Perkins, Leslie

From: Ghosh, Tina
Sent: Thursday, September 16, 2010 1:45 PM
To: Eccleston, Charles; Perkins, Leslie
Cc: Gallucci, Ray; Pham, Bo
Subject: RE: ACTION: Hope Creek SAMA Transmittal Memo
Attachments: Final HCGS SAMA Review Report 09-14-2010 ML102580564.docx

Follow Up Flag: Follow up
Flag Status: Flagged

Dear Charles and Leslie,

Please see electronic copy of Hope Creek SAMA appendix transmittal memo which will be coming your way officially shortly.

Best,
Tina

From: Harrison, Donnie
Sent: Thursday, September 16, 2010 1:36 PM
To: Ghosh, Tina; Alexander, Cheryl
Cc: Gallucci, Ray; Howe, Andrew; Pham, Bo; Eccleston, Charles
Subject: RE: ACTION: Hope Creek SAMA Transmittal Memo

I have read through the Hope Creek SAMA ER input. With this e-mail I am concurring on the document.

From: Ghosh, Tina
Sent: Tuesday, September 14, 2010 4:45 PM
To: Alexander, Cheryl
Cc: Gallucci, Ray; Harrison, Donnie
Subject: RE: ACTION: Hope Creek SAMA Transmittal Memo

Dear Cheryl,

IF you haven't started on this concurrence package yet, please use the attached instead for the transmittal memo.
If you already processed it, no worries, I'll make the change in the document in ADAMS during concurrence (the only change is one sentence added in the enclosure).

Thanks,
Tina

From: Ghosh, Tina
Sent: Tuesday, September 14, 2010 10:20 AM
To: Alexander, Cheryl
Cc: Gallucci, Ray; Harrison, Donnie
Subject: ACTION: Hope Creek SAMA Transmittal Memo

Dear Cheryl,

D/169

Could you please prepare the concurrence package for the Hope Creek SAMA evaluation transmittal memo to projects (attached), and obtain an ADAMS number? I have also attached a form 665 (2nd attachment), just the ADAMS number needs to be filled in once assigned.

Ray Gallucci originated the document, but he is out of the office this week. Please let me know if you need anything further.

Thank you very much for your assistance,
Tina
(My new phone number: 301-251-7984)

P.S. Donnie – you can begin your concurrence review by e-mail if you wish. I find that Steve adequately addressed all of Ray's comments.

MEMORANDUM TO: Bo Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

FROM: Donnie Harrison, Chief
Probabilistic Risk Assessment Licensing Branch
Division of Risk Assessment
Office of Nuclear Reactor Regulation

SUBJECT: EVALUATION OF SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR HOPE CREEK GENERATING STATION (TAC NO. ME1831)

The Probabilistic Risk Assessment Licensing Branch (APLA) has completed the enclosed evaluation of severe accident mitigation alternatives (SAMAs) for Hope Creek Generating Station (HCGS). This evaluation is based on the analysis of SAMAs contained in Nuclear, LLC's (PSEG) license renewal application for HCGS, and information provided in responses to requests for additional information (RAIs).

In the environmental report, PSEG Nuclear, LLC identified 14 SAMAs to be potentially cost-beneficial. None of these SAMAs relate to managing the effects of aging. Therefore, they need not be implemented as part of license renewal. APLA's review of the analysis found the methods used and the implementation of those methods to be sound.

Enclosure:
As stated

CONTACT: Ray Gallucci, NRR/DRA
(301) 415-1255

MEMORANDUM TO: Bo Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

FROM: Donnie Harrison, Chief
Probabilistic Risk Assessment Licensing Branch
Division of Risk Assessment
Office of Nuclear Reactor Regulation

SUBJECT: EVALUATION OF SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR HOPE CREEK GENERATING STATION (TAC NO. ME1831)

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Enclosure:
As stated

CONTACT: Ray Gallucci, NRR/DRA
(301) 415-1255

DISTRIBUTION:
DRA R/F TGhosh RGallucci RidsNrrDRA CEccleston

ADAMS Accession No.: ML102580564 **NRR-106**

OFFICE	NRR/DRA/APLA	NRR/DRA/APLA
NAME	RGallucci	DHarrison
DATE	09/ /10	09 / /10

OFFICIAL RECORD COPY

Appendix G

U.S. Nuclear Regulatory Commission Staff Evaluation of Severe Accident Mitigation Alternatives for Hope Creek Generating Station in Support of License Renewal Application Review

G.1 Introduction

PSEG Nuclear, LLC, (PSEG) submitted an assessment of severe accident mitigation alternatives (SAMAs) for the Hope Creek Generating Station (HCGS) as part of the environmental report (ER) (PSEG 2009). This assessment was based on the most recent HCGS probabilistic risk assessment (PRA) available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 (MACCS2) computer code, and insights from the HCGS individual plant examination (IPE) (PSEG 1994) and individual plant examination of external events (IPEEE) (PSEG 1997). In identifying and evaluating potential SAMAs, PSEG considered SAMAs that addressed the major contributors to core damage frequency (CDF) and release frequency at HCGS, as well as SAMA candidates for other operating plants that have submitted license renewal applications. PSEG initially identified 23 potential SAMAs. This list was reduced to 21 unique SAMA candidates by eliminating SAMAs that are not applicable to HCGS due to design differences, have already been implemented at HCGS, would achieve the same risk reduction results that had already been achieved at HCGS by other means, have excessive implementation cost or could be combined with another SAMA candidate. PSEG assessed the costs and benefits associated with each of the potential SAMAs, and concluded in the ER that several of the candidate SAMAs evaluated are potentially cost-beneficial.

Based on a review of the SAMA assessment, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) to PSEG by letter dated May 20, 2010 (NRC 2010a) and, based on a review of the RAI responses, a request for RAI response clarification by teleconference dated July 29, 2010 (NRC 2010b). Key questions concerned: discussing internal and external review comments on the PRA model, including the impact of the 2008 PRA peer review comments on the SAMA analysis results; the process and criteria used to assign containment event tree (CET) end states to release categories; additional details on the seismic analysis; the SAMA screening process and additional potential SAMAs not previously considered; and further information on the costs and benefits of several specific candidate SAMAs and low cost alternatives. PSEG submitted additional information by a letters dated June 1, 2010 (PSEG 2010a) and August 18, 2010 (PSEG 2010b). In the responses, PSEG provided: a listing of open gaps and findings from the 2008 PRA peer review and an assessment of their impact on the SAMA analysis; additional description of how CET end states were assigned to release categories and how representative sequences were selected for each release category; clarification of certain elements of the seismic analysis and an assessment of the impact of seismic assumptions on the external events multiplier; analyses of additional SAMAs; and additional information regarding several specific SAMAs. PSEG's responses addressed the NRC staff's concerns, and resulted in the identification of additional potentially cost-beneficial SAMAs.

An assessment of SAMAs for HCGS is presented below.

G.2 Estimate of Risk for HCGS

PSEG's estimates of offsite risk at HCGS are summarized in Section G.2.1. The summary is followed by the NRC staff's review of PSEG's risk estimates in Section G.2.2.

G.2.1 PSEG's Risk Estimates

Two distinct analyses are combined to form the basis for the risk estimates used in the SAMA analysis: (1) the HCGS Level 1 and Level 2 PRA model, which is an updated version of the IPE (PSEG 1994), and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PRA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent HCGS Level 1 and Level 2 PRA model available at the time of the ER, referred to as the HC108B update. The scope of this HCGS PRA does not include external events.

The HCGS CDF is approximately 5.1×10^{-6} per year as determined from quantification of the Level 1 PRA model at a truncation of 1×10^{-12} per year. When determining the frequency of the source term categories from the sum of the containment event tree (CET) sequences, or Level 2 PRA model, a higher truncation of 5×10^{-11} per year was used and the resulting release frequency (from all release categories, which consist of intact containment, late release, and early release) is approximately 4.4×10^{-6} per year. The latter value was used as the baseline CDF in the SAMA evaluations (PSEG 2009). The CDF is based on the risk assessment for internally-initiated events, which includes internal flooding. PSEG did not explicitly include the contribution from external events within the HCGS risk estimates; however, it did account for the potential risk reduction benefits associated with external events by multiplying the estimated benefits for internal events by a factor of 6.3. This is discussed further in Sections G.2.2 and G.6.2.

The breakdown of CDF by initiating event is provided in Table G-1 (PSEG 2009). As shown in this table, events initiated by loss of offsite power, loss of service water and other transients (manual shutdown and turbine trip with bypass) are the dominant contributors to the CDF. Anticipated transient without scram (ATWS) sequences account for 3% of the CDF, station blackout accounts for 12% of the CDF (PSEG 2010a).

Table G-1. HCGS Core Damage Frequency for Internal Events

Initiating Event	CDF (per year)	% Contribution to CDF[1]
Loss of Offsite Power	9.3×10^{-7}	18
Loss of Service Water (SW)	8.1×10^{-7}	15
Manual Shutdown	7.7×10^{-7}	15
Turbine Trip with Bypass	6.2×10^{-7}	12
Small Loss of Coolant Accident (LOCA) – Water (Below Top of Active Fuel)	2.8×10^{-7}	5
Small LOCA – Steam (Above Top of Active Fuel)	2.3×10^{-7}	4
Loss of Condenser Vacuum	2.0×10^{-7}	4
Fire Protection System Rupture Outside Control Room	1.9×10^{-7}	4
Isolation LOCA in Emergency Core Cooling System (ECCS) Discharge Paths	1.1×10^{-7}	2
Main Steam Isolation Valve (MSIV) Closure	1.1×10^{-7}	2
Internal Flood Outside Lower Relay Room	9.7×10^{-8}	2
Loss of Feedwater	8.8×10^{-8}	2
Loss of Safety Auxiliaries Cooling System	7.9×10^{-8}	2
Reactor Auxiliaries Cooling System (RACS) Common Header Unisolable Rupture	7.6×10^{-8}	1
Unisolable SW A Pipe Rupture in RACS Room	5.7×10^{-8}	1
Unisolable SW B Pipe Rupture in RACS Room	5.7×10^{-8}	1
Others (less than 1% each)	4.1×10^{-7}	8
Total CDF (internal events)	$\mathbf{5.1 \times 10^{-6}}$	**100**

[1]Column totals may be different due to round off.

The Level 2 HCGS PRA model that forms the basis for the SAMA evaluation is essentially a complete revision to the IPE model. The Level 2 model utilizes three containment event trees (CETs) containing both phenomenological and systemic events. The Level 1 core damage sequences are binned into accident classes that provide the interface between the Level 1 and Level 2 CET analysis. The CETs are linked directly to the Level 1 event trees and CET nodes are evaluated using supporting fault trees.

The result of the Level 2 PRA is a set of 11 release or source term categories, with their respective frequency and release characteristics. The results of this analysis for HCGS are provided in Table E.3-6 of ER Appendix E (PSEG 2009). The categories were defined based on the timing of the release, the magnitude of the release, and whether or not the containment remains intact or fails. The frequency of each release category was obtained by summing the frequency of the individual accident progression CET endpoints binned into the release category. Source terms were developed for each of the 11 release categories using the results of Modular Accident Analysis Program (MAAP 4.0.6) computer code calculations.

The offsite consequences and economic impact analyses use the MACCS2 code to determine the offsite risk impacts on the surrounding environment and public. Inputs for these analyses include plant-specific and site-specific input values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mile radius) for the year 2046, emergency response evacuation modeling, and economic data. The core radionuclide inventory corresponds to the end-of-cycle values for HCGS operating at 3917 MWt, which is two percent above the current extended power uprate (EPU) licensed power level of 3,840 MWt. The magnitude of the onsite impacts (in terms of clean-up and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997a).

In the ER, PSEG estimated the dose to the population within 80-kilometers (50-miles) of the HCGS site to be approximately 0.23 person-Sievert (Sv) (22.9 person-roentgen equivalent man [rem]) per year. The breakdown of the total population dose by containment release mode is summarized in Table G-2. Releases from the containment within the early time frame (0 to less than 4 hours following event initiation) and intermediate time frame (4 to less than 24 hours following event initiation) dominate the population dose risk at HCGS.

Table G-2. Breakdown of Population Dose by Containment Release Mode

Containment Release Mode	Population Dose (Person-Rem[1] Per Year)	Percent Contribution
Early Releases (< 4hrs)	11.9	52
Intermediate Releases (4 to <24 hrs)	9.9	43
Late Releases (≥24 hrs)	1.1	5
Intact Containment	<0.1	negligible
Total	**22.9**	**100**

[1]One person-rem = 0.01 person-Sv

G.2.2 Review of PSEG's Risk Estimates

PSEG's determination of offsite risk at HCGS is based on the following three major elements of analysis:

- The Level 1 and 2 risk models that form the bases for the 1994 IPE submittal (PSEG1994), and the external event analyses of the 1997 IPEEE submittal (PSEG 1997),

- The major modifications to the IPE model that have been incorporated in the HCGS PRA, and

- The MACCS2 analyses performed to translate fission product source terms and release frequencies from the Level 2 PRA model into offsite consequence measures.

Each of these analyses was reviewed to determine the acceptability of PSEG's risk estimates for the SAMA analysis, as summarized below.

The NRC staff's review of the HCGS IPE is described in an NRC report dated April 23, 1996 (NRC 1996). Based on a review of the IPE submittal and responses to RAIs, the NRC staff concluded that the IPE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the HCGS IPE has met the intent of GL 88-20 (NRC 1988).

During the performance of the IPE, transients involving heating, ventilation, and air conditioning (HVAC) failure were determined to contribute inordinately to the CDF. This was labeled a vulnerability and a procedure to provide alternate ventilation was developed. The implementation of this procedure removed this vulnerability. Credit for this procedure was taken in the HCGS IPE submittal. No other vulnerabilities were identified. In the ER, PSEG indicated that there were three improvements identified in the process of performing the IPE. Two of the improvements were performing refined calculations to allow increased credit for existing plant design features. The third was developing a procedure for operation of the Safety Auxiliaries Cooling System in severe accident conditions. All of these improvements are stated to have been implemented (PSEG 2009).

