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SUSQUEHANNA STEAM ELECTRIC STATION
APPLICATION FOR RENEWED OPERATING LICENSES
NUMBERS NPF-14 AND NPF-22
RESPONSE TO SAMA RAI's **Docket Nos. 50-387**
PLA-6154 **and 50-388**

References: 1) *PLA-6110, Mr. B. T. McKinney (PPL) to Document Control Desk (USNRC), "Application for Renewed Operating Licenses Numbers NPF-14 and NPF-22," dated September 13, 2006.*

2) *Letter from USNRC to Mr. B. T. McKinney (PPL), "Request for Additional Information Regarding Severe Accident Mitigation Alternatives for Susquehanna Steam Electric Station, Units 1 and 2 (TAC NOS. MD3021 and MD3022)," dated January 16, 2007.*

In accordance with the requirements of 10 CFR 50, 51, and 54, PPL requested the renewal of the operating licenses for the Susquehanna Steam Electric Station (SSES) Units 1 and 2 in Reference 1.

The purpose of this letter is to provide responses to the Request for Additional Information (RAI) transmitted to PPL Susquehanna LLC, (PPL) in Reference 2.

The enclosure provides PPL's responses. Please note that during preparation of these responses, a minor error in the SAMA evaluation for assumed MWth in pre-EPU conditions was discovered. As a result, the pre-EPU dose rates were under-represented in the analysis. This error was determined to be insignificant and there is no effect on the post-EPU dose rates in the submittal. Further discussion of this issue is provided in PPL's response to Question 4a.

There are no new regulatory commitments contained herein as a result of these responses.

A120

If you have any questions, please contact Mr. Duane L Filchner at (610) 774-7819

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

Executed on: 4-12-07

B. T. McKinney

Enclosure: PPL Responses to Request for Additional Information (RAI)

Copy: NRC Region I
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Alicia Mullins, NRC Project Manager, License Renewal, Environmental
Mr. A. J. Blamey, NRC Sr. Resident Inspector
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Enclosure to PLA-6154
PPL Responses to
Request for Additional Information (RAI)

Supplemental Information

NRC Question 1:

Provide the following information regarding the Susquehanna Steam Electric Station (SSES) Probabilistic Risk Assessment (PRA) model used for the Severe Accident Mitigation Alternative (SAMA) analysis:

NRC Question 1a:

Provide a summary of the major Level 1 and 2 PRA versions and their Core Damage Frequency (CDFs) from the Individual Plant Examination (IPE) to the present, including the version reviewed by the Boiling Water Reactor Owners Group (BWROG), and the version used for risk-informed submittals such as inservice inspection and allowed outage time extension for offsite power. Also, indicate the major changes to each version from the prior version (including the changes from pre-Extended Power Uprate (EPU) to post-EPU models) and the major reasons for changes in the CDF.

PPL Response:

A listing of PPL risk models, associated CDF and major changes is in Table 1a:

Table 1a

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
IPE	Original Model. NRC SER dated 8/11/1998.	5.6×10^{-7}/year	Excess Flow Check Valve Surveillance frequency extension (NRC License Amendments 193 (U1) and 168 (U2)	Initial Model – no change.
Modified IPE (July, 2001 to January, 2002)	Included enhancements as a result of the IPE. The most significant enhancement was the addition of the Station Portable Diesel Generator (Blue Max) backup diesel generator.	3.7×10^{-7}/year	One Time ILRT Test Deferral (NRC Licensing Amendments 202 (U1) and 176 (U2)).	CDF decrease due to addition of Blue Max, which supplies power to the 125 VDC battery chargers.
Modified IPE (January, 2002 to August, 2002)	Corrected treatment of off-site power recovery. Manual Rod Insertion on LOOP not credited. Manual HPCI suction transfer credit deleted.	5.3×10^{-7}/year	Removal of HPCI Auto Suction Swap (NRC License Amendments 204 (U1) and 178 (U2)).	CDF increases as a result of removal of non-credible LOOP recoveries and the assumption that Manual Rod Insertion (MRI) cannot be credited during LOOP. The HPCI change eliminated a vulnerability in the IPE, which was an ATWS combined with a failure of SLC.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
Revised IPE (October, 2002)	Model converted to CAFTA. All containment failures or venting assumed to result in core damage. Two CRD pumps eliminated for high-pressure make-up success. Late injection following containment failure not credited (SSES does not have a 'hard pipe' containment vent). Eliminated RWCU blowdown as a heat removal method.	2.3×10^{-5}/year	Start-up transformer T-20 NOED (NOED No. 2002-01-03). T-20 is one of the two off-site AC power sources for SSES.	Major increase in CDF is due to the change that assumes containment failure will result in core damage.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
012903 (January, 2003)	'E' EDG credited as backup for the Blue Max which supplies power to the 125 VDC battery chargers. Ran selected BWRSAR cases and made limited changes to Event Trees. Core damage success criteria revised to be <1800°F PCT. Addition of LOOP initiating event fault tree. Credit taken for late injection following containment failure or venting if sources and systems credited were outside the reactor building. Model based on rated power of 3489 MWt. Added Direct Containment Heating (DCH) path for high-pressure RPV failure.	2.5×10^{-6}/year	Start-up transformer T-10 Technical Specification. one time AOT extension (NRC License Amendments 214 (Unit1) and 189 (Unit 2). T-10 is one of the two off-site power supplies for SSES.	Addition of late injection is the most significant contributor to CDF reduction.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
SSESCertR20 (October, 2003)	Updated Event Trees to be consistent with current EOP's. Updated success criteria. Added Event Trees for Inadvertent Opening of a Relief Valve (IORV) and Interfacing System LOCA (ISLOCA). Sequences extended if containment failed prior to the occurrence of core damage. Six ADS S/RV's required for medium LOCA depressurization success. Added catastrophic RPV failure causing core damage.	3.2×10^{-6}/year	No submittals were performed using this model. Model was developed for review by the Peer Review Team in Oct. 2003.	Addition of the ISLOCA initiating event was the most significant contributor to increase in CDF.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
FEB05 (February, 2005)	Model updated in response to impacting Peer Review B-level F&Os (No A-level F&Os received). Flooding initiators added. A single model including both units created. Reduction in direct containment heating probability. Deleted operator recoveries in the reactor building following core damage.	Unit 1 = 3.0×10^{-6}/year Unit 2 = 2.8×10^{-6}/year	Submittal of ISI program (PLA-5662, PLA-5768, PLA-5804, PLA-5826 and NRC letter dated July 28, 2005 to B. T. McKinney.	Model revisions resulting from B-level F&O responses reduced CDF. Model changes included DCH probability reduction and the addition of recoveries to the model. The CDF numbers for the two units are different because of the difference in the method for emergency switchgear cooling and the alignment of station batteries between the units.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
FEB06PreEPU, FEB06EPU	A single two-unit model created for pre-EPU conditions and a separate complete two-unit model created for EPU conditions. Complete Event Tree revision with success criteria based on MAAP4 calculations. Added complete Level 2 model (twelve specific release categories). Revised LOOP probability to use NUREG/CR-INEEL/EXT-0402326. Use of industry standard core damage criteria for ATWS stability events. Modified Large and Medium LOCA success criteria to one loop of CS and one division of ADS (3 valves). Developed corresponding risk model for EPU conditions.	Unit1 = 1.9×10^{-6}/year (Pre-EPU); 2.0×10^{-6}/year (EPU). Unit 2 = 1.8×10^{-6}/year (Pre-EPU); 1.9×10^{-6}/year (EPU).	Application for Extended Power Uprate (PLA-6002) – Application withdrawn in May, 2006. Application for License Renewal. (PLA-6110)	CDF reduction results from: (1) Core damage in ATWS revised so that not all ATWS instability events result in core damage (revised so that ATWS core damage definition is consistent with industry standard); and (2) Success criteria for large and medium LOCA's revised such that one loop of core spray or one RHR pump in LPCI mode is credited for success. The success criteria was revised to be consistent with NEDO-24708A and supported by PPL calculations documented in EC-RISK-1135 and EC-RISK-1136.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
AUG06 PreEPU-c, AUG06EPU	Deleted ATWS sequences on success branches with operator actions that are evaluated to have no chance of success. Added credit for RHRSW injection in delayed low RPV pressure cases that had previously been excluded. Revised number of SRVs required to prevent RPV overpressure failure in ATWS from 13 to 12. Revised mission time of SLC pumps from 24 hours to 1 hour. The AUG06EPU model incorporated the SLCS modification for EPU, which includes single SLCS pump operation and the use of enriched Boron-10 in the SLCS solution.	Unit1 = 1.6×10^{-6}/year (Pre-EPU); 1.7×10^{-6}/year (EPU). Unit 2 = 1.6×10^{-6}/year (Pre-EPU); 1.7×10^{-6}/year (EPU).	Revised Application for Extended Power Uprate (PLA-6076, PLA-6128, PLA-6138, PLA-6146, PLA-6155 and PLA-6163).	The majority of the CDF reduction is due to the incorporation of proper credit for RHRSW injection in delayed low RPV pressure cases. Reduction of the SLC pump mission time and the reduction in number of SRVs required for success also contributed to the overall decrease in CDF.

