E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.04	34.04	0.62	2.03	0.34	23.18	0.78	5.46	**66.67**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$182	$90,965	$2,393	$7,753	$1,144	$115,142	$6,385	$39,242	**$263,240**

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Salem Unit 1	$16,564,000	$14,179,592	$2,384,408

SAMA 18

	CDF	DOSE-RISK	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.91E-05	77.54	$303,246
Percent Change	0.9%	0.9%	0.8%

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.38E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	1.99E-06	**4.91E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	42.24	0.62	2.31	0.37	23.18	0.78	7.80	**77.54**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$292	$112,859	$2,393	$8,834	$1,240	$115,152	$6,385	$56,057	**$303,246**

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Salem Unit 1	$16,564,000	$16,424,896	$139,104

SAMA 19

	CDF	DOSE-RISK	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.90E-05	78.18	$305,519
Percent Change	1.0%	0.0%	0.1%

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	8.73E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.21E-07	3.35E-08	2.55E-06	1.98E-07	2.03E-06	**4.90E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.14	0.00	0.02	0.06	42.78	0.62	2.29	0.36	23.18	0.78	7.93	**78.18**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$28	$0	$5	$292	$114,308	$2,393	$8,755	$1,222	$115,152	$6,385	$56,978	**$305,519**

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Salem Unit 1	$16,564,000	$16,530,228	$33,772

SAMA 5A

	CDF	DOSE-RISK	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.48E-05	70.63	$276,851
Percent Change	9.5%	9.7%	9.4%

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	TOTAL
$\text{Frequency}_{\text{BASE}}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$\text{Frequency}_{\text{SAMA}}$	9.43E-06	1.81E-10	9.89E-07	2.52E-08	2.98E-05	2.97E-08	2.01E-07	3.15E-08	2.55E-06	1.98E-07	1.56E-06	**4.48E-05**
$\text{Dose-Risk}_{\text{BASE}}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$\text{Dose-Risk}_{\text{SAMA}}$	0.15	0.00	0.02	0.06	37.25	0.61	2.09	0.34	23.21	0.78	6.10	**70.63**
$\text{OECR}_{\text{BASE}}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$\text{OECR}_{\text{SAMA}}$	$30	$0	$5	$292	$99,532	$2,391	$7,980	$1,150	$115,260	$6,376	$43,836	**$276,851**

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
SGS Unit 1	$16,564,000	$14,987,254	$1,576,746

6.h The cost of implementation of SAMA 3, as shown in Table E.5-3, is \$525K. However, the SAMA analysis in Section E.6.3 uses an implementation cost of \$4.175M. Clarify which is correct and provide a revised analysis if necessary.

PSEG Response:

The implementation cost of \$4.175M used in Section E.6.3 is the correct value for SAMA 3. The \$525K figure listed in Table E.5-3 was identified as a typographical error. No revised analysis is necessary.

6.i For SAMA 5, the likelihood of offsite power nonrecovery was changed to 0.01 for grid and site/switchyard-related causes and to 0.03 for weather-related causes. Provide the baseline probabilities for these nonrecovery events.

PSEG Response:

The baseline probabilities are provided in the below Table:

POWER NON-RECOVERY EVENT	PROBABILITY
Grid non-recovery	0.24
Weather-related non-recovery	0.24
Plant/switchyard non-recovery	0.1

6.j Clarify the PRA model changes made for SAMA 17. Provide the initial and revised probability values used for failure of the EDG control room HVAC fans.

PSEG Response:

The fan basic event failure probabilities were changed as described by the following table:

PRA BASIC EVENT	ORIGINAL VALUE	SAMA VALUE
VDG-FNS-FS-VHE28	4.8E-03	4.8E-04
VDG-FNS-FS-VHE29	4.8E-03	4.8E-04
VDG-FNS-FS-VHE30	4.8E-03	2.3E-06

6.k Page 3-4 reports that the licensed thermal power for SNGS Unit 1 is 3,459 MWt, which equates to a net electrical output of 1,195 MWe when operating at 100 percent power. Page E-67 states that a power level of 1115 MWe was used to calculate long-term replacement power costs for the SAMA analysis, which is non-conservative with respect to the licensed power level. Clarify this discrepancy.

PSEG Response:

The 1,115 MWe power level identified on page E-67 and used in the calculation for replacement power to determine the Maximum Averted Cost-Risk (MACR) was incorrect. Using the correct value of 1,195 MWe increases the replacement power cost from $335,120 to approximately $359,170, an approximately 7% increase. The impact upon the MACR, however, is much less since the replacement power cost is a relatively small contributor to the MACR. Using the correct value of 1,195 MWe increases the MACR from $16,564,000 to $16,612,000, an increase of 0.3%. This small error in the MACR value is judged to have a negligible impact on the results and conclusions of the SAMA analysis.

7. PSEG's cost-benefit analysis showed that 12 of the SAMA candidates (SAMAs 1, 2, 4, 5A, 6, 9, 10, 11, 12, 14, 17, and 24) were potentially cost-beneficial in the baseline analysis and that an additional five SAMAs (SAMAs 3, 5, 7, 8, and 27) were potentially cost-beneficial based on the results of the sensitivity analysis. Address the following relative to these potentially cost-beneficial SAMAs:

7.a PSEG states on page E-194 that all 17 of these potentially cost-beneficial SAMAs will be considered for implementation using the existing Salem action-tracking and design change processes. Page 4-46 states that these potentially cost-beneficial SAMAs will be considered for implementation through the established Salem Plant Health Committee processes. Describe these two processes and how they are used to evaluate potentially cost-beneficial SAMAs.