There have been twelve revisions to the IPE model since the 1994 IPE submittal. A listing of the changes made to the HCGS PRA since the original IPE submittal was provided in the ER (PSEG 2009) and in response to an RAI (PSEG 2010a) and is summarized in Table G-3. A comparison of internal events CDF between the 1994 IPE and the current PRA model indicates a decrease of about a factor of ten in the total CDF (from 4.7×10^{-5} per year to 5.1×10^{-6} per year). This reduction can be attributed to significant changes in success criteria, modeling details and removal of conservatism.

Table G-3. HCGS PRA Historical Summary

PRA Version	Summary of Changes from Prior Model	Total CDF[1] (per year)
1994	IPE Submittal	4.7×10^{-5}

PRA Version		Summary of Changes from Prior Model	Total CDF[1] (per year)
Model 0 9/1994	-	Credit taken for beyond design basis performance of Safety Auxiliaries Cooling System (SACS) and Station Service Water System (SSWS) based on updated success criteria calculations.	1.3×10^{-5}
Model 1.0 7/1999	-	Integrated the Level I and II models	1.9×10^{-5}
	-	Updated the database	
	-	Further developed sequence end states	
	-	Developed fault trees for special initiators	
	-	Reviewed dependent operator actions	
Model 1.3[2] 10/2000	-	Requantified two important human error probabilities	9.3×10^{-6}
	-	Revised treatment of disallowed maintenance to credit plant procedures and operating practices.	
	-	Revised common cause failure assessment	
	-	Eliminated core spray room cooling dependency on SACS based on review of room heat up calculations	
	-	Added models for breaks outside containment and manual shutdown	
	-	Updated ATWS analysis	
Model 2003A 8/2003	-	Incorporated resolution of 1999 BWROG peer review Facts and Observations (Attachment 14 to PSEG 2005)	3.1×10^{-5}
	-	Converted from NUPRA to CAFTA software	
	-	Performed completely new human reliability assessment	
	-	Revised accident sequence definitions	
	-	Performed new MAAP calculations for extended power uprate (EPU) conditions	
	-	Updated data	
	-	Modified system models	
	-	Updated common cause failure analysis	
	-	Added internal flood accident sequences	
Rev. 2.0 10/2004	-	Modified 480 VAC dependencies	1.7×10^{-5}
	-	Modified SACS success criteria	
	-	Modified SACS-SW Human Error Probabilities	
Model 2005C[3] 2/2006	-	Removed conservatism in the SACS-SW success criteria	9.8×10^{-6}
	-	Included more detailed logic for AC power supplies	
	-	Removed conservatism in operator action human error probabilities (HEPs)	
	-	Reduced turbine trip initiating event frequency	

PRA Version	Summary of Changes from Prior Model	Total CDF[1] (per year)
HC108A 8/2008	BWROG Peer Reviewed - Incorporated seasonal success criteria for SACS and SSWS - Updated internal flooding scenarios and initiating event frequencies to be consistent with ASME PRA standard - Credited use of portable battery charger for Station Blackout scenarios - Reassessed human error probabilities using Electric Power Research Institute (EPRI) human reliability analysis (HRA) calculator - Updated evaluation of dependent operator actions	7.6×10^{-6}
HC108B[4] 12/2008	- Credited procedure changes for local manual manipulation of SSWS valves under LOOP conditions - Removed conservatism in modeling of 120 VAC inverter room cooling logic - Updated SACS pump failure probabilities to be consistent with Bayesian update values	5.1×10^{-6} (4.4×10^{-6})

[1]Total CDF includes internal floods. Prior to Model 2003A, IPE internal flood analysis was retained.

[2]Changes for Model 1.3 includes those for prior intermediate Models 1.1 and 1.2. All changes were considered minor.

[3]Changes for Model 2005C includes those for prior intermediate Models 2005A and 2005B. All changes to Models 2005A and 2005B were considered minor.

[4]Model HC108B truncation limit was decreased to 1×10^{-12} per year from 5×10^{-11} per year utilized for the HC108A and 2005 models. The CDF in parentheses is the result based on the higher truncation limit.

The CDF value from the 1994 IPE (4.7×10^{-5} per year) is in the upper third of the values reported for other BWR 3/4 plants. Figure 11.2 of NUREG-1560 shows that the IPE-based total internal events CDF for BWR 3/4 plants ranges from 9×10^{-8} per year to 8×10^{-5} per year, with an average CDF for the group of 2×10^{-5} per year (NRC 1997b). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes. The current internal events CDF results for HCGS (5.1×10^{-6} per year) are comparable to that for other plants of similar vintage and characteristics.

The NRC staff considered the peer reviews performed for the HCGS PRA, and the potential impact of the review findings on the SAMA evaluation. In the ER (PSEG 2009) and in response to an NRC staff RAI (PSEG 2010a) and in other unrelated submittals (PSEG 2005), PSEG described three BWROG Peer Reviews for the HCGS PRA. The first was a pilot of the BWROG peer review process conducted in 1996 of PRA Model 0. The second, conducted in 1999, reviewed PRA Model 1.0. The third, conducted in 2008, reviewed the HC108A Model.

The 1999 peer review identified no Level A (extremely important) and 80 Level B (important) Facts and Observations (F&Os). It was stated that these F&Os were resolved and incorporated in the 2003A PRA Model (PSEG 2005).

The 2008 peer review of the HC108A model was requested by PSEG because of the significant changes in PRA methods since the prior peer review. This peer review was performed using the Nuclear Energy Institute peer review process (NEI 2007) and the ASME PRA Standard (ASME 2005) as endorsed by the NRC in Regulatory Guide 1.200, Rev. 1 (NRC 2007). In the ER PSEG summarizes the results of the peer review by reporting the number of ASME Standard's supporting requirements (SRs) that were assessed to meet each of the standard's Capability Categories. Of the 301 SRs applicable to HCGS, 286 were found to meet the requirements for Capability Category II or higher, seven met Capability Category I and eight did not meet any Capability Category. Capability Category II is described as follows (ASME 2005): 1) the scope and level of detail has resolution and specificity sufficient to identify the relative importance of significant contributors at the component level including human actions, as necessary, 2) plant-specific data/models are used for significant contributors, and 3) departures from realism will have small impact on the conclusions and risk insights as supported by good practices.

In the ER, PSEG indicated that the SRs identified as "not met" were addressed in the HC108B model. In response to an NRC staff RAI, PSEG provided a listing and discussion of the resolution of the SRs that only met Capability Category I and of other Peer Review Finding-level F&Os (PSEG 2010a). It should be noted that a Finding-level F&O is essentially equivalent to and replaces the previously used Level A and B F&Os and is defined as an observation that is necessary to address to ensure 1) the technical adequacy of the PRA, 2) the capability/robustness of the PRA update process, and 3) the process for evaluating the necessary capability of the PRA technical elements (NEI 2007).

Of the seventeen identified SRs and findings, thirteen were stated to have been resolved as part of the HC108B PRA update and re-assessed as meeting Capability Category II at a minimum as a result of additional investigation, analysis and/or documentation. Four of the SRs and findings remain open. In the discussion of the status and impact of these open items, PSEG concluded that the resolution of each would not impact the conclusions of the SAMA risk assessment. Two of the open items were documentation issues. One issue was related to the need for additional plant-specific data for important events. PSEG indicated that a review of HCGS recent experience indicates "no anomalous behavior" and that minor changes to component unavailability and unreliability values would not change the conclusions of the SAMA risk evaluation. The fourth issue was related to the identification, characterization and documentation of model uncertainties. PSEG indicated that a number of sensitivity evaluations were performed and that other areas of the HCGS PRA were investigated for potential impact on the PRA results but none were found to rise to the level of being candidates for modeling uncertainty. PSEG concluded that the resolution of this open item would not impact the conclusions of the SAMA evaluation (PSEG 2010a). PSEG further states that the HCGS PRA treatment of model uncertainty is considered to meet the requirements of the latest NRC guidance on model uncertainty, NUREG-1855 (NRC 2009).

In the initial response to the NRC staff RAIs (PSEG 2010a) PSEG's discussion of the resolution of the supporting requirements that were not met addressed only six items whereas the initial listing in the ER indicated that there were eight SRs that were not met. In response to the request for clarification PSEG pointed out that the draft peer review report identified eight SRs as not met, while the final review report identified only six SRs as not being met (PSEG 2010b).

The NRC staff considers PSEG's disposition of the peer review findings to be reasonable and that final resolution of the findings is not likely to impact the results of the SAMA analysis.

The Revision HC108B model reflects the current (as of the date of the ER submittal) HCGS configuration and design. The licensee states that HCGS risk management personnel have reviewed plant modifications and procedure changes since the HC108B model freeze date. No changes were identified that required PRA model updates and therefore the licensee concluded that none of the plant modifications and procedure changes since the HC108B PRA update would impact the conclusions of the SAMA analysis. (PSEG 2010a, PSEG 2010b)

In response to an RAI, PSEG described the overall quality assurance program applicable to the HCGS PRA and its updates by providing descriptions of significant governing PSEG procedures. These procedures address the overall risk management program, risk management documentation including quality requirements for preparation, review and approval, configuration control and PRA model updates. The procedures appear to address the appropriate requirements.

Given that the HCGS internal events PRA model has been peer-reviewed and the peer review findings were all addressed, and that PSEG has satisfactorily addressed NRC staff questions regarding the PRA, the NRC staff concludes that the internal events Level 1 PRA model is of sufficient quality to support the SAMA evaluation.

As indicated above, PSEG does not maintain a current HCGS external events PRA that explicitly models seismic and fire initiated core damage accidents that can be linked with the current Level 2 and 3 PRA. However, the models developed for seismic and fire events in the IPEEE were partially updated in 2003 to utilize revised initiating event frequencies and conditional core damage probabilities based on the 2003A internal events PRA Model. These results were used to identify SAMAs that address important fire and seismic risk contributors, as discussed below in Section G.3.2. The updated seismic and fire core damage results are described in ER Section E.5.1.7

The HCGS IPEEE was submitted in July 1997 (PSEG 1997), in response to Supplement 4 of Generic Letter 88-20 (NRC 1991a). The submittal included a seismic PRA, an internal fire PRA, and an evaluation of high winds, external flooding, and other hazards. While no fundamental weaknesses or vulnerabilities to severe accident risk in regard to the external events were identified, two potential enhancements were identified as discussed below. In a letter dated July 26, 1999 (NRC 1999), the NRC staff concluded that PSEGs IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the HCGS IPEEE has met the intent of Supplement 4 to Generic Letter 88-20.

The HCGS IPEEE seismic analysis utilized a seismic PRA following NRC guidance (NRC 1991a). The seismic PRA included: a seismic hazard analysis, a seismic fragility assessment, a seismic systems analysis, and quantification of seismic CDF.

The seismic hazard analysis estimated the annual frequency of exceeding different levels of ground motion. Seismic CDFs were determined for both the EPRI (EPRI 1989) and the Laurence Livermore National Laboratory (LLNL) (NRC 1994) hazard assessments. The seismic fragility assessment utilized the walkdown procedures and screening caveats in EPRI's seismic margin assessment methodology (EPRI 1991). Fragility calculations were made for about 90 components and, using a screening criterion of median peak ground acceleration (pga) of 1.5 g which corresponds to a 0.5 pga high confidence low probability of failure (HCLPF) capacity, a total of 17 components were screened in. The seismic systems analysis defined the potential seismic induced structure and equipment failure scenarios that could occur after a seismic event and lead to core damage. The HCGS IPE event tree and fault tree models were used as the starting point for the seismic analysis. Quantification of the seismic models consisted of convoluting the seismic hazard curve with the appropriate structural and equipment seismic fragility curves to obtain the frequency of the seismic damage state. The conditional probability of core damage given each seismic damage state was then obtained from the IPE models with appropriate changes to reflect the seismic damage state. The CDF was then given by the product of the seismic damage state probability and the conditional core damage probability.

The seismic CDF resulting from the HCGS IPEEE was calculated to be 3.6×10^{-6} per year using the LLNL seismic hazard curve and 1.0×10^{-6} per year using the EPRI seismic hazard curve. Both utilized the HCGS Model 0 internal events PRA, with a CDF of 1.3×10^{-5} per year for quantification of non-seismic failures.

The HCGS IPEEE did not identify any vulnerability due to seismic events or any potential improvements to reduce seismic risk. The IPEEE noted, however, that fire water tanks are not seismically robust and hence no credit was taken for the fire protection system in the seismic PRA. This is discussed further in Section G.3.2.

Subsequent to the IPEEE, PSEG updated the seismic PRA utilizing conditional core damage probabilities from the 2003A PRA model modified to reflect the seismic human reliability assessment that was performed to support the IPEEE, referred to as the HCGS 2003 External Events Update (PSEG 2009). The resulting seismic CDF using the EPRI seismic hazard curves is 1.1×10^{-6} per year. In the ER, PSEG provided a listing and description of the top ten seismic core damage contributors. The dominant seismic core damage contributors with a CDF of 1×10^{-8} per year or more are listed in Table G-4. In response to an NRC staff RAI, PSEG also determined the updated seismic CDF using the LLNL seismic hazard curve and the total seismic CDF was determined to be 3.6×10^{-6} per year. The seismic CDF utilizing the LLNL hazard curves for dominant seismic core damage contributors are also listed in Table G-4.