Model	Major Model Changes	Base CDF	Submittals that Used Model	Reason for Change in CDF
AUG06 PreEPU-d, AUG06EPU	Added one pump SLCS operation with enriched Boron-10 to the AUG06Pre-EPU-d model. The AUG06EPU model does not change.	Unit1 = 1.6×10^{-6}/year (Pre-EPU). Unit 2 = 1.6×10^{-6}/year (Pre-EPU). No EPU change because the EPU model does not change.	No submittals were completed using this model. This model was created to support operation at pre-EPU conditions with enriched Boron in the SLC system and to correct some other minor modeling errors.	Eduction from two SLC pump operation to a single SLC pump required results in a very small change in calculated CDF (1.6466×10^{-6}/year from 1.6471×10^{-6}/year for Unit 1 and 1.6291×10^{-6}/year from 1.6296×10^{-6}/year for Unit 2).

NRC Question 1b:

Provide the freeze date for the incorporation of design and/or procedure changes into the PRA.

PPL Response:

The plant design changes and procedure changes are routinely reviewed for PRA impact as they occur. The freeze date for the FEB06preEPU and FEB06EPU models is January 19, 2006. The models were used in the License Renewal Application.

NRC Question 1c:

Provide the CDF contribution due to Station Blackout (SBO) and Anticipated Transient Without Scram (ATWS).

PPL Response:

The SBO and ATWS contributions to CDF are listed below:

Condition	Contribution to CDF	
	Unit 1	Unit 2
SBO	17.1%	12.8%
ATWS	5.1%	5.2%

The difference in contribution to CDF between Unit 1 and Unit 2 for the SBO event is due to battery failures on Unit 1. The diesels need 125VDC to start and this power normally comes from the Unit 1 batteries for diesel generators A – D (the E DG has a dedicated battery in the E DG building). There is a manual transfer to the Unit 2 battery however; this transfer is not modeled since the transfer activity can take 30 minutes.

NRC Question 1d:

Explain why loss of an AC bus is a very small (approximately 0.2 percent) contributor to the CDF.

PPL Response:

The loss of an AC bus as an initiator makes a small contribution to CDF at SSES because there are four safety related, 4160 VAC buses per unit and the loss of any bus by itself does not cause an immediate plant trip. The loss of any of the four AC buses will however, if not quickly recovered, result in an entry into the Technical Specification Actions. If the bus is not recovered within 8 hours, a manual shutdown is required by the Technical Specifications within the next 12 hours. In the PRA model, the loss of an AC bus is therefore assumed to lead to a manual shutdown which precludes an ATWS condition. Therefore, due in part to the AC bus redundancy and in part to the controlled shutdown given the loss of a single AC bus, the loss of an AC bus is not a significant contributor to CDF.

NRC Question 1e:

The summary of the BWROG peer review overall assessment provided on pages E.2-14 and -15 describes a non-conservatism associated with SBO events. Identify the Facts and Observations (F&Os) associated with this non-conservatism and discuss their resolution.

PPL Response:

The resolution of the F&Os is included in the disposition portion for all "B" F&O items included in Section E.2.3.3.1 of the license renewal application. The F&Os most directly related to potential non-conservatisms associated with SBO events are listed below.

- 250V DC Load Shed (Index 2 and Index 59)
- Control of HPCI/RCIC (Index 3 and Index 58)

NRC Question 1f:

Section E 2.3.2 of the Environmental Report (ER) describes a self assessment that considered the open Level B F&Os and concluded that the remaining items and gaps would not have a significant impact on the EPU application. Confirm that the same conclusion can be drawn concerning the impacts of the remaining items and gaps on the SAMA analysis.

PPL Response:

The self-assessment and review of the remaining open "B" F&O's was performed in advance of the EPU and SAMA efforts. The detailed resolution of the "B" findings provided in Section E.2.3.2.1 specifically reference EPU/SAMA impact, not just EPU impact. The paragraph above Section E.2.3.2 should have stated that the self-assessment was performed in support of EPU and SAMA, not just EPU.

NRC Question 1g:

Describe the current containment venting capability and procedural directions at SSES (hard pipe, via standby gas treatment system, etc.) and how it is modeled in the PRA.

PPL Response:

Containment Venting Capability

SSES does not have a hard-pipe vent. SSES is able to vent primary containment through secondary containment using the pipe/duct going to the Standby Gas Treatment System (SGTS). However, this path does not have the capacity to successfully vent primary containment without breaching when containment is at or near venting pressure. Therefore, it is expected (and modeled) that primary containment venting near the primary containment venting pressure will fail the vent path and cause a severe environment in secondary containment. As such, it is anticipated that the active electrical devices including the controls for HPCI and RCIC will be rendered non-functional due to the steam environment. The venting procedure provides instructions to align systems in the reactor building before the containment venting or containment failure.

Procedural Direction

Venting of the primary containment or the RPV is only performed, by procedure "upon acceptable evaluation of offsite consequences." That is, the decision to vent must not be made unconditionally based on plant parameters but instead, with an awareness of the impact such action will have on public health and safety. To begin an evaluation of the venting decision, primary containment source term radiation levels must first be

determined. Guidance for venting is then dependent upon expected offsite and/or Control Room dose/dose rate projections as defined in terms of containment radiation levels. Three ranges are considered:

1) No Source Term
2) Small Source Term
3) Large Source Term

Criteria defining each range are provided in the applicable decision block basis discussion in the procedure.

As plant parameters change, the elected venting strategy must be continuously re-assessed. Modification to the chosen strategy must be pursued as the changing condition warrants. Additionally, plant systems supporting accident mitigation in the affected Reactor Building must be appropriately aligned prior to discharging primary containment atmosphere to secondary containment.

Venting With No Source Term

With no source term present, venting is permitted by procedure. The radiological release which occurs as a result of the venting process is expected to remain below Technical Requirements Manual TRO limits. No offsite consequences are anticipated due to the absence of source term radiation.

Venting With a Small Source Term

With primary containment radiation levels within the range defining a small source term, venting is permitted with caution. The radiological release which occurs as a result of the venting process is expected to remain below General Emergency Declaration Criteria and 10 CFR 50 Appendix A limits. Containment pressure or combustible gas may threaten continued core cooling or the containment function. Venting avoids over-pressure failure of the containment structure, removes combustible gas from the containment air space, permits continued SRV operation (thus preserving core cooling via low pressure injection systems), and allows core submergence through the flooding process. Because the source term is not large, venting is allowed after due consideration of the in-plant and offsite dose consequences. A "no vent" strategy may be adopted if challenges to the RPV and primary containment are deemed manageable and venting is determined to be unacceptably detrimental to the overall accident mitigation effort.

Venting With a Large Source Term

With a large source term in primary containment venting is not recommended by procedure. The radiological release which occurs as a result of the venting process is expected to exceed General Emergency Declaration Criteria or 10 CFR 50 Appendix A limits. Although containment pressure or combustible gas may threaten continued core cooling or the containment function, the release of a large source term will create high plant and Control Room dose rates and is likely to result in loss of accident mitigation control due to necessary evacuation of the Control Room and the TSC. Large offsite dose rates are similarly expected.

It is important to note that venting is not prohibited by this step. Data such as plant equipment recovery prognosis, source term dynamics, the weather, and status of evacuation efforts must all be evaluated before the appropriate decision can be reached. In addition, venting may be directed from outside the Control Room via the SSES Emergency Plan.

PRA Fault Tree Modeling

The PRA model assumes that core damage produces a source term that is considered large under the procedural guidance. Hence in the PRA model, venting is not credited for large source terms (that is, the PRA model assumes that with a large source term in containment, containment fails on over-pressure (COPF)). For the cases which credit venting prior to the onset of core damage, the PRA model assumes all of ECCS is lost due to the steam environment after venting occurs. The model assumes that long term injection from a source external to the Reactor Building (RHRSW, condensate or fire protection water) is aligned before venting is initiated.

NRC Question 2:

Provide the following information relative to the Level 2 analysis:

NRC Question 2a:

Provide a summary description of the current Level 2 model, including: the Level 1/Level 2 interface, the Containment Event Tree (CET), the basis of quantification of CET nodes, the binning process used to assign end states to release categories, and the determination of release fractions for each release category.