PSEG Response:

The following processes are used in the review of potentially cost-beneficial SAMAs.

- Plant Health Committee Process – Used to structure the review of the potentially cost-beneficial SAMAs.
- Issue Identification and Screening Process – Used for action tracking of procedure revision requests, design change requests, and engineering work requests.
- Processing of Procedures – Used for implementing procedure revisions.
- Configuration Control Process – Used for implementing design changes.

Each of the potentially cost-beneficial SAMAs will be presented to the Plant Health Committee (PHC). This committee is chaired by the Plant Manager. Members include the Plant Engineering Manager, Director – Operations, Director – Engineering, Director – Maintenance, and Director – Work Management. The PHC is chartered to review issues that require special plant management attention to ensure effective resolution. With respect to potentially cost-beneficial SAMAs, the committee will decide on one of the following six actions for each SAMA.

<u>Approved for Implementation</u>:

i. The SAMA consists entirely of a procedure revision for which the technical basis exists. A procedure revision request will be initiated to implement the SAMA via the normal procedure revision process.

ii. The SAMA consists of a design change with well-defined cost. A design change request will be initiated to implement the SAMA via the normal design change process.

Conditionally Approved for Implementation:

iii. The SAMA consists entirely of a procedure revision for which the technical basis does not yet exist. An engineering work request will be initiated to develop the technical basis. The technical basis will be evaluated by PHC to decide whether to continue with implementation. It is possible that the technical basis can not be developed as described in the SAMA. In this case, the SAMA may not be cost-beneficial and thus will not be implemented. If implementation will continue, a procedure revision request will be initiated to implement the SAMA via the normal procedure revision process.

iv. The SAMA consists of a design change that does not have a well-defined cost but the cost is low. A design change request will be initiated to implement the SAMA via the normal design change process but there will be an evaluation by PHC at the 30% completion milestone to decide whether to continue with implementation. At the 30% completion milestone, the detailed design is basically complete. It is possible that the detailed design will show the SAMA is not cost-beneficial and thus will not be implemented.

v. The SAMA consists of a design change that does not have a well-defined cost and the cost is high. An engineering work request will be initiated to perform a conceptual design. PHC will review the completed conceptual design and decide whether to continue with implementation. It is possible that the conceptual design will show the SAMA is not cost-beneficial and thus will not be implemented. If implementation will continue, a design change request will be initiated to implement the SAMA via the normal design change process.

Disapproved:

vi. The SAMA will not be implemented.

It is possible that a SAMA could be tabled by the PHC awaiting additional information. The information request would likely fall into one of the following categories.

- PHC identified a correction that needs to be made in the SAMA analysis. The impact of this correction needs to be determined.
- PHC identified an alternate solution that will meet the SAMA goal at a lower cost. This alternate solution needs to be examined.
- PHC requests a PRA sensitivity study to determine the effect of implementing a specified SAMA subset on this SAMA.
- PHC requests a PRA sensitivity study to determine the effect of already approved SAMAs on this SAMA.

- PHC requests a PRA sensitivity study to determine the effect of already approved non-SAMA design changes on this SAMA.

- PHC requests coordination of this SAMA with related Mitigating System Performance Index (MSPI) margin recovery activities. The details of this coordination need to be presented to PHC.

A tabled SAMA will be re-presented to the PHC when the requested information has been assembled. At the completion of the PHC review, there will be no tabled SAMAs.

The SAMAs that are "Approved for Implementation" or "Conditionally Approved for Implementation" will be ranked with respect to priority and assigned target years for implementation. They will be scheduled consistent with this priority structure and in accordance with the normal budgetary and work management processes. The implementation schedule may include "hold points" for PRA model updates and determination of the effect on the remaining SAMAs.

Each PHC decision and its rationale will be documented in the minutes of the associated PHC Meeting.

7.b In view of the significant number of potentially cost-beneficial SAMAs, it is likely that several of these SAMAs address the same risk contributors. As such, implementation of an optimal subset of these SAMAs could achieve a large portion of the total risk reduction at a fraction of the cost, and render the remaining SAMAs no longer cost-beneficial. In this regard: identify those SAMAs that PSEG considers highest priority for implementation, provide a revised cost-benefit analysis assuming these high priority SAMAs are implemented, and identify those SAMAs that would no longer be cost-beneficial given implementation of the high-priority SAMAs. Also, provide any specific plans/commitments regarding implementation of the high priority SAMAs.

PSEG Response:

PRA sensitivity studies to find the optimal subset of potentially cost-beneficial SAMAs were not performed due to the large number of possible combinations. One of the purposes of the review of the potentially cost-beneficial SAMAs by the Plant Health Committee (PHC) is to identify potential synergies between SAMAs using the wide breadth of plant knowledge available on the PHC. The PHC can request targeted sensitivity studies to better understand these synergies.

The SAMAs that are "Approved for Implementation" or "Conditionally Approved for Implementation" will be ranked with respect to priority and assigned target years for implementation. They will be scheduled in a consistent manner with this priority structure and in accordance with the normal budgetary and work management processes. The implementation schedule may include "hold points" for PRA model updates and determination of the effect on the remaining SAMAs.

As an example of a hold point, the SAMA analysis was re-evaluated in February 2010 using the then-current revision of the Salem PRA Model, which included the incorporation of selected plant changes made after the SAMA analysis described in the LRA (based on PRA MOR Rev. 4.1) was performed. The PRA model evolves with the plant, and thus the impact of an updated PRA model on the SAMA anazysis has been evaluated.