Table G-4. Dominant Contributors to the Seismic CDF

		Based on EPRI Seismic Hazard Curves		Based on LLNL Seismic Hazard Curves	
Basic Event ID	**Seismic Sequence Description**	**CDF (per year)**	**% Contribution to Seismic CDF**	**CDF (per year)**	**% Contribution to Seismic CDF**
%IE-SET36	Seismic-Induced Equipment Damage State SET-36 (Impacts – 120V PNL481)	6.7×10^{-7}	60	2.5×10^{-6}	70
%IE-SET18	Seismic-Induced Equipment Damage State SET-18 (Impacts – LOOP)	3.1×10^{-7}	27	3.3×10^{-7}	9
%IE-SET37	Seismic-Induced Equipment Damage State SET-37 (Impacts – 125V)	6.8×10^{-8}*	6	4.4×10^{-7}	12
%IE-SET35	Seismic-Induced Equipment Damage State SET-35 (Impacts – 120V PNL482, RSP)	4.6×10^{-8}	4	1.6×10^{-7}	5
%IE-SET38	Seismic-Induced Equipment Damage State SET-38 (Impacts – 1E panel room Ventil.)	2.1×10^{-8}	2	5.4×10^{-8}	2

* In response to an RAI, PSEG indicated that the value reported in the ER page E-99 for this contributor was in error and should be that given in the IPEEE - 6.8×10^{-8} per year (PSEG 2010a).

For both hazard curves, the largest contributor to seismic CDF is a seismic-induced loss of all four divisions of 1E 120 VAC instrumentation distribution panels that leads directly to core damage. Other significant contributors are: for the EPRI hazard curves, a seismic-induced loss of offsite power which together with non-seismic random failures leads to core damage and, for the LLNL hazard curves, a seismic induced failure of all 125 VDC 1E power to loads that lead directly to core damage. The failure of all four 1E 120 VAC divisions and failure of all 125 VDC occur at a relatively high ground acceleration (a median failure at 1.08g and 1.47g, respectively) while the loss of offsite power occurs at a relatively low ground acceleration (a median failure of 0.31g) (PSEG 1997).

The NRC staff requested the applicant assess the impact the higher seismic CDF resulting from the use of the LLNL hazard curves would have on the external events multiplier and the results of the SAMA analysis as well as the impact of the increased CDF for important seismic sequences on the identification and evaluation of SAMAs for these sequences. This is discussed further below and in Sections G.3.2 and G.6.2.

The HCGS IPEEE fire analysis employed EPRI's fire-induced vulnerability evaluation (FIVE) methodology (EPRI 1993) to perform a fire compartment interaction analysis (FCIA) and a quantitative screening analysis. This was then followed by a PRA quantification of the unscreened compartments.

The FCIA identified 209 fire compartments meeting the FIVE criteria for the entire plant. The quantitative screening utilized a threshold fire ignition frequency obtained using the FIVE methodology and the assumptions that all fires resulted in a reactor trip or more severe transient and that any fire in a compartment damaged all the equipment and cables in the compartment. Using the assessed screening fire frequency and conservatively determined screening conditional core damage probabilities (CCDPs) from the Model 0 internal events PRA resulted in screening out (at a CDF of less than 1×10^{-6} per year) of all but 38 fire compartments.

The analysis for the unscreened areas employed a detailed probabilistic assessment of each possible fire initiator/target combination including intermediate fire growth stages. Fire damage calculations used a modified version of the FIVE fire propagation methodology. No explicit credit was taken for manual or automatic fire suppression. Final quantification utilized FIVE fire data and refined CCDPs from the Model 0 internal events PRA. The resulting fire induced CDF was calculated to be 8.1×10^{-5} per year. A walkdown and verification process was employed to verify that the assumptions and calculations were supported by the physical condition of the plant.

The HCGS IPEEE did not identify any vulnerabilities due to internal fires or any potential improvements to reduce internal fire risk.

Subsequent to the IPEEE, PSEG updated the fire PRA to incorporate more recent fire initiating event frequencies based on information in the 2002 NRC fire database and conditional core damage probabilities from the 2003A PRA model, referred to as the 2003 HCGS External Events Update. The resulting fire CDF is 1.7×10^{-5} per year.

In the ER, PSEG provided a listing and description of the top ten fire core damage contributors. The important fire core damage contributors with a CDF of 1×10^{-7} per year or more are listed in Table G-5. As can be seen from these results the fire risk at HCGS is dominated by panel fires in the control room.

Table G-5. Important Contributors to Fire CDF

Basic Event ID	Fire Area Description	CDF per year	% Contribution to Fire CDF

%IE-FIRE03	Control Room Fire Scenario Small Cab_3 (Loss of Emer. Bat.)	5.3×10^{-6}	31
%IE-FIRE02	Control Room Fire Scenario Small Cab_2 (Loss of SSWS)	4.4×10^{-6}	25
%IE-FIRE01	Control Room Fire Scenario Small Cab_1 (Loss of SACS)	3.8×10^{-6}	22
%IE-FIRE28	Compartment 5339 Fire Scenario 5339_2	7.5×10^{-7}	4
%IE-FIRE37	DG room (D) Fire Scenario 5304_2	7.0×10^{-7}	4
%IE-FIRE20	DG room (C) Fire Scenario 5306_2	6.7×10^{-7}	4
%IE-FIRE38	Compartment 3425/5401 Fire Scenario 5401_1	5.9×10^{-7}	3
%IE-FIRE06	Control Room Fire Scenario Large Cab_1 (MSIV Closure)	5.1×10^{-7}	3

In the ER, PSEG states that an effective comparison between the internal events PRA results and the fire analysis results is not possible because neither the plant response model or the fire modeling methodology used in the updated fire model is current. PSEG identified in the ER areas where fire CDF quantification may introduce levels of uncertainty different from those expected in the internal events PRA, including a number of conservatisms in the fire modeling, as follows:

- Several system models assume the systems are unavailable or are unrecoverable in a fire. For example, any fire is assumed to result in a plant trip, even if it is not severe. Other examples are provided in the ER.
- Bounding fire modeling assumptions are used for many fire scenarios. For example, all cables are damaged in a fire even if they are enclosed in cable trays or conduit. Other examples are provided in the ER.
- Because of a lack of industry experience with regard to crew performance during the types of fires modeled in the fire PRA, the characterization of crew actions in the fire PRA is generally conservative.

PSEG's conclusion is that while some of the conservatisms have been addressed in the updated fire model, the result is still believed to be conservative.

Considering the above discussion, the conservatisms in the updated fire PRA model as currently understood, and the response to the NRC staff RAIs, the NRC staff concludes that the fire CDF of 1.7×10^{-5} per year is reasonable for the SAMA analysis.

The IPEEE analysis of high winds, floods and other (HFO) external events indicated that each of the events identified in NUREG-1407 (NRC 1991b) had a core damage contribution of less than the screening criterion of 1×10^{-6} per year. This was done by either showing compliance with the 1975 Standard Review Plan criteria or by a bounding analysis that demonstrated that the CDF contribution was less than the screening criterion. For the SAMA analysis, PSEG assumed a CDF contribution of 1×10^{-6} per year for each of high winds, external floods, transportation and nearby facilities, detritus, and chemical releases, for a total HFO CDF contribution of 5×10^{-6} per year (PSEG 2009).

Although the HCGS IPEEE did not identify any vulnerabilities due to HFO events, two improvements to reduce risk were identified as described below.

For high winds, the HCGS design was compared to the SRP criteria and found to have a CDF contribution less than the screening criterion. A walkdown was performed to evaluate high wind hazards and as a result work was initiated to install a missile shield in front of a door into the Technical Support Center. This improvement has been implemented.

For external floods the HCGS was found to be adequately protected from the postulated occurrence of the probable maximum hurricane surge with wave run-up coincident with the 10% exceedance high tide. HCGS was also found to comply with the latest probable maximum precipitation criteria. A walkdown confirmed that there were no severe accident vulnerabilities due to external floods.

A review of transportation and nearby facility accidents confirmed that there were no severe accident vulnerabilities from these accidents. During the review it was discovered that in a single year there had been some unauthorized shipments of explosives on the Delaware River in the vicinity of the HCGS. The U.S. Coast Guard (USCG), which controls such shipments, was contacted and procedures were put in place to prevent such shipments in the future. This improvement has been implemented.

The NRC staff asked about the status and potential impact on the SAMA analysis of a liquefied natural gas (LNG) terminal planned for Logan Township, New Jersey, upstream on the Delaware River from the HCGS site (NRC 2010a). In response to the RAI, PSEG discussed the current status of the LNG terminal as well as the regulatory controls for LNG marine traffic and LNG ship design and the safety record for LNG shipping (PSEG 2010a). The LNG terminal remains in the planning stage and no construction has begun. Further, the state of Delaware has denied applications for several required environmental permits and approvals. PSEG concluded that based on the regulatory process and controls for assuring the safety and security of LNG ships, the safety record of LNG ships and the uncertainty of the planned terminal, consideration of potential SAMAs associated with the possible future terminal is not warranted. The NRC staff agrees with this conclusion.

As indicated in the ER (PSEG 2009), a multiplier of 6.3 was used to adjust the internal event risk benefit associated with a SAMA to account for external events. This multiplier was based on a total external event CDF of 2.3×10^{-5} per year. This CDF is the sum of the updated fire

CDF of 1.7 × 10^{-5} per year, the updated seismic CDF of 1.1 × 10^{-6} per year, and the HFO CDF of 5 × 10^{-6} per year. The external event CDF is thus approximately 5.3 times the internal events CDF of 4.4 × 10^{-6} per year used in the SAMA analysis at a truncation of 5 × 10^{-11} per year. The higher truncation used for determining the multiplier is to be consistent with that used to determine the release category frequencies and that used to evaluate the fire and seismic CDFs. The total CDF is thus 6.3 times the internal events CDF (PSEG 2009).

As indicated above, in response to an NRC staff RAI, PSEG determined the seismic CDF based on the LLNL hazard curve to be 3.6 x 10^{-6} per year (PSEG 2010a). If this is utilized instead of the value using the EPRI hazard curve, the total external events CDF is 2.6 x 10^{-5} per year and the external events multiplier is 6.8. The impact of this revised multiplier on the SAMA assessment is discussed further in Section G.3.2 and Section G.6.2.

The NRC staff reviewed the general process used by PSEG to translate the results of the Level 1 PRA into containment releases, as well as the results of the Level 2 analysis, as described in the ER and in response to NRC staff requests for additional information (PSEG 2010a, PSEG 2010b). The HCGS Level 2 PRA model is essentially a complete revision of the IPE Level 2 model, including completely revised containment event trees and system fault trees and completely updated thermal hydraulic analyses, incorporating the latest emergency operating procedures (EOPs), severe accident guidelines (SAGs), and emergency action level (EAL) and implementation using the CAFTA software.

The current Level 2 model utilizes a set of three containment event trees (CETs) containing both phenomenological and systemic events. The Level 1 core damage sequences are grouped into core damage accident classes with similar characteristics. All the sequences in an accident class are then input to one of the three CETs by linking the level 1 event tree sequences with the level 2 CET. The CETs are analyzed by the linking of fault trees that represent each CET node. These fault trees are based on the Level 1 models for the system or function as modified for Level 2 considerations of timing, procedures, access or dependencies including recovery actions as documented in the HCGS emergency Operating Procedures and Severe Accident Management Guidelines.

Each CET end state represents a radionuclide release to the environment and is characterized by one of thirteen release bins based on magnitude and timing of release. Magnitude is given by CsI release fraction: High (H) > 10%, Moderate (M) 1% to 10%, Low (L) 0.1% to 1%, Low-Low (LL) <0.1% and negligible or no release<< 0.1%. Timing is given by time of initial release from the time of declaration of a General Emergency: Early (E) < 4 hours, Intermediate (I), 4 to 24 hours and Late (L) > 24 hours. The assignment of each end state to a given release bin is made on the basis of a MAAP calculation for the accident sequence or a similar MAAP calculated sequence. The thirteen release bins were subsequently refined into eleven release categories for input to the MACCS consequence calculations by dividing the high early release bin into three release categories (high pressure, low pressure and breaks outside containment) and combining several of the end states with Low and Low-Low release magnitudes.

The frequency of each release category was obtained by summing the frequency of the contributing CET end states. The release characteristics for each release category were developed by using the results of Modular Accident Analysis Program (MAAP 4.0.6) computer code calculations. A representative MAAP case for each of the release categories was chosen based on a review of the Level 2 cutsets and the dominant types of scenarios that contribute to the results. The MAAP case chosen for each release category was generally the case with the highest consequence (PSEG 2010a). A description of the representative MAAP case for each release or source term category is provided in Table E.3-5 of the ER. The release categories, their frequencies, and release characteristics are presented in Table E.3-6 of the ER (PSEG 2009).

It is noted for the SAMA analysis the CET end state and release category frequencies were determined using a truncation value of 5×10^{-11} per year. This results in a total CDF of approximately 4.4×10^{-6} per year, which is about 16 percent less that the internal events CDF of 5.1×10^{-6} per year obtained when a truncation of 1×10^{-12} per year. The NRC staff considers that use of the release frequency rather than the Level 1 CDF will have a negligible impact on the results of the SAMA evaluation because the external event multiplier and uncertainty multiplier used in the SAMA analysis (discussed in Section G.6.2) have a much greater impact on the SAMA evaluation results than the small error arising from the model quantification approach.

The NRC staff review of release category information noted an apparent discrepancy in the release magnitude and release timing assigned for ST5 and ST7 and requested the applicant to clarify the reasons for these discrepancies (NRC 2010a). Both these release categories involve loss of containment heat removal with subsequent containment failure, core damage and fission product release. For ST5 the containment failure is in the wet well while for ST7 the containment failure is in the drywell. While the drywell failure would be expected to result in a higher release than a wet well failure, the reverse is true for the results provided in the ER. Further, the release timings were found to be slightly different even though the core damage times were the same. In response to the RAI, PSEG pointed out that the wet well failure for ST5 occurred below the water level and, due to the loss of suppression pool water inventory, resulted in significantly less cesium iodide removal from the safety relief valve (SRV) flow to the suppression pool for ST5 than for the drywell failure case ST7 (PSEG 2010a). The differing release pathways resulted in the slightly different times for the initiation of release to the environment.