PPL Response:

Level 1/Level 2 Interface

The SSES PRA model consists of a fully integrated set of Level 1 and Level 2 event trees. There is only one PRA model. There is not a Level 1 model and a subsequent Level 2 model. With this structure, all system dependencies, operator action dependencies, and other relationships are explicitly treated.

Containment Event Trees

There are approximately 25 event trees that model the full spectrum of initiating events from sequence initiation to containment response and ultimate Level 2 release characterization. As such, the end state of core damage could be located in the middle of the event tree with the subsequent nodes required for proper release characterization included within the same event tree. Figure 2a-1 provides an example event tree used in the SSES PRA model.

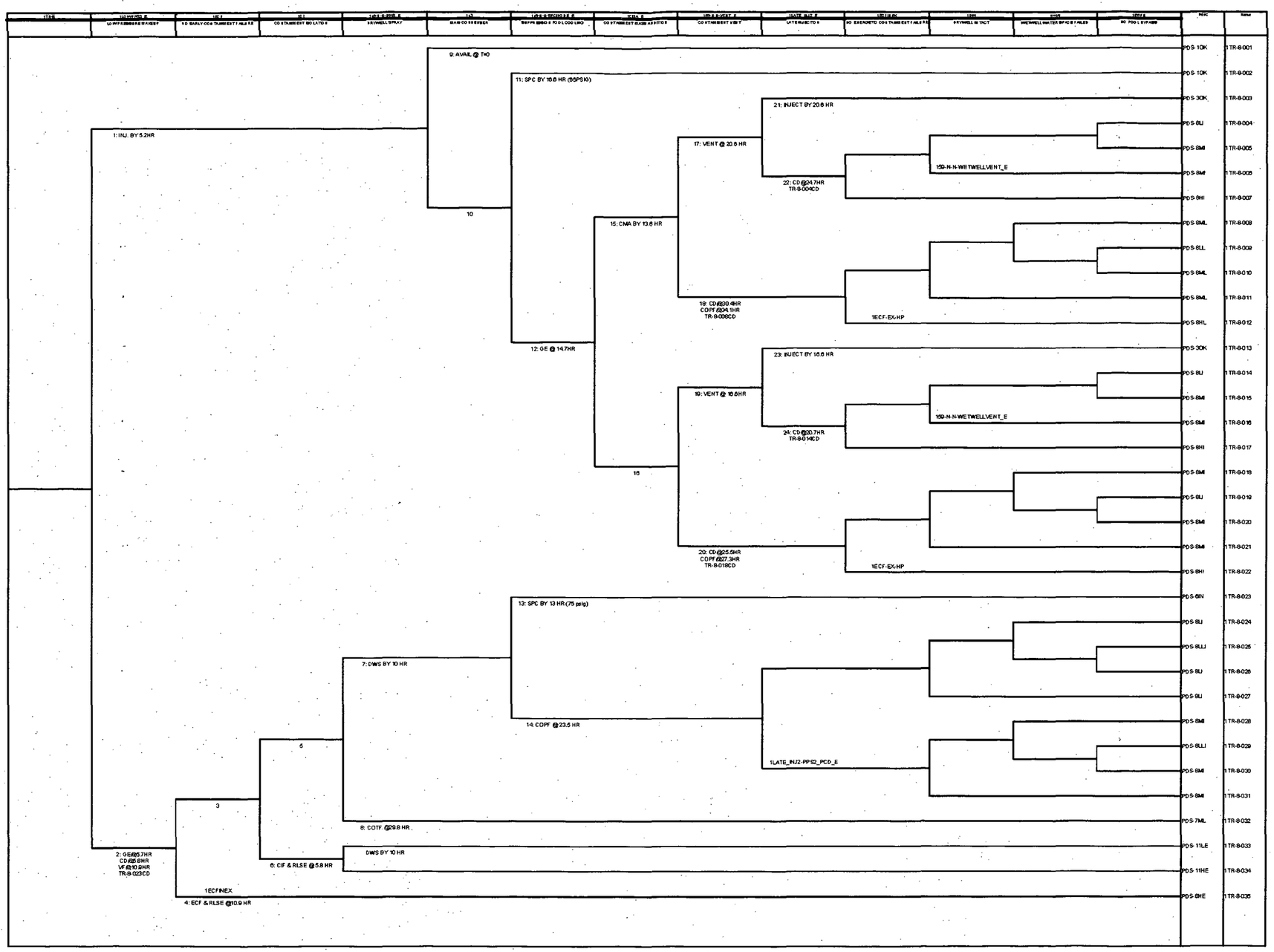

Figure 2a-1
EVENT TREE FOR DELAYED, LOW-EVENT PRESSURE CORE, VESSEL AND CONTAINMENT CHALLENGE (TR-8)

Figure 2a-1 shows an example of a typical SSES Event Tree. The entry condition to the TR-8 event tree shown in Figure 2a-1 are those sequences where initial high pressure injection was available (out to ~ 4 hours), extended high pressure injection was unavailable, but operators have successfully depressurized the RPV. Core damage sequences are defined for branches 2, 18, 20, 22, and 24. Specific indication of the time of General Emergency (GE) declaration, time of containment failure or vent, and time of core damage and vessel failure (if applicable) are provided along each branch of the Event Tree. Every numbered branch of the event tree includes detailed discussions within the event tree notebook to define appropriate conditions for each branch. This includes a specific subsection for each branch to discuss equipment requirements, operator actions, timing, and emergency plan impacts. References to appropriate thermal hydraulic calculations, system requirements, plant procedures, and emergency plan sections are also provided. Although not explicitly considered as unique to the "Level 2" analysis, the success or failure of the drywell sprays, containment mass addition, containment vent, and late injection will have an impact on the final release characterization. This structure allows for a full understanding of the conditions present such that a minimal set of additional nodes are required for the determination of the fission product release characteristics.

Figure 2a-1 shows that additional nodes are considered, after each of these core damage sequences, to establish the appropriate release characterization. These nodes include both phenomenological impacts as well as system availability requirements. Given vessel failure is predicted to occur, additional nodes are included for early/energetic containment failure, and for containment isolation failures. Given containment failure or vent occurs, additional nodes are included to establish availability of late injection (if not already asked in the core damage determination), and to establish the containment breach location (drywell region, wetwell airspace, or wetwell below the water line), and if the breach location is in the wetwell airspace, whether or not the suppression pool is bypassed. If the suppression pool is not bypassed, containment breach in the wetwell airspace allows for Iodine scrubbing in the radioactivity release; however, no Iodine scrubbing is modeled if the suppression pool is bypassed.

With this integrated structure, a unique General Emergency declaration time and fission product release time is available to clearly establish the timing of the release based on the categories shown in Table E.2-1 of the license renewal application. Additional references to MAAP case results are then used to establish the magnitude of the release as also indicated in Table E.2-1. Integrating the severity and timing categories yields 12 separate release category end states using a two-term matrix (severity, timing) as shown in Table E.2-2 of the license renewal application.

A similar process to that described above for the TR-8 event tree example of identifying additional requirements for appropriate fission product release characterization is then followed for all of the event trees. Table E.2-3 from the license renewal application

provides a summary of the release fractions for each release category from the various PRA models (i.e. unit and EPU or pre-EPU specific). A representative MAAP case for development of source terms for each of the release categories was then chosen. The principal reason for the basis of the representative case selection was that the timing and magnitude of the release agreed with the release category characterization. Therefore, the exact sequence of events did not always agree with the dominant contributors from the analysis, but given the release characteristics matched, other differences were judged to have only second order impacts on the results. The representative MAAP cases are summarized in Tables E.2-4a and E.2-4b of the license renewal application. A more detailed discussion of the representative MAAP cases and the basis for their selection is provided below in Table 2a-1 for the pre-EPU conditions and in Table 2a-2 for EPU conditions.

Table 2a-1 Summary of Representative Source Term Cases (pre-EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
H/E	SU0516	ATWS, No RPV depressurization, Early Large DW failure	5.9E-1 from 3.8 to 5 hrs	Large release early in time consistent with dominant LERF contributors (ISLOCA, LOCAs with vapor suppression failures).
H/I	SU0500	Transient with failure of high pressure injection and no RPV depressurization. No injection or containment spray. Large drywell failure on containment overpressure.	2.4E-1 from 21.4 to 48 hrs	Dominant contributors included delayed high pressure boil-off cases (TR-7-10B, 84%), and early high pressure boil-off cases (TR-2-23B, 16%). The early high pressure boil-off scenario was chosen as the representative case.