Based on the NRC staff's review of the Level 2 methodology, the applicant's responses to RAIs and the fact that the Level 2 model was reviewed in more detail as part of the 2008 BWROG peer review and found to be acceptable (except for two documentation related findings which would not impact the SAMA analysis), the NRC staff concludes that the Level 2 PRA provides an acceptable basis for evaluating the benefits associated with various SAMAs.

The NRC staff reviewed the process used by PSEG to extend the containment performance (Level 2) portion of the PRA to an assessment of offsite consequences (essentially a Level 3 PRA). This included consideration of the source terms used to characterize fission product releases for the applicable containment release categories and the major input assumptions used in the offsite consequence analyses. The MACCS2 code was utilized to estimate offsite consequences. Plant-specific input to the code includes the source terms for each category and the reactor core radionuclide inventory (both discussed above), site-specific meteorological data, projected population distribution within an 80-kilometer (50-mile) radius for the year 2046, emergency evacuation modeling, and economic data. This information is provided in Section E.3 of Appendix E to the ER (PSEG 2009).

PSEG used the MACCS2 code and a core inventory from a plant specific calculation at end of cycle to determine the offsite consequences of activity release. In response to an NRC staff RAI, PSEG stated that the MACCS2 analysis was based on the core inventory used in the NRC-approved Alternate Source Term for HCGS (PSEG 2010a).

All releases were modeled as being from the top of the reactor containment building and at low thermal content (ambient). Sensitivity studies were performed on these assumptions and indicated little or no change in population dose or offsite economic cost. Assuming a ground level release decreased dose risk and cost risk by 6 percent and 7 percent, respectively. Assuming a buoyant plume decreased dose risk and cost risk by 1 percent. Based on the information provided, the staff concludes that the release parameters utilized are acceptable for the purposes of the SAMA evaluation.

PSEG used site-specific meteorological data for the 2004 calendar year as input to the MACCS2 code. The development of the meteorological data is discussed in Section E.3.7 of Appendix E to the ER. The data were collected from onsite and local meteorological monitoring systems. Sensitivity analyses using MACCS2 and the meteorological data for the years 2005 through 2007 show that use of data for the year 2004 results in the largest dose and economic cost risk. Missing meteorological data was filled by (in order of preference): using data from the backup met pole instruments (10-meter), using corresponding data from another level of the main met tower, interpolation (if the data gap was less than 6 hours), or using data from the same hour and a nearby day (substitution technique). The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for use by MACCS2. The NRC staff notes that previous SAMA analyses results have shown little sensitivity to year-to-year differences in meteorological data and concludes that the use of the 2004 meteorological data in the SAMA analysis is reasonable.

The population distribution the licensee used as input to the MACCS2 analysis was estimated for the year 2046 using year 1990 and year 2000 census data as accessed by SECPOP2000 (NRC 2003) as a starting point. In response to an NRC staff RAI, PSEG stated that the transient population was included in the 10-mile EPZ, and included prior to the population projection (PSEG 2010a). A ten year population growth rate was estimated using the year 1990 to year 2000 SECPOP2000 data and applied to obtain the distribution in 2046. The baseline population was determined for each of 160 sectors, consisting of sixteen directions for each of ten concentric distance rings to a radius of 50 miles surrounding the site. The SECPOP2000 census data from 1990 and 2000 were used to determine a ten year population growth factor for each of the concentric rings. The population growth was averaged over each ring and applied uniformly to all sectors within each ring. The NRC staff requested PSEG provide an assessment of the impact on the SAMA analysis if a wind-direction weighted population estimate for each sector were used (NRC 2010a). In response to the RAI, PSEG stated that the impacts associated with angular population growth rates on PDR and OECR are minimal and bounded by the 30% population sensitivity case (PSEG 2010a). This is based on the relatively even wind distribution profile surrounding the site, the tendency for lateral dispersion between sectors, and the use of mean values in the analysis. A sensitivity study was performed for the population growth at year 2040. A 30 percent increase in population resulted in a 29 percent increase in dose risk and a 30 percent increase in cost risk. In response to an NRC staff RAI, PSEG stated that the radial growth rates used in the MACCS2 analysis provides a more conservative population growth estimate than using 'whole county' data for averaging (PSEG 2010a). PSEG also identified that the population sensitivity case of 30 percent growth was approximately equivalent to adding 5.9 percent to the 10-year growth rate. The NRC staff considers the methods and assumptions for estimating population reasonable and acceptable for purposes of the SAMA evaluation.

The emergency evacuation model was modeled as a single evacuation zone extending out 16 kilometers (10 miles) from the plant (the emergency planning zone – EPZ). PSEG assumed that 95 percent of the population would evacuate. This assumption is conservative relative to the NUREG-1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the emergency planning zone. The evacuated population was assumed to move at an average radial speed of approximately 2.8 meters per second (6.3 miles per hour) with a delayed start time of 65 minutes after declaration of a general emergency (KLD 2004). A general emergency declaration was assumed to occur at the onset of core damage. The evacuation speed is a time-weighted average value accounting for season, day of week, time of day, and weather conditions. It is noted that the longest evacuation time presented in the study (i.e., full 10 mile EPZ, winter snow conditions, 99th percentile evacuation) is 4 hours (from the issuance of the advisory to evacuate). Sensitivity studies on these assumptions indicate that there is minor impact to the population dose or offsite economic cost by the assumed variations. The sensitivity study reduced the evacuation speed by 50 percent to 1.4 m/s. This change resulted in a 2 percent increase in population dose risk and no change in offsite economic cost risk. The NRC staff concludes that the evacuation assumptions and analysis are reasonable and acceptable for the purposes of the SAMA evaluation.

Site specific agriculture and economic parameters were developed manually using data in the 2002 National Census of Agriculture (USDA 2004) and from the Bureau of Economic Analysis (BEA 2008) for each of the 23 counties surrounding HCGS, to a distance of 50 miles.

Therefore, recently discovered problems in SECPOP2000 do not impact the HCGS analysis. The values used for each of the 160 sectors were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using data in the 2002 National Census of Agriculture (USDA 2004) and the Bureau of Economic Analysis (BEA 2008). Food ingestion was modeled using the new MACCS2 ingestion pathway model COMIDA2 (NRC 1998a). For HCGS, less than one percent of the total population dose risk is due to food ingestion.

In addition, generic economic data that is applied to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 1.96, representing cost escalation from 1986 to April 2008 was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation.

The NRC staff concludes that the methodology used by PSEG to estimate the offsite consequences for HCGS provides an acceptable basis from which to proceed with an assessment of risk reduction potential for candidate SAMAs. Accordingly, the NRC staff based its assessment of offsite risk on the CDF and offsite doses reported by PSEG.

G.3 Potential Plant Improvements

The process for identifying potential plant improvements, an evaluation of that process, and the improvements evaluated in detail by PSEG are discussed in this section.

G.3.1 Process for Identifying Potential Plant Improvements

PSEG's process for identifying potential plant improvements (SAMAs) consisted of the following elements:

- Review of the most significant basic events from the current, plant-specific PRA and insights from the HCGS PRA Group,
- Review of potential plant improvements identified in, and original results of, the HCGS IPE and IPEEE,
- Review of SAMA candidates identified for license renewal applications for six other U.S. nuclear sites, and
- Review of generic SAMA candidates from NEI 05-01 (NEI 2005) to identify SAMAs that might address areas of concern identified in the HCGS PRA.

Based on this process, an initial set of 23 candidate SAMAs, referred to as Phase I SAMAs, was identified. In this Phase I evaluation, PSEG performed a qualitative screening of the initial list of SAMAs and eliminated SAMAs from further consideration using the following criteria:

- The SAMA is not applicable at HCGS due to design differences,
- The SAMA has already been implemented at HCGS,
- The SAMA would achieve results that have already been achieved at HCGS by other means, or
- The SAMA has estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at HCGS.

Based on this screening, one SAMA was eliminated, and one additional SAMA was eliminated by subsuming it into another SAMA, leaving 21 SAMAs for further evaluation. The results of the Phase I screening analysis is given in Table E.5-3 of Appendix E to the ER. The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table E.6-1 of Appendix E to the ER. In Phase II a detailed evaluation was performed for each of the 21 remaining SAMA candidates, as discussed in Sections G.4 and G.6 below. To account for the potential impact of external events, the estimated benefits based on internal events were multiplied by a factor of 6.3, as previously discussed.

G.3.2 Review of PSEG's Process

PSEG's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events, but also included explicit consideration of potential SAMAs for important fire and seismic initiated core damage sequences. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from risk reduction worth (RRW) perspectives at HCGS, and included selected SAMAs from prior SAMA analyses for other plants.

PSEG provided a tabular listing of the Level 1 PRA basic events sorted according to their RRW (PSEG 2009). SAMAs impacting these basic events would have the greatest potential for reducing risk. PSEG used a RRW cutoff of 1.006, which corresponds to about a 0.6 percent change in CDF given 100-percent reliability of the SAMA. This equates to a benefit of approximately $100,000 (after the benefits have been multiplied by a factor of 6.3 to account for external events), which is the minimum implementation cost associated with a procedure change. As a result of this review, 11 SAMAs were identified.

In the level 1 importance review, PSEG stated for the important initiating events that "This initiator event is a compilation of industry and plant specific data. (No specific SAMA identified)." The NRC staff requested that PSEG provide assurance that for each of these initiating events there is not a dominant contributor for which a potential SAMA to reduce the initiating event frequency or mitigate the impact of the initiator would be viable. In response to this RAI, PSEG discussed each of the initiators and the previously identified SAMAs that would reduce the importance of the initiator by mitigating other failures in the core damage sequences associated with these initiators (PSEG 2010a). In response to a request for clarification PSEG indicated that HCGS specific failures that are contributors to the initiating event frequencies that pose a unique vulnerability are typically captured and corrected within existing procedures, e.g., the corrective action program, and can result in procedure changes, plant modifications and training enhancements aimed at reducing further recurrence (PSEG 2010b). Based on this discussion and a review of the latest ten years of HCGS Licensee Event Reports, the NRC staff concludes that it is unlikely that further HCGS data review will identify any additional cost beneficial SAMAs beyond those already identified.

The PSEG response to the NRC staff request for clarification provided additional information on initiators modeled utilizing a fault tree approach rather then being based on initiating event data. For the loss of station auxiliaries cooling system initiating event (%IE-SACS), PSEG identified and evaluated SAMA 42, "Installation of SACS Standby Diesel-Powered Pump" (PSEG 2010b).

For an event involving the station service water system (NR-IE-SWS, "Nonrecovery of %IE-SWS"), the importance review identified two SAMAs as potentially mitigating this event: SAMA 3, "Install Back-up Air Compressor to Supply Air-Operated Valves (AOVs)," and SAMA 4, "Provide Procedural Guidance to Cross-Tie Residual Heat Removal (RHR) Trains." In response to an NRC staff RAI to clarify the source and applicability of these SAMAs to this event, PSEG discussed the modeling involving the NR-IE-SWS event and the applicability of the SAMAs in terms of the more general loss of decay heat removal function of which the event is associated and other SAMAs that would mitigate this event (PSEG 2010a). Based on this discussion, the NRC staff concludes that this event is adequately addressed in the SAMA analysis.

For a significant number of the Level 1 events reviewed no SAMAs were identified with the reason stated to be that "...based on low contribution to L[evel] 1 risk and engineering judgment, the anticipated implementation costs of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit" (PSEG 2009). In response to an NRC staff RAI, PSEG provided a revised assessment of each of these events that showed that each was either already addressed by an existing SAMA or that no effective SAMAs could be identified (PSEG 2010a).

The NRC staff also requested PSEG to specifically consider the following proposed SAMAs to address basic events on the Level 1 importance list for which no SAMA was identified (NRC 2010a):

- Install a diverse redundant temperature controller to address basic event SAC-XHE-MC-DF01, "dependent failure of miscalibration of temperature controller HV-2457S." In response to the RAI, PSEG explained that this SAMA is not warranted since 1) procedures are already in place to manually control the affected system which, if credited using a failure probability of 0.1, would reduce the RRW for this basic event to 1.005, the review threshold, and 2) controller miscalibration would be observed during normal operation (PSEG 2010a).

- Install flood barriers to address basic event %FL-FPS-5302, "internal flood outside lower relay room." In response to the RAI, PSEG clarified that the ER incorrectly did not identify SAMA 8, "Convert Selected Fire Protection Piping from Wet Pipe to Dry Pipe System," to address this event and further explained that the proposed SAMA is not necessary because the conversion to a dry pipe system was considered preferable to developing flood barriers considering the multiple doors that exist in the corridor outside the relay room (PSEG 2010a).

- Install a spray shield to address basic event SWS-MOV-VF-SPRAY, "flood – spray causes motor-operated valve (MOV) failure in reactor auxiliaries cooling system (RACS) compartment." In response to the RAI, PSEG explained that the proposed SAMA is not required because the PRA conservatively assumes that all relevant spray events cause failure of the MOVs and that an assumption of 1 in 10 events causing failure would reduce the RRW for this basic event to below the 1.005 review threshold (PSEG 2010a).

- Installation of a passive containment vent to address basic event NR-RHRVENT-INT, "fail to initiate vent given failure to initiate residual heat removal (RHR) in suppression pool cooling (SPC)." This proposed SAMA would also be an alternative to SAMA 4, "Provide Procedural Guidance to Cross-tie RHR Trains." In response to the RAI, PSEG indicated that changing the existing hard pipe venting system to a passive vent design is not considered feasible due to the loss in response flexibility provided by the existing hard pipe venting system and the potential for premature opening of the rupture disks in the passive design (PSEG 2010a). In response to a request for clarification PSEG identified and evaluated SAMA 41, "Installation of Passive Hardened Containment Ventilation Pathway" (PSEG 2010b).

In summary, as a result of PSEG's reconsideration of basic events for which no SAMA had been identified in the ER, two new SAMAs were identified: SAMA 41, "Installation of Passive Hardened Containment Ventilation Pathway," and SAMA 42, "Installation of SACS Standby Diesel-Powered Pump." A Phase II cost-benefit evaluation was performed for each of these additional SAMAs, which is discussed in Section G.6.2.

In response to an NRC staff RAI, PSEG extended the review down to a RRW of 1.005 to account for a revised external events multiplier of 6.8, which was discussed in Section G.2.2. This extended review identified one additional SAMA as follows: SAMA RAI 5.j-IE1, "Install a Key Lock Switch for Bypass of the MSIV Low Level Isolation Logic" (PSEG 2010a, PSEG 2010b). The Phase II cost-benefit evaluation of this SAMA is discussed in Section G.6.2.

PSEG also provided and reviewed the Level 2 PRA basic events, down to a RRW of 1.006, for cutsets stated to contribute to large early release. This review did not identify any additional SAMAs. In response to an NRC staff RAI, PSEG revisited this review using only the cutsets from the high and moderate release categories, which contribute over 99 percent of the population dose-risk and offsite economic cost risk (PSEG 2010a). The Level 2 basic events for the remainder of the release categories were not included in the review so as to prevent high frequency-low consequence events from biasing the importance listing. In addition the review was extended down to a RRW of 1.005 to account for a revised external events multiplier of 6.8. The revisited review identified one additional SAMA, not identified in the extended Level 1 review discussed above, as follows: SAMA RAI 5p-1, "Install an Independent Boron Injection System." The Phase II cost-benefit evaluation of this SAMA is discussed in Section G.6.2.

The NRC staff also requested PSEG to specifically consider the following proposed SAMAs (NRC 2010a):

1. Installation of a curb or barrier inside the drywell to prevent early failure of the drywell shell due to shell melt-through. This proposed SAMA addresses basic event CNT-DWV-FF-MLTFL, "drywell (DW) shell melt-through failure due to containment failure," for which no SAMA was identified. In response to the RAI, PSEG explained that this proposed SAMA would not be effective in reducing risk because 1) injection is not available and, without cooling, the core debris would degrade the barrier to the point of failure, and 2) an early unscrubbed release pathway is already available as a result of pre-existing containment failures resulting from loss of decay heat removal (PSEG 2010a).

2. Replacement of the normally open floor and equipment drain MOVs with fail-closed air-operated valves (AOVs). While this proposed SAMA is stated in the ER to be a more costly alternative to SAMA 5, "restore AC power with onsite gas turbine generator," the NRC staff noted in the RAI that it might also be more effective and therefore have a larger benefit. In response to the RAI, PSEG provided a Phase II cost-benefit evaluation of this proposed SAMA, which is discussed in Section G.6.2.

One additional SAMA, SAMA 18, "replace a return fan with a different design in service water pump room," was identified in the ER based on a review of PRA insights from the HCGS PRA Group and was identified to address two basic events on the Level 1 basic events importance list.

PSEG reviewed the cost-beneficial Phase II SAMAs from prior SAMA analyses for five General Electric BWR and one Westinghouse PWR sites. PSEG's review determined that all but two of the Phase II SAMAs reviewed were either already represented by an existing SAMA, are already implemented at HCGS, have low potential for risk reduction at HCGS, or were not applicable to the HCGS design. This review resulted in two SAMAs being identified by PSEG for HCGS.

PSEG's disposition of industry SAMA "auto align 480V AC portable station generator" is stated to be addressed by SAMA 5, "restore AC power with onsite gas turbine generator." The NRC staff noted that the industry SAMA could mitigate events other than those addressed by SAMA 5 and requested PSEG to evaluate the industry SAMA (NRC 2010a). In response to an NRC staff RAI PSEG identified and evaluated an additional SAMA to automate the alignment of the portable 480V AC generator (PSEG 2010a, PSEG 2010b). The cost-benefit evaluation of this additional SAMA is discussed in Section G.6.2.

The ER states that an industry SAMA to "develop a procedure to open the door of the EDG buildings upon the higher temperature alarm" was included in the HCGS SAMA analysis. The NRC staff noted that no such SAMA was evaluated and asked PSEG to clarify this discrepancy (NRC 2010a). In response to the RAI, PSEG explained that this SAMA would not reduce HCGS risk since EDG room cooling issues are small contributors to risk at HCGS and that the statement in the ER is incorrect (PSEG 2010a).

The NRC asked PSEG to address a SAMA to "increase boron concentration or enrichment in the SLC system," which was determined to be potentially cost-beneficial in the Duane Arnold SAMA analysis (NRC 2010a). In response to the RAI, PSEG explained that this SAMA would have a negligible benefit at HCGS because SLC is automatically initiated at HCGS and the basic events the SAMA addresses (related to manual SLC initiation) are not on the importance lists (PSEG 2010a).

PSEG considered the potential plant improvements described in the IPE in the identification of plant-specific candidate SAMAs for internal events. Review of the IPE led to no additional SAMA candidates since the three improvements identified in the IPE have already been implemented at HCGS. (PSEG 2009)

Based on this information, the NRC staff concludes that the set of SAMAs evaluated in the ER, together with those identified in response to NRC staff RAIs, addresses the major contributors to internal event CDF.

Although the IPEEE did not identify any fundamental vulnerabilities or weaknesses related to external events, two improvements related to HFO events were identified. The two improvements have been implemented at HCGS (PSEG 2009). In the ER PSEG also identified three post IPEEE site changes to determine if they could impact the IPEEE results and possibly lead to a SAMA. From this review no additional SAMAs were identified.

In a further effort to identify external event SAMAs, PSEG identified the top 10 fire scenarios contributing to fire CDF based on the results of the updated HCGS fire PRA model and reviewed the top 8 fire scenarios for potential SAMAs. These 8 scenarios are the only HCGS fire scenarios having a benefit equal to or greater than approximately $100,000, which is the approximate value of implementing a procedure change at a single unit at HCGS. The maximum benefit for a fire area is the dollar value associated with completely eliminating the fire risk in that fire area. SAMAs having an implementation cost of less than that of a procedure change, or $100,000, are unlikely. As a result of this review, PSEG identified six Phase I SAMAs to reduce fire risk. The SAMAs identified included both procedural and hardware alternatives (PSEG 2009). The NRC staff concludes that the opportunity for fire-related SAMAs has been adequately explored and that it is unlikely that there are additional potentially cost-beneficial, fire-related SAMA candidates.

For seismic events, PSEG reviewed the top 10 seismic sequences contributing to seismic CDF based on the results of the 2003 HCGS seismic analysis and initially reviewed the top 2 seismic sequences for potential SAMAs. These two sequences are the only HCGS seismic sequences having a benefit equal to or greater than approximately $100,000, which is the approximate value of implementing a procedure change at a single unit at HCGS. The maximum benefit for a seismic sequence is the dollar value associated with completely eliminating the seismic risk for that sequence. SAMAs having an implementation cost of less than that of a procedure change, or $100,000, are unlikely. As a result of this review, PSEG identified three Phase I SAMAs to reduce seismic risk (PSEG 2009).

In response to an NRC staff RAI, PSEG revised the review of seismic sequences to account for the increased maximum benefit of each sequence resulting from the use of the LLNL seismic hazard curve instead of the EPRI curve used initially, as discussed in Section G.2.2. This resulted in two additional seismic sequences having a benefit equal to or greater than the $100,000 threshold. As a result of the review of these sequences three additional SAMAs were identified: 1) reinforce 1E 125V DC distribution panels 1A/B/C/D-D-417, 2) reinforce 1E 120V AC distribution panels 1A/B/C/DJ482, and 3) reinforce the 1E 120V AC 481 distribution panels to 1.0g Seismic Rating (PSEG 2010a, PSEG 2010b). The cost-benefit evaluation of these additional SAMAs is discussed in Section G.6.2.

The NRC staff concludes that the opportunity for seismic-related SAMAs has been adequately explored and that it is unlikely that there are additional potentially cost-beneficial, seismic-related SAMA candidates.

As stated earlier, other external hazards (high winds, external floods, transportation and nearby facility accidents, release of on-site chemicals, and detritus) are below the IPEEE threshold screening frequency, or met the 1975 SRP design criteria, and are not expected to represent vulnerabilities. Nevertheless, PSEG reviewed the IPEEE results and subsequent plant changes for each of these external hazards and determined that either 1) the maximum benefit from eliminating all associated risk was less than approximately $100,000, which is the approximate value of implementing a procedure change at a single unit at HCGS, or 2) only hardware enhancements that would significantly exceed the maximum value of any potential risk reduction were available. As a result of this review, PSEG identified no additional Phase I SAMAs to reduce HFO risk (PSEG 2009). The NRC staff concludes that the licensee's rationale for eliminating other external hazards enhancements from further consideration is reasonable.

The NRC staff noted that, while the generic SAMA list from NEI 05-01 (NEI 2005) was stated to have been used in the identification of SAMAs for HCGS, it was not specifically reviewed to identify SAMAs that might be applicable to HCGS but rather was used to identify SAMAs that might address areas of concern identified in the HCGS PRA (NRC 2010a). The NRC staff asked PSEG to provide further information to justify that this approach produced a comprehensive set of SAMAs for consideration. In response to the RAI, PSEG explained that, based on the early SAMA reviews, both the industry and NRC came to realize that a review of the generic SAMA list was of limited benefit because they were consistently found to not be cost-beneficial and that the real benefit was considered to be in the development of SAMAs generated based on plant specific risk insights from the PRA models (PSEG 2010a). Furthermore, while the generic list does include potential plant improvements for plants having a similar design to HCGS, plant designs are sufficiently different that the specific plant improvements identified in the generic list are generally not directly applicable to HCGS, and require alteration to specifically address the HCGS design and risk contributors or otherwise would be screened as not applicable to the HCGS design. For these reasons, PSEG concludes that the real value of the NEI 05-01 generic SAMA list is as an idea source to generate SAMAs that address important contributors to HCGS risk. The NRC staff accepts PSEG's conclusion.

The NRC staff noted that the 23 Phase I SAMA numbers were not consecutive from 1 to 23, but rather were intermittently numbered between 1 and 40 and requested clarification on the process used to develop the Phase I SAMA list (NRC 2010a). In response to the RAI, PSEG clarified that the original SAMA list was generated from an importance list using the HC108A PRA model, and that review of the subsequent importance list developed using the HC108B PRA model determined that certain SAMAs were either no longer applicable or were subsumed into other existing SAMAs (PSEG 2010a). PSEG further clarified that the resulting set of Phase I SAMAs was not renumbered to be consecutive so as to avoid configuration management errors that could occur when working with other documentation and supplemental files. Also, SAMAs identified from the review of external events were given a starting number of 30 so as to avoid overlap with SAMAs developed for internal events.

As indicated above two Phase 1 SAMAs were screened out. SAMA 38, "Enhance Fire Water System (FWS) and Automatic Depressurization System (ADS) for Long-term Injection," was screened out on the basis that a procedure has been implemented to address the actions associated with this SAMA. However, as discussed in ER Section E.5.1.7.2.2, this SAMA requires enhancement to the FWS, including strengthening the fire water tanks. In response to an NRC staff RAI, PSEG provided an additional discussion regarding this SAMA and how enhancements to the FWS have been addressed as part of the implementation of the current procedure (PSEG 2010a). The additional discussion indicated that the seismic sequence from which this SAMA originated was a low magnitude earthquake for which there would be a relatively small chance for failure of the FWS. Consequently, strengthening the FWS would have little impact on the sequence and, upon reevaluation, is not needed as part of SAMA 38. PSEG therefore concluded that the procedure implements the remaining requirements of this SAMA.

SAMA 14, "Alternate Room Cooling for Service Water (SW) Rooms," was screened out on the basis that it was subsumed into SAMA 4, "cross-tie RHR pump trains." It is described as providing an alternate means of opening Torus Vent Valves, but no basic event in the importance lists is identified as being addressed by this SAMA. In response to an NRC staff RAI, PSEG provided a further discussion of this SAMA and its disposition (PSEG 2010a). SAMA 14 was originally developed to address important containment venting failure events. The importance of these events would be reduced if the need to vent containment is reduced by addressing failure of SW room cooling which leads to loss of containment heat removal. It was subsequently determined that SAMA 4 was the most viable SAMA to address the loss of containment heat removal and SAMA 14 was subsumed into SAMA 4. PSEG also indicated that a loss of SW room cooling could also be addressed by a new SAMA that provides an alternate room cooling strategy for the SW room using procedures and portable fans. A Phase II detailed evaluation was performed for this new SAMA, referred to as SAMA RAI 7.a-1, "enhance procedures and provide additional equipment to respond to loss of all service water pump room supply or return fans" (PSEG 2010a).

The NRC staff questioned PSEG about lower cost alternatives to some of the SAMAs evaluated (NRC 2010a), including:

- Establishing procedures for opening doors and/or using portable fans for sequences involving room cooling failures.
- Extending the procedure for using the B.5.b low pressure pump for non-security events to include all applicable scenarios, not just SBOs.
- Utilizing a portable independently powered pump to inject into containment.

In response to the RAIs, PSEG addressed the suggested lower cost alternatives (PSEG 2010a). A new SAMA, SAMA RAI 7.a-1 discussed above, was assessed in a Phase II detailed evaluation for the first item while the other two items are effectively covered by existing procedures. This is discussed further in Section G.6.2.

The NRC staff notes that the set of SAMAs submitted is not all-inclusive, since additional, possibly even less expensive, design alternatives can always be postulated. However, the NRC staff concludes that the benefits of any additional modifications are unlikely to exceed the benefits of the modifications evaluated and that the alternative improvements would not likely cost less than the least expensive alternatives evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered.

The NRC staff concludes that PSEG used a systematic and comprehensive process for identifying potential plant improvements for HCGS, and that the set of potential plant improvements identified by PSEG is reasonably comprehensive and, therefore, acceptable. This search included reviewing insights from the plant-specific risk studies, and reviewing plant improvements considered in previous SAMA analyses. While explicit treatment of external events in the SAMA identification process was limited, it is recognized that the prior implementation of plant modifications for fire and seismic risks and the absence of external event vulnerabilities reasonably justifies examining primarily the internal events risk results for this purpose.