Table 2a-1 Summary of Representative Source Term Cases (pre-EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
H/L	SU0514	LOCA with loss of containment heat removal. Core damage very near the time of containment failure. No injection after containment failure.	3.4E-1 from 30 to 40 hrs	Dominant contributors included low RPV pressure loss of containment heat removal sequences (TR-8-12, 93%), and LOCA loss of containment heat removal sequences (LT-3-35, 7%). Timing and release characteristics for both contributors to this non-dominant release category are similar to the representative MAAP case.
M/E	SU0515	ATWS, RPV depressurization successful, early large drywell failure occurs.	6.0E-2 from 2 to 16 hrs	In the final base case analysis, there were no contributing sequences to this release category. Representative case chosen to provide appropriate release characteristics.
M/I	SU0500a	Transient with failure of high pressure injection and no RPV depressurization. No early injection or containment spray. Injection re-established just prior to the time of drywell failure on containment overpressure.	3.8E-2 from 21 to 48 hrs	Dominant contributor (TR-7-10A, 98%) sequence consistent with representative MAAP case description.

Table 2a-1 Summary of Representative Source Term Cases (pre-EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
M/L	SU0505	Transient with failure of all injection, but with RPV depressurization successful. No containment spray, large late drywell failure occurs on containment overpressure.	2.5E-2 from 33.5 to 48 hrs	Dominant contributors include similar low pressure scenarios with loss of injection. Some of the sequences had containment mass addition available up to containment overpressure failure (TR-8-32, 84% and TR-8-11, 6%) and some cases did not have containment mass addition prior to containment failure (TR-3-72, 5% and LT-3-57, 5%). Representative MAAP case chosen without containment mass addition.
L/E	SU0515a	ATWS, RPV depressurization successful, early large wetwell airspace failure occurs.	1.0E-3 from 2 to 4 hrs	Dominant contributors are all low pressure ATWS scenarios consistent with the representative MAAP case description.
L/I	SU0511	Loss of containment heat removal scenario with core damage near the time of containment failure (assumed to be in the wetwell airspace region).	2.0E-3 from 30.7 to 34 hrs	Dominant contributors are loss of containment heat removal sequences with injection available after core damage (TR-1-04a, 29%) or with injection lost after successful wetwell venting (TR-1-05, 71%). Representative MAAP case consistent with the dominant TR-1-05 scenario.

Table 2a-1 Summary of Representative Source Term Cases (pre-EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
L/L	SU0550	Medium LOCA with no injection or containment heat removal. Large late drywell failure occurs on containment overpressure.	7.0E-3 from 34 to 48 hrs	Release category includes various contributors all with early core damage followed by late containment failure. Timing and release characteristics are similar to the representative MAAP case.
LL/E	SU0516a	ATWS with early wetwell airspace failure.	7.8E-4 from 1 to 4 hrs	In the final base case analysis, there were no contributing sequences to this release category. Representative case chosen to provide appropriate release characteristics.
LL/L	SU0556a	Large LOCA with no injection or containment heat removal available. Late containment failure in drywell head region. External sprays successful, but only for containment mass addition, not heat removal.	4.0E-6 from 27.7 to 48 hrs	Dominant contributors are LOCA scenarios with no injection or heat removal, but with containment spray from an external source successful (LT-3-046, 90%, LT-3-042, 3%) or similar transient scenarios (TR-2-017, 7%). Timing and release characteristics are similar to the representative MAAP case.

Table 2a-2 Summary of Representative Source Term Cases (EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
H/E	ESU0516	ATWS, No RPV depressurization, Early Large DW failure	5.8E-1 from 3.4 to 48 hrs	Large release early in time consistent with dominant LERF contributors (ISLOCA, LOCAs with vapor suppression failures).
H/I	ESU0500	Transient with failure of high pressure injection and no RPV depressurization. No injection or containment spray. Large drywell failure on containment overpressure.	3.6E-1 from 17.3 to 48 hrs	Dominant contributors included delayed high pressure boil-off cases (TR-7-10B, 83%), and early high pressure boil-off cases (TR-2-23B, 17%). The early high pressure boil-off scenario was chosen as the representative case.
H/L	ESU0514	LOCA with loss of containment heat removal. Core damage very near the time of containment failure. No injection after containment failure.	4.8E-1 from 23.8 to 48 hrs	Dominant contributors included low RPV pressure loss of containment heat removal sequences (TR-8-12, 85%), and LOCA loss of containment heat removal sequences (LT-3-35, 15%). Timing and release characteristics for this non-dominant release category are similar to the representative MAAP case.

Table 2a-2 Summary of Representative Source Term Cases (EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
M/E	ESU0515	ATWS, RPV depressurization successful, early large drywell failure occurs.	5.6E-2 from 1.3 to 48 hrs	In the final base case analysis, there were no contributing sequences to this release category. Representative case chosen to provide appropriate release characteristics.
M/I	ESU0500a	Transient with failure of high pressure injection and no RPV depressurization. No early injection or containment spray. Injection re-established just prior to the time of drywell failure on containment overpressure.	6.1E-2 from 17.3 to 48 hrs	Dominant contributor (TR-7-10A, 98%) sequence consistent with representative MAAP case description.
M/L	ESU0505	Transient with failure of all injection, but with RPV depressurization successful. No containment spray, large late drywell failure occurs on containment overpressure.	2.9E-2 from 32.5 to 48 hrs	Dominant contributors include similar low pressure scenarios with loss of injection. Some of the sequences had containment mass addition available up to containment overpressure failure (TR-8-32, 85% and TR-8-11, 6%) and some cases did not have containment mass addition prior to containment failure (TR-3-72, 4.5% and LT-3-57, 4.5%). Representative MAAP case chosen without containment mass addition.

Table 2a-2 Summary of Representative Source Term Cases (EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
L/E	ESU0515a	ATWS, RPV depressurization successful, early large wetwell airspace failure occurs.	1.0E-3 from 1.3 to 48 hrs	Dominant contributors are all low pressure ATWS scenarios consistent with the representative MAAP case description.
L/I	ESE0131	MSIV closure, RCIC for HP makeup, RCIC fails @ 4 hr, ADS w/ 3 SRVs, 1 CS pump for LP makeup until Containment Vent @ 80 psia.	3.8E-3 from 21.1 to 31.1 hrs	Dominant contributors are loss of containment heat removal sequences with injection available after core damage (TR-1-04a, 25%) or with injection lost after successful wetwell venting (TR-1-05, 65%) and for EPU conditions, early core damage scenarios with injection available after containment failure (TR-2-021). Representative MAAP case consistent with TR-1-05 scenario. Timing and release characteristics for other contributors are similar to the representative MAAP case.
L/L	ESE0117	MSIV closure, RCIC for HP makeup until late containment failure, no SPC, ADS w/3 SRVs, no LP makeup	7.4E-3 from 40 to 58.6 hrs	Release category includes various contributors all with early core damage followed by late containment failure. Timing and release characteristics for this non-dominant contributor are similar to the representative MAAP case.

Table 2a-2 Summary of Representative Source Term Cases (EPU)

Release Category	MAAP Run	Description	CsI Release Magnitude and Timing	Basis for Selection
LL/I	ESE0127	Loss of containment heat removal scenario with core damage near the time of containment failure (assumed to be in the wetwell airspace region).	7.5E-4 from 34.1 to 42.5 hrs	All of the contribution to this release category comes from TR-2-017 in the EPU model. The representative MAAP case is consistent with this scenario.
LL/L	ESU556a	Large LOCA with no injection or containment heat removal available. Late containment failure in drywell head region. External sprays successful, but only for containment mass addition, not heat removal.	1.4E-5 from 23.8 to 48 hrs	Dominant contributors are LOCA scenarios with no injection or heat removal, but with containment spray from an external source successful (LT-3-046, 96%, LT-3-042, 3%). Timing and release characteristics are similar to the representative MAAP case.

NRC Question 2b:

Describe the steps taken to ensure the technical adequacy of the Level 2 revisions subsequent to the BWROG peer review.

PPL Response:

The BWROG peer review involved the identification of five "B" level facts and observations (F&Os) related to the Level 2 modeling. All of these items were addressed as part of the expanded Level 2 modeling as shown in Table E.2-5 of the license renewal application. All of the modifications to incorporate the expanded Level 2 modeling described above in response to Question 2a were done using the same internal review requirements that exist for any PRA model change. This includes detailed review and sign-off of all related documentation.

The PRA model used in the License Renewal Application is documented and controlled under PPL QA procedures. All documentation packages include an independent technical review and final approval by qualified PPL engineers. Extensive model documentation includes:

1) System Notebooks for all key systems important to risk (e.g. HPCI, RCIC, ADS and MSIVs, RHR, Electrical Distribution system, etc.),
2) An Event Tree Notebook which documents the accident or transient progression from an initiating event to a plant damage state,
3) An Initiating Events Notebook which documents the initiating events considered in the Susquehanna PRA and their associated frequencies,
4) A Human Reliability Notebook which identifies human actions and their associated failure probabilities,
5) A Dependency Matrix Notebook which provides an overall summary of the inter-relationships of plant systems,
6) An Internal Flooding Notebook which identifies the frequencies and the impact of internal floods on key equipment and equipment or train availability, and
7) A Summary Notebook which documents the final PRA model including all software files developed as part of the model and the sensitivities on key input parameters.