G.4 Risk Reduction Potential of Plant Improvements

PSEG evaluated the risk-reduction potential of the 21 remaining SAMAs that were applicable to HCGS, and additional SAMAs identified in response to NRC staff RAIs. The SAMA evaluations were performed using realistic assumptions with some conservatism. On balance, such calculations overestimate the benefit and are, therefore, conservative.

PSEG used model re-quantification to determine the potential benefits. The CDF, population dose reductions, and offsite economic cost reductions were estimated using the HCGS PRA model. The changes made to the model to quantify the impact of SAMAs are detailed in Section E.6 of Appendix E to the ER (PSEG 2009). Table G-6 lists the assumptions considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The estimated benefits reported in Table G-6 reflect the combined benefit in both internal and external events. The determination of the benefits for the various SAMAs is further discussed in Section G.6.

The NRC staff questioned the assumptions used in evaluating the benefit or risk reduction estimate of SAMA 5, "Restore AC Power with Onsite Gas Turbine Generator." The assessment of this SAMA assumed this was equivalent to reducing the probability of failure to cross tie the HCGS emergency diesel generators. This assumption does not provide credit for the gas turbine generator (GTG) in the situation where all the emergency generators are unavailable (NRC 20010a). In response to the RAIs, PSEG provided the results of a sensitivity study which the NRC staff subsequently noted did not appear to include credit for the hardware changes included in the cost estimate (NRC 2010b). In response to the request for clarification, PSEG provide the results of a re-evaluation of SAMA 5 that incorporated the additional capability for mitigating a more complete set of loss of offsite power initiators consistent with the hardware changes proposed (PSEG 2010b). The revised results are provided in Table G-6.

For SAMAs that specifically addressed fire events (i.e., SAMA 30, "Provide Procedural Guidance for Partial Transfer of Control Functions from Control Room to the Remote Shutdown Panel," SAMA 31, "Install Improved Fire Barriers in the Main Control Room (MCR) Control Cabinets Containing the Primary Main Steam Isolation Valve (MSIV) Control Circuits," SAMA 32, "Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from Diesel Generator (DG) Rooms," SAMA 33, "Install Division II 480V AC Bus Cross-ties," SAMA 34, "Install Division I 480V AC Bus Cross-ties," and SAMA 35, "Relocate, Minimize and/or Eliminate Electrical Heaters in Electrical Access Room"), the reduction in fire CDF and population dose was not directly calculated (in Table G-6 this is noted as "Not Estimated"). For these SAMAs, an estimate of the impact was made based on general assumptions regarding: the approximate contribution to total risk from external events relative to that from internal events; the fraction of the external event risk attributable to fire events; the fraction of the fire risk affected by the SAMA (based on information from the 2003 HCGS External Events Update); and the assumption that the SAMA eliminates 90 percent (SAMAs 30, 32, 33, and 34), 99 percent (SAMA 35), or all (SAMA 31) of the fire risk affected by the SAMA. Specifically, it is assumed that the contribution to risk from external events is approximately 5.3 times that from internal events, and that internal fires contribute 74 percent of this external events risk. The fire basic events impacted by the SAMA are identified and the portion of the total fire risk contributed by each of these fire basic events determined. For SAMA 31, the benefit or averted cost risk from reducing the fire risk affected by the SAMA is then calculated by multiplying the ratio of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS. For the other fire SAMAs, the benefit or averted cost risk from reducing the fire risk affected by the SAMA is then calculated by multiplying the ratio of 90 percent, or 99 percent (SAMA 35), of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS. These SAMAs were assumed to have no additional benefits in internal events.

The NRC staff questioned the calculated impact for SAMA 35 which assumed that 90 percent of the fire risk affected by the SAMA was eliminated rather than the 99 percent stated in the ER (NRC 2010a). In response to the RAI, PSEG provided a revised evaluation using 99 percent (PSEG 2010a). The revised results are provided in Table G-6.

For SAMAs that specifically addressed seismic events (i.e., SAMA 36, "Provide Procedural Guidance for Loss of All 1E 120V AC Power," and SAMA 37, "Reinforce 1E 120V AC Distribution Panels") the reduction in seismic CDF and population dose also was not directly calculated. As was done for fire SAMAs, an estimate of the impact of seismic SAMAs was made based on general assumptions regarding: the approximate contribution to total risk from external events relative to that from internal events; the fraction of the external event risk attributable to seismic events; the fraction of the seismic risk affected by the SAMA (based on information from the 2003 HCGS External Events Update); and the assumption that the SAMA eliminates 50 percent (SAMA 36) or 90 percent (SAMA 37) of the seismic risk affected by the SAMA. Specifically, it is assumed that the contribution to risk from external events is approximately 5.3 times that from internal events, and that seismic events contribute 5 percent of this external events risk. The seismic basic events impacted by the SAMA are identified and the portion of the total seismic risk contributed by each of these seismic basic events determined. The benefit or averted cost risk from reducing the seismic risk affected by the SAMA is then calculated by multiplying the ratio of 50 percent (SAMA 36), or 90 percent (SAMA 37), of the seismic risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS. These SAMAs were assumed to have no additional benefits in internal events.

The NRC staff has reviewed PSEG's bases for calculating the risk reduction for the various plant improvements and concludes, with the above clarifications, that the rationale and assumptions for estimating risk reduction are reasonable and generally conservative (i.e., the estimated risk reduction is higher than what would actually be realized). Accordingly, the NRC staff based its estimates of averted risk for the various SAMAs on PSEG's risk reduction estimates.

Table G-6. SAMA Cost/Benefit Screening Analysis for HCGS[a]

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
1 – Remove Automatic Depressurization System (ADS) Inhibit from Non-ATWS Emergency Operating Procedures	**The probability that operators fail to inhibit ADS was reduced to 0.1 from 1.0.**	**26**	**29**	**5.3M**	**14.9M**	**200K**
3 – Install Back-up Air Compressor to Supply AOVs	**The probability that operators fail to restore service water was reduced to 0.5 from 1.0.**	**16**	**16**	**3.3M**	**9.4M**	**700K**
4 – Provide Procedural Guidance to Cross-Tie RHR Trains	**The probability that operators fail to recover RHR was reduced to 0.1 from 0.35.**	**12**	**21**	**4.4M**	**12.4M**	**100K**
5[b] – Restore AC Power with Onsite Gas Turbine Generator	**The probability that operators fail to cross-tie the emergency diesel generators (EDGs) was reduced to 0.1 from 1.0. In response to an NRC staff RAI, the GTG failure probability, maintenance unavailability, and human error probability were set to 0.**	**9**	**11**	**2.2M**	**6.3M**	**2.05M**
7 – Install Better Flood Protection Instrumentation for Reactor Auxiliaries Cooling System (RACS) Compartment	The probability that operators fail to isolate locally a service water rupture in the RACS compartment was reduced to 0.1 from 1.0.	4	2	330K	930K	3.07M
8 – Convert Selected Fire Protection Piping from Wet to Dry Pipe System	**The probability that operators fail to isolate a fire protection header leak was reduced to 0.1 from 1.0.**	**4**	**1**	**300K**	**860K**	**600K**

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
10 – Provide Procedural Guidance to use B.5.b Low Pressure Pump for Non-Security Events	**The probability that operators fail to align residual heat removal service water (RHRSW) for injection into the reactor pressure vessel (RPV) was reduced to 1.0E-02 from 1.0E-01.**	**1**	**1**	**200K**	**570K**	**100K**
15 – Alternate Design of Core Spray System (CSS) Suction Strainer to Mitigate Plugging	The probability that operators fail to locally open each of the service water valves was reduced to 8.36E-04 from 8.36E-03.	2	1	130K	360K	1.0M
16 – Use of Different Designs for Switchgear Room Cooling Fans	The probability that FANS AVH401 through DVH400 fail-to-start and fail-to-run was set to 0.	2	1	130K	370K	400K
17 – Replace a Supply Fan with a Different Design in Service Water Pump Room	**The probability that FANS AV503 through DV503 fail-to-start and fail-to-run was set to 0.**	**5**	**5**	**960K**	**2.7M**	**600K**
18 – Replace a Return Fan with a Different Design in Service Water Pump Room	**The probability that FANS AV504 through DV504 fail-to-start and fail-to-run was set to 0.**	**5**	**5**	**960K**	**2.7M**	**600K**
30 – Provide Procedural Guidance for Partial Transfer of Control Functions from Control Room to the Remote Shutdown Panel	**Reduce the fire CDF contribution from Fire Basic Events %IE-FIRE03, %IE-FIRE02, and %IE-FIRE01 by 90 percent.**	**NOT ESTIMATED**		**8.6M**	**24M**	**100K**
31 – Install Improved Fire Barriers in the Main Control Room (MCR) Control Cabinets Containing the Primary Main Steam Isolation Valve (MSIV) Control Circuits	Eliminate the fire CDF contribution from Fire Basic Event %IE-FIRE06.	NOT ESTIMATED		360K	1.0M	1.2M
32 – Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from Diesel Generator (DG) Rooms	**Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE28 by 90 percent.**	**NOT ESTIMATED**		**480K**	**1.4M**	**800K**

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
33 – Install Division II 480V AC Bus Cross-ties	Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE37 by 90 percent.	NOT ESTIMATED		450K	1.3M	1.32M
34 – Install Division I 480V AC Bus Cross-ties	Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE20 by 90 percent.	NOT ESTIMATED		430K	1.2M	1.32M
35 – Relocate, Minimize and/or Eliminate Electrical Heaters in Electrical Access Room	**Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE38 by 99 percent.**	**NOT ESTIMATED**		**410K[c]**	**1.2M[c]**	**270K**
36 – Provide Procedural Guidance for Loss of All 1E 120V AC Power	**Reduce the seismic CDF contribution from Seismic Basic Event %IE-SET36 by 50 percent.**	**NOT ESTIMATED**		**240K**	**680K**	**270K**
37 – Reinforce 1E 120V AC Distribution Panels	**Reduce the seismic CDF contribution from Seismic Basic Event %IE-SET36 by 90 percent.**	**NOT ESTIMATED**		**430K**	**1.2M**	**500K**
39 – Provide Procedural Guidance to Bypass Reactor Core Isolation Cooling (RCIC) Turbine Exhaust Pressure Trip	**As provided in response to an NRC staff RAI, modify fault tree to include a new operator action, having a failure probability of 1.0E-02, representing failure of the operator to defeat the HPCI/RCIC back pressure permissive .**	**10**	**<1**	**130K**	**380K**	**120K**
40 – Increase Reliability/Install Manual Bypass of Low Pressure (LP) Permissive	As provided in response to an NRC staff RAI, the probability of common cause mis-calibration of all ECCS pressure transmitters was reduced to 8.0E-06 from 8.0E-05.	1	1	210K	610K	620K
41[d] – Installation of Passive Hardened Containment Ventilation Pathway	A completely passive containment vent system requiring no operator actions is assumed.	15	30	6.2M	18M	>25M

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
42[d] – Installation of SACS Standby Diesel-Powered Pump	Reduce the probability of initiating event %IE-SACS to 1.16E-05 per year from 1.16E-04 per year.	2	1	270K	760K	6.2M

(a) SAMAs in bold are potentially cost-beneficial

(b) SAMA 5 was determined to be potentially cost beneficial based on revised assumptions, risk reduction, and baseline benefits provided in response to an NRC staff RAI (PSEG 2010a, PSEG 2010b). The baseline with uncertainty estimate was estimated by the NRC staff using information provided in the ER and in response to the RAI.

(c) The baseline benefit for SAMA 35 was provided by PSEG in response to an NRC staff RAI (PSEG 2010a). The baseline with uncertainty estimate was estimated by the NRC staff using information provided in the ER and in response to the RAI.

(d) SAMAs 41 and 42 were identified and evaluated in response to NRC staff RAIs (PSEG 2010a, PSEG 2010b).

(e) Using a factor of 2.84.

G.5 Cost Impacts of Candidate Plant Improvements

PSEG estimated the costs of implementing the 21 candidate SAMAs through the development of site-specific cost estimates. The cost estimates conservatively did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs for unforeseen difficulties (PSEG 2010a). The cost estimates provided in the ER did not account for inflation, which is considered another conservatism.

The NRC staff reviewed the bases for the applicant's cost estimates (presented in Table E.5-3 of Attachment E to the ER). For certain improvements, the NRC staff also compared the cost estimates to estimates developed elsewhere for similar improvements, including estimates developed as part of other licensees' analyses of SAMAs for operating reactors.

The ER stated that plant personnel developed HCGS-specific costs to implement each of the SAMAs. The NRC staff requested more information on the process PSEG used to develop the SAMA cost estimates (NRC 2010a). PSEG responded to the RAI by explaining that the cost estimates were developed in a series of meetings involving personnel responsible for development of the SAMA analysis and the two PSEG license renewal site leads who are engineering managers each having over 25 years of plant experience, including project management, operations, plant engineering, design engineering, procedure support, simulators, and training (PSEG 2010a). During these meetings, each SAMA was validated against the plant configuration, a budget-level estimate of its implementation cost was developed, and, in some instances, lower cost approaches that would achieve the same objective were developed. The SAMA implementation costs were then reviewed by the Design Engineering Manager for both technical and cost perspectives and revised accordingly. PSEG further explained that seven general cost categories were used in development of the budget-level cost estimates: engineering, material, installation, licensing, critical path impact, simulator modification, and procedures and training. Based on the use of personnel having significant nuclear plant engineering and operating experience, the NRC staff considers the process PSEG used to develop budget-level cost estimates reasonable.