Changes to any of the above documentation packages are also done under PPL QA procedures. As with the initial preparation, all changes are prepared, independently reviewed and approved prior to releasing the revised model for general use by plant personnel.

Note that the ASME PRA Standard [1] only includes high level and supporting requirements for LERF (not a full Level 2 model). An industry standard for full Level 2 model development does not yet exist. However, recommendations from industry consultants (recognized experts in Level 2 analysis and are fully cognizant of most of the U.S. BWR Level 2 models that exist) were fully implemented in the development of the Level 2 model for SSES and in the assignment of the phenomenological failure probabilities. Additionally, since the SSES PRA model is a fully integrated Level 1 and Level 2 model as described in response to Question 2a, and since the accepted internal review processes were met in the development of the expanded Level 2 portion of the model, the technical adequacy of the Level 2 model is considered to be consistent with the technical adequacy of the Level 1 model.

NRC Question 3:

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

NRC Question 3a:

The Individual Plant Examination of External Events (IPEEE) fire analysis utilized the IPE internal events models to assess system performance. Indicate whether the original IPE models or the revised IPE models were utilized.

PPL Response:

The information shown in Section E.5.1.7.1 of the license renewal application is based on the 1998 IPEEE audit response results (Reference 2). Based on the time of the audit response preparation, these revised results (compared to the original IPEEE submittal) were based on the IPE version of the internal events model.

Since it is recognized that substantial changes have been implemented to the internal events model since the preparation of the IPEEE and the audit response, the focus of the SAMA analysis was not on the CDF values reported for each Fire Zone, but on the fire scenario development and on the list of impacted systems identified in the IPEEE. This information was then reviewed to determine if additional SAMAs (or existing SAMAs) would help to reduce the potential impact from these scenarios. Subsequently, to account for the revised potential impact if the fire scenarios were to be integrated with the updated internal events model, a factor of two was utilized to develop a Modified Maximum Averted Cost Risk as described in Section E.5.1.8 of the license renewal application.

NRC Question 3b:

Based on a sensitivity study performed by PPL Susquehanna, LLC, the U. S. Nuclear Regulatory Commission concluded in the IPEEE safety evaluation report that the CDF for some fire contributors might be as much as three orders of magnitude higher than the revised values reported in the IPEEE. Discuss this issue and its potential impact on the ER assumption that the fire CDF is about equal to the internal events CDF.

PPL Response:

In full context, the statement in the IPEEE safety evaluation report is qualitative in nature since it is based on the results of one bounding sensitivity study. In any event, a three order of magnitude increase from the originally reported value of 1E-09 per cycle is fairly consistent with the assumption utilized in the SAMA analysis for SSES that the fire CDF risk is about equal to the internal events CDF which is reported as 1.83E-6/yr to 1.97E-6/yr in Section E.2.1 of the license renewal application. As indicated in the license renewal application, the final fire CDF estimate of 4.5E-8 per cycle in the IPE audit response was more than a factor of two lower than the internal events CDF from the IPE. Therefore, the assumption utilized in the SAMA analysis that the fire CDF is approximately equal to the internal events CDF is correct.

NRC Question 4:

Provide the following information concerning the MACCS2 analysis:

NRC Question 4a:

Clarify whether separate ORIGEN calculations were performed for pre-EPU and post-EPU conditions and used to determine population doses for the respective cases.

PPL Response:

A single ORIGEN calculation at the current licensed thermal power of 3489 MWth was utilized as the basis for the pre-EPU and post-EPU conditions for determination of population doses for the respective cases. The ORIGEN fission product results were developed utilizing 3 fuel batches, with slightly different power levels for each batch near the pre-EPU power level. The fission product ORIGEN results for the post-EPU condition were linearly scaled to 4031 MWth (Licensed Power +2%). However, it should be noted that, because of a misunderstanding by contractors, the ORIGEN results for the pre-EPU condition were linearly scaled to 3441 MWth (compared to the actual fission product values at 3489 MWth). The MACCS2 analysis for pre-EPU conditions was then performed using the fission product inventory scaled to 3441 MWth, thus pre-EPU calculation for dose rates is slightly under-represented. Since the conclusions drawn from MACCS2 study are based on the dose rate change between pre-EPU and EPU conditions, the slight under-representation of pre-EPU dose rates is judged not to significantly impact the results and the post-EPU case and the pre-EPU case fission product core inventories differ by approximately 17 percent.

NRC Question 4b:

Based on the March 31, 2006, license amendment request, the EPU power level would be approximately 13% above the current licensed power level. As such, the population dose for EPU conditions would be expected to be approximately 13% greater than for pre-EPU conditions. However, from Table E.3-4, the increase in dose for the dominant release categories (e.g., L2-1, L2-2, and L2-5) ranges from 4 to 11%. Explain this result.

PPL Response:

The License Amendment request for Extended Power Uprate (EPU) submitted on 3/31/2006 (PLA-6002) was withdrawn and replaced with a License Amendment request dated 10/11/2006 (PLA-6076). The revised License Amendment request for EPU was based on the AUG06PreEPU-c and the AUG06EPU PRA models, whereas the original License Amendment request for EPU was FEB06Pre-EPU and FEB06 EPU PRA models. However, the License Amendment request submitted on 10/11/2006 is no different than

the request submitted on 3/31/2006, in terms of expected population dose. The differences between the two PRA models are discussed in the answer to Question 1a.

Population dose, as calculated by MACCS2, has many constituents, each of which is impacted to differing degrees by multiple factors such as release timing (as compared to population evacuation), release duration (e.g., short versus long plumes), land decontamination efforts, relative release fractions between different fission product groups, etc. These multiple constituents and factors interact to result in non-linear impacts on the calculated total population dose.

The exposure pathways considered by MACCS2 during the early phase (i.e., approximately first week) of a postulated release are cloudshine, groundshine, and resuspension inhalation, with cloudshine and groundshine being the major contributors. In the long term phase (i.e., following the first week), exposure pathways considered are groundshine, resuspension inhalation, food and water ingestion, and dose associated with decontamination efforts. Of these long term pathways, groundshine is the predominant contributor, followed by water ingestion.

A simplified breakdown of early and long term doses for the three dominant Susquehanna release categories, as reported by MACCS2, is provided in Table 4b-1. Table 4b-1 demonstrates that for L2-1, the high-early release, the majority of the population dose occurs during the early phase, as generally expected. For releases L2-2 and L2-5, the population dose is driven by long term contributors (primarily groundshine).

Table 4b-2 summarizes the change in dose for the three release categories for the post-EPU and pre-EPU conditions, as a function of early and long term doses. Table 4b-2 demonstrates that long term dose is only impacted a modest amount by an increased reactor power level. This modest impact is attributed to land decontamination impacts, which generally reduce population doses to a baseline amount for a given land area in order to satisfy land habitability criteria. A larger initial release would contaminate a given land area more significantly, but that same land area would then receive greater decontamination to achieve the standard habitability criteria (or else be condemned if habitability criteria could not be achieved). The larger initial release would, however, be expected to impact a slightly larger land area, exposing additional individuals, and introducing additional land subject to decontamination efforts. Thus the larger release associated with the EPU case would not be expected to result in an equal percentage increase in population dose for each release category by long term contributors due to the interplay of the factors associated with interdiction measures.

Regarding early population dose, Table 4b-2 demonstrates a varied dose relationship (increasing from 8% to 17%) for the three release categories as a function of the increase of reactor power between the pre-EPU and post-EPU conditions. Release category L2-1 (High-Early) increases proportionally to reactor power, as might be generally expected.

Release category L2-2 (High-Intermediate) early dose increases, but to a lesser degree (i.e., 8%) than might be expected (i.e., 17%). This modest early dose increase for L2-2 is attributed to the impacts of population relocation modeling outside of the 10 mile emergency planning zone (EPZ). Table 4b-3 demonstrates that approximately 100% of the early dose for release category L2-2 is due to individuals outside the EPZ. MACCS2 models "hot-spot relocation" for individuals outside the EPZ based upon expected dose criteria. If the expected effective dose for individuals in a given grid outside the EPZ exceeds a specified value (1 rem in the Susquehanna Level 3 model, consistent with EPA-400 protective action guidelines), the individuals are relocated at a given time after the arrival of the first plume (12 hours in the Susquehanna model, consistent with the MACCS2 User's Guide). For release category L2-2, three plumes were modeled in MACCS2, with the first plume having very low release fractions (i.e., all < 5E-8). The second plume, with more significant release fractions (e.g., 0.18 for Iodine), was released approximately 14 hours following the first plume, such that hot spot population relocation had occurred for some individuals outside the EPZ prior to arrival of the second plume (based on the dose criteria). This relocation scheme is attributed for mitigating the impacts of the increased reactor power level for release category L2-2. The higher EPU condition release in the first plume would be expected to result in more individuals exceeding the relocation criteria, causing them to be relocated prior to the arrival of the second plume. Thus, some persons who experienced the second plume in the pre-EPU case would have been relocated in the post-EPU case and therefore would not experience the second plume in the post-EPU case. For comparison purposes, it is noted that the three plumes modeled for release category L2-1 (High Early) were released less than 4 hours apart such that hot spot relocation modeling did not play a significant mitigating role in the post-EPU condition.