The NRC staff requested additional clarification on the estimated cost of \$2.05M for implementation of SAMA 5, "Restore AC Power with Onsite Gas Turbine Generator," and on the implementation cost of \$270K for implementation of SAMA 36, "Provide Procedural Guidance for Loss of All 1E 120V AC Power," which are high for what are described as procedure changes and operator training (NRC 2010a). In response to an RAI, PSEG further described the SAMA 5 modification as providing the necessary equipment to connect a dedicated transformer at Salem Unit 3 to HCGS, which is significantly more costly than, and is in addition to, the procedure changes (PSEG 2010a). It was also explained that the SAMA 5 modification assumes that Salem Generating Station (SGS) SAMA 2 to install the dedicated transformer is already implemented and that SAMA 5 is a safety-related permanent plant modification. In response to a different RAI, PSEG explained that the SAMA 36 modification involves the development of a group of procedures, not just the revision of existing procedures or the development of a single procedure. In addition, there is a significant effort involved with determining a success path to achieve safe shutdown, to update the simulator to include all necessary components to implement the success path, to test the success path, and to implement the new procedures. Based on this additional information, the NRC staff considers the estimated cost to be reasonable and acceptable for purposes of the SAMA evaluation.

The NRC staff asked PSEG to justify the estimated cost of $100K for SAMA 10, "Provide Procedural Guidance to use B.5.b Low Pressure Pump for Non-Security Events," for what is described as including a new pump when $100K is the estimated cost of a procedure change used in the SAMA analysis (NRC 2010a). PSEG responded that the cost estimate for SAMA 10 assumes that an existing pump already installed at HCGS will be made available to implement this SAMA (PSEG 2010a). Based on this additional information, the NRC staff considers the estimated cost to be reasonable and acceptable for purposes of the SAMA evaluation.

In response to an RAI requesting a more detailed description of the changes associated with SAMA 16, "Use of Different Designs for Switchgear Room Cooling Fans," PSEG provided additional information detailing the cost estimate of this improvement (PSEG 2010a). The staff reviewed the cost estimate and found it to be reasonable, and generally consistent with estimates provided in support of other plants' analyses.

The NRC staff noted that SAMA 31, "Install Improved Fire Barriers in the Main Control Room (MCR) Control Cabinets Containing the Primary Main Steam Isolation Valve (MSIV) Control Circuits," is similar to SGS SAMAs 21 and 22 in that each involves installing fire barriers to prevent the propagation of a fire between cabinets and requested an explanation for why the estimated cost of $1.2M for SAMA 31 to modify one cabinet is similar to the estimated cost of $1.6M for SGS SAMA 22 to modify three Control Room consoles and is more than one-third of the $3.23M cost for SGS SAMA 21 to modify 48 Relay Room cabinets (NRC 2010a). PSEG responded that making the modifications to the SAMA 31 Control Room console, which is estimated to be $400K for materials and installation, is more complicated than making modifications to the SGS SAMA 21 Relay Room cabinets, which is estimated to be $35K to $70K for materials and maintenance (PSEG 2010a). Specifically, SAMA 31 requires making ventilation modifications due to the significant heat loads in addition to adding fire barrier materials. PSEG also explained that both SAMA 31 and SGS SAMA 22 assumed the same material and installation cost per console ($400K) and the same engineering cost ($800K) but that the engineering cost was evenly divided between the two units at SGS to arrive at a cost per unit. The NRC staff considers the basis for the differences in cost estimates reasonable.

The NRC staff noted that the estimated cost of $620K for SAMA 40, "Increase Reliability/Install Manual Bypass of Low Pressure (LP) Permissive," is significantly higher than the estimated cost of $250K for a similar improvement evaluated for the Duane Arnold nuclear power plant license renewal application (NRC 2010a). In response to the RAI, PSEG clarified that SAMA 40 involves the installation of six key-lock switches to bypass various low pressure submissives (PSEG 2010a). Key-lock switches are used rather than jumpers, as was assumed in the Duane Arnold application, because the benefit of this SAMA cannot be obtained otherwise due to the effort required to install six jumpers, which is a more time intensive action than the time required to operate key-lock switches. Based on this additional information, the NRC staff considers the estimated cost for HCGS to be reasonable and acceptable for purposes of the SAMA evaluation.

The NRC staff also noted that the estimated cost of $1.32M each for SAMA 33, "Install Division II 480V AC Bus Cross-ties," and SAMA 34, "Install Division I 480V AC Bus Cross-ties," is significantly higher than the estimated cost of $328K to $656K for a similar improvement evaluated for other nuclear power plant license renewal applications, i.e., Wolf Creek and Susquehanna (NRC 2010a). In response to the RAI, PSEG described these modifications as involving the installation of new tie-breakers and cables for the 480V AC bus cross-ties, having a material and installation cost of $400K (PSEG 2010a). The most significant cost was for engineering, which was estimated to be $800K due to the electrical load analysis required to support the cross-ties. Based on this additional information, the NRC staff considers the basis for the estimated cost to be reasonable.

The NRC staff concludes that the cost estimates provided by PSEG are sufficient and appropriate for use in the SAMA evaluation.

G.6 Cost-Benefit Comparison

PSEG's cost-benefit analysis and the NRC staff's review are described in the following sections.

G.6.1 PSEG's Evaluation

The methodology used by PSEG was based primarily on NRC's guidance for performing cost-benefit analysis, i.e., NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997a). The guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE, where

APE = present value of averted public exposure ($)
AOC = present value of averted offsite property damage costs ($)
AOE = present value of averted occupational exposure costs ($)
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($)

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and it is not considered cost-beneficial. PSEG's derivation of each of the associated costs is summarized below.

NUREG/BR-0058 has recently been revised to reflect the agency's policy on discount rates. Revision 4 of NUREG/BR-0058 states that two sets of estimates should be developed, one at 3 percent and one at 7 percent (NRC 2004). PSEG performed the SAMA analysis using the 3 percent discount rate and a sensitivity study using the 7 percent discount rate (PSEG 2009).

Averted Public Exposure (APE) Costs

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δperson-rem/year)
× monetary equivalent of unit dose ($2,000 per person-rem)
× present value conversion factor (15.04 based on a 20-year period with a 3-percent discount rate)

As stated in NUREG/BR-0184 (NRC 1997a), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk due to a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the renewal period) of the facility. Thus, it reflects the expected annual loss due to a single accident, the possibility that such an accident could occur at any time over the renewal period, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, which assumes elimination of all severe accidents, PSEG calculated an APE of approximately $688,000 for the 20-year license renewal period.

Averted Offsite Property Damage Costs (AOC)

The AOCs were calculated using the following formula:

AOC = Annual CDF reduction
x offsite economic costs associated with a severe accident (on a per-event basis)
x present value conversion factor.

This term represents the sum of the frequency-weighted offsite economic costs for each release category, as obtained for the Level 3 risk analysis. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an AOC of about $155,000 based on the Level 3 risk analysis. This results in a discounted value of approximately $2,332,000 for the 20-year license renewal period.

Averted Occupational Exposure (AOE) Costs

The AOE costs were calculated using the following formula:

AOE = Annual CDF reduction

× occupational exposure per core damage event
× monetary equivalent of unit dose
× present value conversion factor

PSEG derived the values for averted occupational exposure from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997a). Best estimate values provided for immediate occupational dose (3,300 person-rem) and long-term occupational dose (20,000 person-rem over a 10-year cleanup period) were used. The present value of these doses was calculated using the equations provided in the handbook in conjunction with a monetary equivalent of unit dose of $2,000 per person-rem, a real discount rate of 3 percent, and a time period of 20 years to represent the license renewal period. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an AOE of approximately $2,700 for the 20-year license renewal period (PSEG 2009).

Averted Onsite Costs

Averted onsite costs (AOSC) include averted cleanup and decontamination costs and averted power replacement costs. Repair and refurbishment costs are considered for recoverable accidents only and not for severe accidents. PSEG derived the values for AOSC based on information provided in Section 5.7.6 of NUREG/BR-0184, the regulatory analysis handbook (NRC 1997a).

PSEG divided this cost element into two parts – the onsite cleanup and decontamination cost, also commonly referred to as averted cleanup and decontamination costs (ACC), and the replacement power cost (RPC).

ACCs were calculated using the following formula:

ACC = Annual CDF reduction
x present value of cleanup costs per core damage event
× present value conversion factor

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in NUREG/BR-0184 to be $\$1.5 \times 10^9$ (undiscounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an ACC of approximately $87,000 for the 20-year license renewal period.

Long-term RPCs were calculated using the following formula:

RPC = Annual CDF reduction
x present value of replacement power for a single event

× factor to account for remaining service years for which replacement power is required
× reactor power scaling factor

PSEG based its calculations on a HCGS net output of 1287 megawatt electric (MWe) and scaled up from the 910 MWe reference plant in NUREG/BR-0184 (NRC 1997a). Therefore PSEG applied a power scaling factor of 1287/910 to determine the replacement power costs. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an RPC of approximately $35,000 and an AOSC of approximately $122,000 for the 20-year license renewal period.

Using the above equations, PSEG estimated the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS to be about $3.14M. Use of a multiplier of 6.3 to account for external events increases the value to $19.8M and represents the dollar value associated with completely eliminating all internal and external event severe accident risk for a single unit at HCGS, also referred to as the Maximum Averted Cost Risk (MACR).

PSEG's Results

If the implementation costs for a candidate SAMA exceeded the calculated benefit, the SAMA was considered not to be cost-beneficial. In the baseline analysis contained in the ER (using a 3 percent discount rate, and considering the impact of external events), PSEG identified nine potentially cost-beneficial SAMAs. PSEG performed additional analyses to evaluate the impact of parameter choices (alternative discount rates and variations in MACCS2 input parameters) and uncertainties on the results of the SAMA assessment and, as a result of this analysis, identified four additional potentially cost-beneficial SAMAs.

The potentially cost-beneficial SAMAs are:

- SAMA 1 – remove ADS Inhibit from Non-ATWS Emergency Operating Procedures
- SAMA 3 – Install Back-Up Air Compressor to Supply AOVs
- SAMA 4 – Provide Procedural Guidance to Cross-Tie RHR Trains
- SAMA 8 – Convert Selected Fire Protection Piping from Wet to Dry Pipe System
- SAMA 10 – Provide Procedural Guidance to Use B.5.b Low Pressure Pump for Non-Security Events
- SAMA 17 – Replace a Supply Fan with a Different Design in Service Water Pump Room
- SAMA 18 – Replace a Return Fan with a Different Design in Service Water Pump Room

- SAMA 30 – Provide Procedural Guidance for Partial Transfer of Control Functions from the Control Room to the Remote Shutdown Panel
- SAMA 32 – Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from DG Rooms
- SAMA 35 – Relocate, Minimize, and/or Eliminate Electrical Heaters in Electrical Access Room
- SAMA 36 – Provide Procedural Guidance for Loss of All 1E 120V AC Power
- SAMA 37 – Reinforce 1E 120V AC Distribution Panels
- SAMA 39 – Provide Procedural Guidance to Bypass RCIC Turbine Exhaust Pressure Trip

PSEG indicated that they plan to further evaluate these SAMAs for possible implementation using existing HCGS Plant Heal Committee processes (PSEG 2009).

The potentially cost-beneficial SAMAs, and PSEG's plans for further evaluation of these SAMAs, are discussed in detail in Section G.6.2.

G.6.2 Review of PSEG's Cost-Benefit Evaluation

The cost-benefit analysis performed by PSEG was based primarily on NUREG/BR-0184 (NRC 1997a) and discount rate guidelines in NUREG/BR-0058 (NRC 2004) and was executed consistent with this guidance.

SAMAs identified primarily on the basis of the internal events analysis could provide benefits in certain external events, in addition to their benefits in internal events. To account for the additional benefits in external events, PSEG multiplied the internal event benefits for each internal event SAMA by a factor of 6.3, which is the ratio of the total CDF from internal and external events to the internal event CDF. As discussed in Section G.2.2, this factor was based on a seismic CDF of 1.1×10^{-6} per year, plus a fire CDF of 1.7×10^{-5} per year, plus the screening values for high winds, external flooding, transportation, detritus, and chemical release events (1×10^{-6} per year for each). The external event CDF of 2.3×10^{-5} per year is thus 5.3 times the internal events release frequency CDF of 4.4×10^{-6} per year. The total CDF is thus 6.3 [$(2.3 \times 10^{-5} + 4.4 \times 10^{-6}) / 4.4 \times 10^{-6}$] times the internal events release frequency CDF (PSEG 2009). Seven SAMAs were determined to be cost-beneficial in PSEG's analysis (SAMAs 1, 3, 4, 10, 17, 18, and 39 as described above).

PSEG did not multiply the internal event benefits by the factor of 6.3 for eight SAMAs that specifically address fire and seismic risk (SAMAs 30, 31, 32, 33, 34, 35, 36, and 37).

Multiplying the internal event benefits by 6.3 for these SAMAs would not be appropriate because these SAMAs are specific to fire or seismic risks and would not have a corresponding benefit on the risk from internal events. Two of these SAMAs were found to be cost-beneficial in PSEG's analysis (SAMAs 30 and 35, as described above).

PSEG considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. In the ER, PSEG presents the results of an uncertainty analysis of the internal events CDF which indicates that the 95th percentile value is a factor of 2.84 times the point estimate CDF for HCGS. Since the two Phase I SAMAs that were screened based on qualitative criteria were screened due to one being subsumed into another SAMA or one having already been implemented at HCGS, a re-examination of the Phase I SAMAs based on the upper bound benefits was not necessary. PSEG considered the impact on the Phase II analysis if the estimated benefits were increased by a factor of 2.84 (in addition to the multiplier of 6.3 for external events). Four additional SAMAs became cost-beneficial in PSEG's analysis (SAMAs 8, 32, 36, and 37 as described above).

PSEG provided the results of additional sensitivity analyses in the ER, including use of a 7 percent discount rate and variations in MACCS2 input parameters. These analyses did not identify any additional potentially cost-beneficial SAMAs (PSEG 2009).

PSEG indicated that the 13 potentially cost-beneficial SAMAs (SAMAs 1, 3, 4, 8, 10, 17, 18, 30, 32, 35, 36, 37, and 39) will be considered for implementation through the established HCGS Plant Health Committee process (PSEG 2009).