Release category L2-5 (Moderate-Intermediate) early dose increases approximately 13% for the post-EPU condition rather than 17% as for the full reactor power level increase. The reason for the minor difference is not readily apparent, but is not believed to be related to hot-spot relocation modeling. Release L2-5 is modeled using two plumes, whose releases are 1 hour apart. The minor variance is attributed to the interplay of the various factors involved in dose modeling of the different constituents.

Table 4b-1 Early and Long Term Contributions to Dose

Release Category	Condition	Early		Long Term		Total
		Dose (P-Sv)	% of Total	Dose (P-Sv)	% of Total	Dose (P-Sv)
L2-1 (H/E)	Pre-EPU	1.59E+4	60%	1.04E+4	40%	2.63E+4
	Post-EPU	1.87E+4	64%	1.06E+4	36%	2.93E+4
L2-2 (H/I)	Pre-EPU	8.85E+2	6%	1.42E+4	94%	1.51E+4
	Post-EPU	9.55E+2	6%	1.48E+4	94%	1.57E+4
L2-5 (M/I)	Pre-EPU	1.28E+3	9%	1.24E+4	91%	1.37E+4
	Post-EPU	1.45E+3	10%	1.32E+4	90%	1.46E+4

Table 4b-2 Relative Changes in Dose for EPU Conditions

Release Category	% Change in Dose (Post-EPU vs. Pre-EPU)		
	Early	Long Term	Total
L2-1 (H/E)	17%	2%	11%
L2-2 (H/I)	8%	4%	4%
L2-5 (M/I)	13%	6%	7%

Table 4b-3 Refined Contributions to Early Dose

Release Category	Condition	0 – 10 Mile Early Dose		> 10 Mile Early Dose		Total Early Dose (P-Sv)
		Dose (P-Sv)	% of Total Early Dose	Dose (P-Sv)	% of Total Early Dose	
L2-1 (H/E)	Pre-EPU	2.16E+3	14%	1.38E+4	86%	1.59E+4
	Post-EPU	2.53E+3	12%	1.61E+4	88%	1.87E+4
L2-2 (H/I)	Pre-EPU	1.48E+0	0%	8.84E+2	100%	8.85E+2
	Post-EPU	1.72E+0	0%	9.53E+2	100%	9.55E+2
L2-5 (M/I)	Pre-EPU	2.21E+1	2%	1.26E+3	98%	1.28E+3
	Post-EPU	2.59E+1	2%	1.42E+3	98%	1.45E+3

NRC Question 5:

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

NRC Question 5a:

Tables E.5-1 and E.5-2 include a number of events that are described as preventative maintenance actions (i.e., 024-N-E-DSL-P, 024-I-A-DSL-P, and 024-II-B-DSL-P). Identify the specific structure, system, and components associated with these maintenance actions.

PPL Response:

A more specific description of the maintenance terms in question is provided below:

024-N-E-DSL-P: Diesel Generator 'E' 0G501E in Planned Maintenance
024-I-A-DSL-P: Diesel Generator 'A' 0G501A in Planned Maintenance
024-II-B-DSL-P: Diesel Generator 'B' 0G501B in Planned Maintenance

NRC Question 5b:

Section 5.1.5 includes a list of nine enhancements identified in the IPE. The seventh enhancement, revise guidance regarding reactor vessel control, is listed as "not implemented" and only provides the reasoning that the enhancement has been determined not to be required for safe operation of the plant. Provide a further description of the disposition of this enhancement, and any efforts made to identify SAMA candidates exist to address the associated risk contributors.

PPL Response:

The current version of the BWROG EPGs/SAGs (Reference 3) provides guidance for reactor pressure and level control. Operators are directed to manually open SRVs in the event that any SRV is cycling. After the initial, manual pressure reduction to 935 psig using the SRVs, the EPGs/SAGs direct use of the turbine bypass valves to maintain RPV pressure below 1045 psig. This guidance is not consistent with the EPG-4 guidance that was the basis for the plant enhancement suggested in the IPE. Conformance with the current BWROG guidance is considered to be an adequate basis for excluding the plant enhancement from further consideration in the SAMA analysis; however, there are competing factors related to this issue that have contributed to the changes in the BWROG guidance.

The current EPGs/SAGs bases indicate that cycling the SRVs is undesirable for several reasons, including the following:

- It exerts significant dynamic loads upon the RPV, the SRV tail pipes and supporting structures, and the primary containment.
- Swell and shrink associated with the valve actuations cause RPV water level fluctuations that complicate level control actions.
- Under failure-to-scram conditions, the consequent level and pressure oscillations can result in significant power transients.
- The potential for a stuck open relief valve is increased.

The goals implied by these bases are to create conditions in the RPV that will allow the operators to stabilize the reactor, prevent damage to equipment, and to avoid exacerbation of the scenario.

Previous versions of BWROG guidance, specifically EPG-4, considered post trip evolutions from a different perspective. The EPG-4 perspective was that allowing the SRVs to cycle may increase the time to core damage by precluding the loss of additional inventory that would occur through manual pressure control with the SRVs. This approach could allow additional time for recovery actions, if they are required, but the operation philosophy is based on the need to mitigate future failures.

Including a means of mitigating potential failures is considered to be a positive attribute in a procedure, but not when the benefits of those means may be outweighed by the risks that they impose. For SSES, the safer method of operating the plant is considered to be through manual RPV pressure control rather than cycling the SRVs.

NRC Question 5c:

Section E. 5.1.7.1 discusses the contribution to fire CDF from the dominant fire zones. Although two SAMAs from the internal events analysis were identified to address this risk, no SAMAs unique to the fire analysis were identified. For each fire zone, discuss the potential for SAMAs to address the unique cause of the fire risk, such as SAMAs to reduce the fire initiators, to improve fire detection or suppression, or to relocate components or cabling.

PPL Response:

The conclusion reached during the SAMA development process was that the individual fire zone risks were so low that no SAMAs would be cost effective if they only addressed fire risk. The intent of this RAI response is to provide a quantitative discussion of the fire zone risks and implementation costs for potential SAMAs to support this conclusion.

The bases for this discussion include a few basic calculations and comparisons, similar to those used to quantify SAMA 9, which are outlined below:

- Quantify the maximum averted cost-risk (MACR) associated with each fire zone,
  - Assume internal and external events risk is equal. This implies the same MACR calculated for internal events of $544,000 (per site, post-EPU) can be assigned to external events,
  - Assume all external events risk is due to fire events (fire MACR equals $544,000),
  - Adjust the fire MACR to represent the 95th percentile PSA results case (since this is typically used in the determination of a SAMAs cost effectiveness). For SSES, a multiplier of 2.1 is appropriate ($544,000 * 2.1 = $1,142,400).
  - Use the revised IPEEE fire zone CDFs to determine the fraction of the fire MACR attributable to each fire zone. The fire zone MACRs are assumed to be directly proportional to the fire zone CDFs.
- Identify implementation cost estimates for potential fire SAMAs,
- Compare the implementation cost estimates to the fire zone MACRs and show that the implementation costs are greater than the fire zone MACRs. This indicates that the relevant SAMAs are not cost effective.

As identified in the outline above, the fire zone MACR, which is the largest potential averted cost-risk for a fire zone, can be calculated using assumptions consistent with the SSES ER submittal. The assumption that the internal and external events risks are equal provides a simple means of estimating averted cost-risk values for external events related SAMAs without having to rely on CDF estimates from the IPEEE or an improvised Level 2 analysis. This assumption implies that the external events MACR is the same as the internal events MACR ($275k for Unit 1 and $269k for Unit 2). In order to simplify this demonstration, it is assumed that all external events risk is due to internal fires, which indicates that the Fire MACR is $544,000 ($275,000 + $269,000). Because the determination of a SAMA's cost effectiveness has typically been made based on the 95th percentile PSA results, the external events MACR is multiplied by a factor of 2.1 to simulate use of the 95th percentile results ($544,000 * 2.1 = $1,142,400). The revised IPEEE fire area CDFs can then be used to determine the MACR for each fire area by assuming that the fire area specific MACR is directly proportional to the fire area CDF. Table 5c-1 summarizes the results of this process.

Table 5c-1 MACR Estimates per Fire Zone

Fire Zone	Equipment Lost	CDF, Per cycle	Percent of Total Fire CDF	Base MACR for the Fire Zone (Unit 1)	Base MACR for the Fire Zone (Unit 2)	Base MACR for the Fire Zone (Site)	95th Percentile MACR for the Fire Zone (Site)
1-2B	Division I and II emergency service water (ESW), HPCI	2.10E-09	4.7%	$12,791	$12,512	$25,302	$53,135
0-28B-II	Battery Charger Area, Channels A and B DC	1.30E-09	2.9%	$7,918	$7,745	$15,663	$32,893
0-27C	UCSR, Channels A and B DC Power	3.50E-10	0.8%	$2,132	$2,085	$4,217	$8,856
0-25E	LCSR, HPCI and Div. I RHR	3.30E-09	7.3%	$20,100	$19,661	$39,761	$83,498
Various [1]	HPCI and RCIC	3.30E-08	73.1%	$200,997	$196,611	$397,608	$834,977
0-26H	Panel 1C601 – Auto Initiation of ECCS	5.10E-09	11.3%	$31,063	$30,385	$61,449	$129,042
	Total:	4.52E-08	100.0%	$275,000	$269,000	$544,000	$1,142,400

[1] 15 zones, each with a CDF of 2.1E-9/cycle.

The largest contribution from any single zone, Fire Zone 0-26-H, is about $130,000, which is only $30,000 greater than previous industry estimates of the minimum expected implementation cost for SAMAs requiring hardware changes (References 4 and 5). The actual minimum cost of a hardware modification is debatable and would vary with the application, but the cost of a fire related change, such as cable wrapping or cable re-routing, is known to be relatively high. For example, protecting cables in a fire zone is on the order of $350,000 per zone and re-routing cables is on the order of $1.2 million per zone based on Wolf Creek SAMA estimates (Reference 6) scaled to a per zone basis. These costs are well above the $130,000 MACR for fire zone 0-26H, which implies that they would not be cost effective changes. Procedure changes have implementation costs that are on the order of the fire zone MACRs, but no procedure changes have been identified that could measurably reduce the SSES fire CDF. Previously, as part of the IPEEE, the SSES fire procedures were reviewed and one enhancement was performed related to fire/seismic interaction training, but that change was a high level enhancement that did not impact the CDF. It should be noted that the "Various" fire zone entry in Table 5c-1 represents 15 separate zones of equal CDF such that the contribution from any given zone is only $55,665. Based on these estimates, it is highly unlikely that any SAMAs designed to only impact fire risk would be cost effective.

Further review of each fire zone's characteristics provides additional reassurance that there are no potentially cost beneficial changes that could be implemented for any of the fire zones. Table 5c-2 summarizes the complete list of fire zones considered in the SAMA analysis based on the dominant fire zone contributors from the IPEEE audit response. As can be seen, all of these areas include detection and most of the areas also include automatic suppression capabilities.

Table 5c-2 Fire Suppression and Detection Capabilities of Fire Zones Considered in the SAMA Analysis

Fire Zone	Description	Detection Available?	Fire Suppression Available?
1-2B	Access Corridor	Yes	Yes (auto sprinkler)
0-28B-II	U1 Div I Equipment Room	Yes	No
0-27C	U1 Div I Upper Cable Spreading Room	Yes	Yes (auto sprinkler)
0-25E	U1 Div II Lower Cable Spreading Room	Yes	Yes (auto sprinkler)
0-26H	Control Room	Yes	Yes (manual under floor CO_2)
0-24F	Computer Maintenance Room & Office	Yes	No
0-25A	U2 Div II Lower Cable Spreading Room	Yes	Yes (auto sprinkler)
0-26B	South Electrical Cable Chase	Yes	Yes (manual CO_2)
0-26C	Center Electrical Cable Chase	Yes	Yes (manual CO_2)
0-26D	North Electrical Cable Chase	Yes	Yes (manual CO_2)
0-26S	South Electrical Cable Chase	Yes	Yes (auto CO_2)
0-26T	Center Electrical Cable Chase	Yes	Yes (auto CO_2)
0-26V	North Electrical Cable Chase	Yes	Yes (auto CO_2)
0-27B	U2 Div I Upper Cable Spreading Room	Yes	Yes (auto sprinkler)
0-27F	South Electrical Cable Chase	Yes	Yes (auto CO_2)
0-27G	Center Electrical Cable Chase	Yes	Yes (auto CO_2)
0-27H	North Electrical Cable Chase	Yes	Yes (auto CO_2)
1-3C-N	Equipment Access Area	Yes	No
1-4B	Pipe Penetration Room	Yes	No
1-6I	Fuel Pool Holding Pump Room	Yes	No

The locations that do not include automatic suppression are because of one of the following:

- The location is continuously manned (e.g. Control Room Fire Zone 0-26H)
- Cable chase adjacent to continuously manned Control Room (Fire Zones 0-26B, C and D)
- High radiation area with limited access and limited combustibles (Fire Zones 1-3C-N, 1-4B, and 1-6I)
- Limited combustible area occupied by personnel (Fire Zone 0-24F)

Additionally, a fire impact and cable routing review was performed on the 15 fire zones that are lumped together in the table above. This review revealed that there are numerous reasons for the unavailability of either HPCI or RCIC in these 15 fire zones. The reasons for the unavailability include numerous cables for numerous components, such that there is no one change that could effectively eliminate the risk from all of the fire zones at once. The elimination of the fire impact risk would require multiple changes in multiple fire zones. Cable re-routing would be required to eliminate the impacts. Based on the estimated cost for cable re-routing, approximately $1.2 million per fire zone, correcting the condition for just one fire zone would exceed the MACR Value for this group of fire zones. Finally, it was determined that cable re-routing that would eliminate the condition and not just transfer the condition to an adjacent fire zone may not be possible. Given this understanding of fire risk, the most appropriate SAMAs appear to be those that address fire risk while also reducing the risk from other initiating events. For SSES, SAMAs 1 and 9 fulfilled this requirement.

RAI Question 3b questions the accuracy of the revised IPEEE fire CDF, which is related to this response in that larger fire CDF values would impact the estimates provided in Table 5c-1 and the conclusions of the SAMA identification process. It is agreed that there is a substantial degree of uncertainty in the revised IPEEE fire results, but the analysis method used above does provide considerable margin over that evaluation.

The CDF calculated in the revised fire IPEEE was only 4.52E-8/cycle, which corresponds to a CDF of about 3.62E-08 per reactor year given an 18 month fuel cycle with 15 months of on-line operation. The assumptions that internal and external events risk are equal and that all external events risk is due to internal fires implies that the fire CDF is over 54 times greater than the CDF reported in the revised IPEEE results (given a Unit 1 internal events CDF of 1.97E-06/r-yr and the assumption that the containment response is the same). Further, use of the 2.1 multiplier on the MACR to obtain the 95th percentile PSA results correlates to a CDF that is at least 2 orders of magnitude greater than the revised IPEEE fire CDF. Finally, use of the internal events MACR as the basis for the fire area MACRs suggests that the types of core damage scenarios and containment responses for fire events are similar to those included in the internal events model, as indicated above. In practice, the fire initiators would not include ATWS or LOCA

events, which typically put more stress on the containment. A fire specific Level 2 analysis (which would not include ISLOCAs that dominate the LERF contribution from the internal events model) would likely show a better containment response than the internal events model and a less severe impact on the public.

NRC Question 6:

Provide the following with regard to the Phase 2 cost-benefit evaluations:

NRC Question 6a:

For SAMA 3, Proceduralize Reactor Pressure Vessel Depressurization When Fire Protection System Injection is the Only Makeup Source, indicate what failure events where included for the failure to provide late low pressure injection via the fire main.

PPL Response:

The high level failure events that fail the fire main are:

- Failing the Main Diesel Driven Fire Pump and the Back-up Diesel Driven Fire Pump
- The flow path failing

The diesel driven fire pumps can fail by:

- failure to start
- failure to run
- various valves transferring closed
- failure of the water source
- fire pump being in preventative maintenance
- the Back-up Diesel Driven Fire Pump also has an operator failure to open an isolation valve between the pump and the fire main ring header serving the plant (the plant inside the protected area)

The flow path can fail by:

- various valves transferring closed
- the fire hose failing

NRC Question 6b:

For SAMA 8, Automatic Feedwater Runback for ATWS, the percent reduction in dose risk and Offsite Economic Cost Risk (OECR) is smaller than the reduction in CDF. The reduction in CDF is almost entirely in the low/early release category, which has a very small contribution to dose-risk and OECR. One might expect the reduction in CDF due to ATWS to impact high or medium release categories. Explain this apparent discrepancy.

PPL Response:

In the SSES Level 2 analysis, during scenarios with high power discharge rates to the pool (i.e., ATWS scenario with failure to control RPV level near TAF) containment failure due to dynamic loading is assumed when the suppression pool temperature exceeds 260°F. The containment structural analysis for SSES indicates that the most likely failure location under these conditions is in the wetwell airspace region of containment. The dominant contributors to the core damage sequences that included feedwater runback failures did not include additional or dependent failures to depressurize the RPV. MAAP analyses of ATWS scenarios combined with success of RPV depressurization prior to or near the time of core damage and with early containment failure in the wetwell airspace region were referenced in assigning these scenarios to a low/early release category. Although other containment failure locations and impacts were considered, the majority of the CDF reduction attributed to feedwater runback failures resulted in a corresponding reduction in the low/early release category which as is indicated in the NRC question has a small contribution to dose-risk and OECR.

It should be noted that subsequent to the completion of the SAMA analysis using the FEB06 PRA models, a PRA model revision was issued (AUG06) that resulted in an overall reduction of about 10% in the CDF. Among other changes that were included in that model revision, one of the changes that led to about a 3% reduction in CDF was the removal of illogical cutsets that involved feedwater runback failures. The net affect was to significantly reduce the importance of the feedwater runback failures. As such, the net lower CDF impact combined with the relatively high cost of implementation, regardless of the release category assignment for these scenarios, would make SAMA 8 a very unlikely candidate to be identified as a cost-beneficial enhancement.

NRC Question 6c:

In the discussion of the costs for SAMA 8, it is implied that the cost estimate does not account for inflation. Clarify whether this cost estimate, or any other cost estimates, accounts for inflation.

PPL Response:

None of the cost estimates used in the SSES SAMA analysis were modified to account for inflation.

SAMAs 3 and 11 used cost estimates from the Brunswick SAMA analysis (Reference 7), which were developed only 2 years prior to the SSES submittal. Adjusting those estimates to account for inflation was not considered to be required due to the limited impact it would have on the analysis. SAMA 3 also included the cost of some analytical work as a component of the cost of implementation, but that portion of the implementation cost is considered to be in present day dollars and no adjustments would have been appropriate.

SAMAs 8, 12, and 13 used implementation costs from studies that were at least 10 years old and inflation of those implementation costs to present day dollars would have been appropriate, but doing so would not have impacted the analysis. The fact that the costs were not inflated to present day dollars was noted in the text only to reinforce the margin by which the SAMAs were not cost beneficial.

SAMA 14 did not use an implementation cost, so this RAI is not applicable to that SAMA.

The remaining SAMAs used PPL specific implementation costs that were developed as part of the submittal and were considered to be in present day dollars.

NRC Question 6d:

For SAMA 12, Containment Venting After Core Damage, the analysis shows very little risk reduction. Since this SAMA would reduce the releases for all drywell overpressure failure sequences, a more significant reduction in risk would be expected. Explain the reasons for the small risk reduction for this SAMA.

PPL Response:

The critical piece of information in the SAMA 12 analysis is that procedures exist at SSES to perform containment venting after core damage, but they were not credited in the PRA model used in the SAMA analysis, as discussed in the response to Question 1g. As a result, a new baseline case was developed in the analysis to credit the existing procedures. The quantification of the benefit of SAMA 12 was based on somehow improving the existing procedures at SSES. As such, the averted cost-risk was based on the difference between the revised baseline model where the existing procedures are credited and the configuration where some improvement would be expected through

procedure enhancement. For these conditions, the available improvement is extremely limited, which is reflected in the averted cost-risk for SAMA 12.

While the analysis presented in the SAMA submittal is considered to best reflect actual plant conditions, a sensitivity analysis can be performed to determine the impact of crediting post core damage wetwell venting relative to the baseline PRA model (in which no credit is taken for post core damage wetwell venting). This can be performed using the information included in the SAMA analysis submittal and is defined as the difference between the baseline MMACR and the SAMA 12 MMACR (no other calculations are required).

From Section E.4.6 of the SAMA analysis submittal, the baseline MMACR is $956,000 for pre-EPU conditions and $1,088,000 for post-EPU conditions. The table entitled "SAMA 12 Net value" in Section E.6.10 provides the MMACR values for the conditions in which full post core damage venting is taken, which are $950,029 and $1,083,363 for pre-EPU and post-EPU conditions, respectively. The net values for these cases are provided below assuming that the cost of the procedure change would be $50,000, as assumed in the original analysis:

Pre-EPU Net Value

Baseline MMACR	Sensitivity MMACR (Full post-CD Vent Credit)	Averted Cost-Risk	Cost of Implementation	Net Value
$956,000	$950,029	$5,971	$50,000	-$44,029

Post-EPU Net Value

Baseline MMACR	Sensitivity MMACR (Full post-CD Vent Credit)	Averted Cost-Risk	Cost of Implementation	Net Value
$1,088,000	$1,083,363	$4,637	$50,000	-$45,363

The results of this sensitivity analysis confirm the conclusion of the original SAMA 12 analysis, which is that changes to the SSES guidance on post core damage containment venting would not be cost beneficial. This conclusion is consistent with the relatively low importance of containment overpressurization cases for SSES.

NRC Question 7:

One of the Mark I plants considered in its SAMA identification process (Section E.5.1.4) identified the following SAMA's as potentially cost-beneficial:

a.) Develop guidance/procedures for local, manual control of reactor core isolation cooling following loss of DC power.

b.) Procedures to control containment venting to avoid adverse impacts on emergency core cooling system.

These SAMAs would appear to be applicable to SSES but are not among the Phase 2 SAMAs for SSES. Provide a brief statement regarding the applicability/feasibility of these alternatives for SSES, and a further evaluation (similar to those evaluations provided in the ER) if the alternative could be potentially cost-beneficial at SSES.

PPL Response:

7a.) A procedure does exist at SSES to allow for local, manual control of reactor core isolation cooling following loss of DC power. The procedure requires three Operators and Health Physics support for high radiation area access. The operators will be starting and operating RCIC with the use of flashlights and a hand held tachometer to give them an indication of pump speed. In this scenario the barometric condenser will not be available and consequentially the room temperature will elevate. The implementation of this procedure is not practiced since it would put the plant personnel and plant safety at risk. Considering the complexity of this procedure the PRA model conservatively takes no credit for the use of this procedure. Since the procedure already exists, the SAMA does not need to be identified or explored to determine if it is cost-beneficial.

7b.) SSES does not have a hard pipe containment vent capability. As described in response to NRC Question 1g, the current venting procedure implements the use of containment pressure relief through the existing soft duct work. The strategy includes the pre-alignment of alternate injection systems external to the reactor building since it is likely that the steam environment in the reactor building following containment venting would preclude the use of the ECCS injection systems that reside in the reactor building. As such, a venting strategy that attempts to control containment venting to avoid NPSH impacts on ECCS injection would not be useful as it would not eliminate the subsequent steam environment in the reactor building, and was not pursued further.

References:

[1] ASME RA-Sb-2005 (December 2005) and ASME RA-Sa-2003 (December 2003) Addenda to ASME RA-S-2002, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, April 2002.

[2] PLA-4983, R.G. Byram to USNRC, *Susquehanna Steam Electric Station Response to Audit Issues on IPEEE Submittal Units 1 and 2*, October 15, 1998.

[3] BWR Owners' Group Emergency Procedure Committee, *BWR Owners' Group Emergency Procedure and Severe Accident Guidelines*, Revision 2, March 2001.

[4] Exelon Corporation, *Applicant's Environmental Report- Operating License Renewal Stage; Dresden Nuclear Power Station Units 2 and 3, Appendix F Severe Accident Mitigation Alternatives Analysis*, January 2003. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/dresden-quad.html.

[5] Exelon Corporation, *Applicant's Environmental Report- Operating License Renewal Stage; Quad Cities Nuclear Power Station Units 1 and 2, Appendix F Severe Accident Mitigation Alternatives Analysis*, January 2003. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/dresden-quad.html.

[6] Wolf Creek Nuclear Operating Corporation, *Applicant's Environmental Report-Operating License Renewal Stage; Wolf Creek Generating Station. Attachment F Severe Accident Mitigation Alternatives Analysis*, August 2006. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/wolf-creek.html.

[7] Carolina Power and Light, *Applicant's Environmental Report; Operating License Renewal Stage; Brunswick Steam Electric Plant. Appendix F Severe Accident Mitigation Alternatives*. October 2004. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/brunswick.html.