As indicated in Section G.3.2, in response to NRC staff RAIs, PSEG considered additional plant improvements to address basic events for which no SAMAs had been identified in the ER. PSEG determined that of the plant improvements considered, two additional SAMAs warrant further consideration: 1) SAMA 41, "Installation of Passive Hardened Containment Ventilation Pathway," and 2) SAMA 42, "Installation of SACS Standby Diesel-Powered Pump." Each of these new SAMAs is included in Table G-6 and were evaluated as described above. PSEG's analysis determined that neither of these SAMA candidates was cost-beneficial in either the baseline analysis or the uncertainty analysis.

As indicated in Section G.2.2, PSEG determined that the external events multiplier would be 6.8 if the higher seismic CDF obtained using the LLNL hazard curves were used rather than the EPRI hazard curves. As discussed in Section G.3.2, PSEG then reviewed the Level 1 and Level 2 basic events down to an RRW of 1.005 to account for the revised external events multiplier of 6.8. In addition, since the maximum benefit of each seismic sequence increased as a result of using the LLNL hazard curves, PSEG reviewed two additional seismic sequences having a benefit equal to or greater than $100,000, the minimum expected SAMA implementation cost at HCGS. These reviews resulted in the identification and evaluation of five additional SAMAs, as summarized below:

- SAMA RAI 5.j-IE1, "Install a Key Lock Switch for Bypass of the Main Steam Isolation Valve (MSIV) Low Level Isolation Logic." PSEG estimated the implementation cost for this SAMA to be the same as SAMA 40, "Increase Reliability/Install Manual Bypass of Low Pressure (LP) Permissive," or $620K, which also involved installation of key lock bypass switches (PSEG 2010a). The maximum benefit was estimated to be $110K in the baseline analysis, and $300K after accounting for uncertainties, which assumed that the risk of the basic event addressed by this SAMA was completely eliminated. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that SAMA RAI 5.j-IE1 was not cost-beneficial.

- SAMA RAI 5p-1, "Install an Independent Boron Injection System." PSEG estimated the implementation cost of this SAMA to be $1.5M based on the estimate for a similar SAMA to install a redundant system evaluated in the Browns Ferry nuclear power plant license renewal application and the estimated cost to install an additional tank (PSEG 2010a). To estimate the risk reduction, PSEG modified the HCGS PRA model fault tree to include a new basic event, having a failure probability of 1.0E-03, representing failure of the redundant system. The benefit was estimated to be $390K in the baseline analysis, and $1.1M after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that SAMA RAI 5p-1 was not cost-beneficial.

- Reinforce 1E 125V DC distribution panels 1A/B/C/D-D-417. PSEG estimated the minimum implementation cost for this SAMA to be the same as SAMA 37, "Reinforce 1E 120V AC Distribution Panels," or $500K, but expects the cost to be higher because these panels have a much higher HCLPF value than the SAMA 37 120V AC panels (PSEG 2010a). To estimate the risk reduction, PSEG assumed that the contribution to risk from external events is approximately 5.8 times that from internal events (based on a revised seismic CDF of 3.58×10^{-6} per year using the LLNL hazard curves), that seismic events contribute 14 percent of this external events risk, and that 50 percent of the fire risk affected by the SAMA is eliminated. The benefit was estimated to be $155K in the baseline analysis, and $440K after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that this SAMA was not cost-beneficial.

- Reinforce 1E 120V AC distribution panels 1A/B/C/DJ482. PSEG estimated the implementation cost for this SAMA to be the same as SAMA 37, or $500K, which also addresses 120V AC panels (PSEG 2010a). To estimate the risk reduction, PSEG assumed that the contribution to risk from external events is approximately 5.8 times that from internal events (based on a revised seismic CDF of 3.58×10^{-6} per year using the LLNL hazard curves), that seismic events contribute 14 percent of this external events risk, and that all of the seismic risk affected by the SAMA is eliminated. The benefit was estimated to be $110K in the baseline analysis, and $320K after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that this SAMA was not cost-beneficial.

- Reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating. This SAMA assumes that 1) SAMA 37 is implemented, 2) the HCLPF values for the 120V AC panels are further increased to 1 g as a result of the implementation, 3) the above SAMA to reinforce the 125V DC panels is implemented, and 4) the HCLPF values for the panels are increased from the current 0.57g to 1.0g as a result of the implementation (PSEG 2010b). SAMA 37 originally was assumed to reduce the risk of seismic basic event %IE-SET36, "seismic-induced equipment damage state SET-36 (impacts – 120V PNL481," by 90 percent while the proposed SAMA to reinforce the 125V DC panels, by itself was originally assumed to reduce the risk of seismic basic event %IE-SET37, seismic-induced equipment damage state (impacts – 125V)," by 50 percent. The synergistic benefit of this new proposed SAMA to reinforce the 120V AC panels to a HCLPF value of 1.0g is assumed to be the sum of the benefit to eliminate the remaining 10 percent of the risk of event %IE-SET36 ($176K) and the remaining 50 percent of the risk of event %IE-SET37 ($155K), for a total benefit of $330K in the baseline analysis, and $940K after accounting for uncertainties. PSEG estimated the implementation cost for this SAMA to be $900K, which assumes the panels can be modified and not have to be replaced. Since the estimated benefit is greater than the implementation cost, PSEG determined that this proposed SAMA was potentially cost-beneficial. PSEG stated that this proposed SAMA will be considered for implementation through the established HCGS Plant Health Committee process.

  The NRC staff notes that SAMA 37 was determined to be cost-beneficial and will be considered by PSEG for implementation through the established HCGS Plant Health Committee process. PSEG concluded, however, that the above originally proposed SAMA to reinforce the 125V DC panels was, by itself, not cost-beneficial, yet it was assumed to be implemented in the evaluation of this new proposed combined SAMA. Because the risk reduction from this new proposed SAMA to reinforce the 120V AC panels to a HCLPF value of 1.0g cannot be obtained without implementation of the proposed SAMA to reinforce the 125V DC panels, the NRC staff concludes that both SAMAs (SAMA 37 and the combined SAMA of reinforcing both the 120 VAC and 125 VDC panels) should be considered for implementation.

As indicated in Section G.3.2, two plant improvements were identified in the ER but not included in the SAMA evaluation because they were higher cost than the SAMA selected for evaluation. The NRC staff noted however that the two improvements could have larger benefits than the SAMAs evaluated because they could be more effective or could mitigate additional events (PSEG 2010a). In response to the RAIs, PSEG evaluated the two improvements, as summarized below:

- Replace the normally open floor and equipment drain MOVs with fail-closed AOVs. PSEG estimated the implementation cost of this SAMA to be $2.05M, which is half the estimate for a similar SAMA to replace cooling water system MOVs, which are larger than drain MOVs, with fail-closed AOVs evaluated in the TMI-1 nuclear power plant license renewal application (PSEG 2010a). To estimate the risk reduction, PSEG assumed that the entire release frequency associated with basic event CIS-DRAN-L2-OPEN, "valves open automatically for drainage normally open," after adjustment to account for existing procedures that are not credited, was eliminated. The benefit, assuming an external multiplier of 6.8, was estimated to be $710K in the baseline analysis, and $2.0M after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded the proposed improvement was not cost-beneficial.

- Auto align 480V AC portable station generator. For HCGS, this improvement is described as requiring permanent installation of an existing portable generator and adding the logic to perform the auto start and load function. PSEG estimated the implementation cost of this SAMA to be at least $1.0M based on an estimate of $1.0M from the Shearon Harris nuclear power plant license renewal application to permanently install a 480V AC generator and pump and an estimate of $3.1M from the TMI-1 nuclear power plant license renewal application to automate the start and load of an existing, permanently installed 4KV AC generator (PSEG 2010a, PSEG 2010b). To estimate the risk reduction, PSEG set the failure probabilities of existing operator actions to align the portable generator, and associated joint human error probabilities, to zero. The benefit, assuming an external multiplier of 6.8, was estimated to be $210K in the baseline analysis, and $600K after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded the proposed improvement was not cost-beneficial.

As indicated in Section G.3.2, for certain SAMAs considered in the ER, there may be alternatives that could achieve much of the risk reduction at a lower cost. The NRC staff asked the applicant to evaluate additional lower cost alternatives to the SAMAs considered in the ER, as summarized below (NRC 2010a):

- Establishing procedures for opening doors and/or using portable fans for sequences involving room cooling failures. In response to the NRC staff RAI, PSEG stated that HCGS already has procedures to implement the suggested alternative on loss of normal Switchgear Room HVAC and that this event is credited in the PRA model (PSEG 2010a). However, PSEG did provide an evaluation to implement the suggested alternative in the Service Water Pump Room, which is considered a more practical and cost effective change than SAMA 17, "Replace a Supply Fan with a Different Design in Service Water Pump Room," and SAMA 18, "Replace a Return Fan with a Different Design in Service Water Pump Room," which involve permanent hardware modifications. The cost of implementing an alternate room cooling strategy for this room, identified as SAMA RAI 7.a-1, was estimated to be $150K. The baseline benefit was assumed to be the sum of the estimated benefits for SAMAs 17 and 18, or $1.9M. Accounting for the revised multiplier of 6.8 and uncertainties increases the benefit to $5.9M. Since the estimated benefit is greater than the implementation cost, PSEG determined that SAMA RAI 7.a-1 was potentially cost-beneficial. PSEG also stated that this SAMA will be further evaluated in parallel with cost-beneficial SAMAs 17 and 18 since there may be some benefit associated with the permanent hardware modifications considered in these SAMAs.

- Extending the procedure for using the B.5.b low pressure pump for non-security events to include all applicable scenarios, not just SBOs. In response to the NRC staff RAI, PSEG stated that the estimated benefit for SAMA 10, "Provide Procedural Guidance to use B.5.b Low Pressure Pump for Non-Security Events," already includes the risk reduction for all applicable scenarios (PSEG 2010a). The NRC staff concludes that the suggested alternative has already been addressed.

- Utilizing a portable independently powered pump to inject into containment. In response to the NRC staff RAI, PSEG explained that the HCGS PRA model already credits use of the diesel fire pump to inject into the RPV and containment and that the addition of another independently powered pump to provide injection would have limited benefit (PSEG 2010a). PSEG further noted that SAMA 10 already evaluated aligning the B.5.b low pressure pump with RHRSW to provide al alternate source of injection. The NRC staff concludes that the suggested alternative has already been addressed.

As indicated in Section G.4, the NRC staff questioned PSEG on the risk reduction potential for certain SAMAs (NRC 2010a, NRC 2010b), as summarized below.

- For SAMA 5, "Restore AC Power with Onsite Gas Turbine Generator," PSEG provided a revised estimate of the benefit that included credit for the additional capability for mitigating a more complete set of loss of offsite power initiators that is consistent with the hardware changes proposed (PSEG 2010a, PSEG 2010b). This SAMA was determined to be potentially cost-beneficial in PSEG's revised analysis. PSEG stated that SAMA 5 will be considered for implementation through the established HCGS Plant Health Committee process.

- For SAMA 35, "Relocate, Minimize and/or Eliminate Electrical Heaters in Electrical Access Room", PSEG provided a revised estimate of the benefit assuming 99 percent of the fire risk affected by the SAMA was eliminated (PSEG 2010a). This SAMA was determined to remain cost-beneficial in PSEG's revised analysis.

The NRC staff notes that the 13 cost-beneficial SAMAs (SAMAs 1, 3, 4, 8, 10, 17, 18, 30, 32, 35, 36, 37, and 39) identified in PSEG's original baseline and uncertainty analysis, and the three SAMAs and plant improvements determined to be cost-beneficial in response to NRC staff RAIs ("establishing procedures for opening doors and/or using portable fans for sequences involving Service Water Pump Room cooling failures," SAMA 5, and "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating"), are included within the set of SAMAs that PSEG plans to further consider for implementation through the established Salem Plant Health Committee (PHC) process. The NRC staff suggests that the proposed SAMA to "reinforce the 120V DC panels" also be considered for implementation since it must be implemented to obtain the risk reduction benefits of the SAMA to "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating."

In response to an NRC staff RAI, PSEG described the PHC as being chaired by the Plant Manager and includes as members the Plant Engineering Manager and the Directors of Operations, Engineering, Maintenance, and Work Management (PSEG 2010a). The PHC is chartered with reviewing issues that require special plant management attention to ensure effective resolution and, with respect to each of the potentially cost-beneficial SAMAs, will decide on one of the following courses of actions: 1) approve for implementation, 2) conditionally approved for implementation pending the results of requested evaluations, 3) not approved for implementation, or 4) table until additional information needed to make a final decision is provided to the PHC. Additional information requested may include 1) making corrections to the original SAMA analysis, 2) examining an alternate solution, 3) performing sensitivity studies to determine the effect of implementing a sub-set of SAMAs, already approved SAMAs, or already approved non-SAMA design changes on the SAMA, or 4) coordinating the SAMA with related Mitigating System Performance Index (MSPI) margin recovery activities. If approved or conditionally approved for implementation, the SAMA will be ranked with respect to priority and assigned target years for implementation.

The NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the other SAMAs evaluated would be higher than the associated benefits.

G.7 Conclusions

PSEG compiled a list of 23 SAMAs based on a review of: the most significant basic events from the plant-specific PRA and insights from the HCGS PRA group, insights from the plant-specific IPE and IPEEE, Phase II SAMAs from license renewal applications for other plants, and the generic SAMA candidates from NEI 05-01. A qualitative screening removed SAMA candidates that: (1) are not applicable to HCGS due to design differences, (2) have already been implemented at HCGS, (3) would achieve results that have already been achieved at HCGS by other means, and (4) have estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at HCGS. Based on this screening, 2 SAMAs were eliminated leaving 21 candidate SAMAs for evaluation. Nine additional SAMA candidates or plant improvements were identified and evaluated in response to NRC staff RAIs.

For the remaining 21 SAMA candidates, a more detailed design and cost estimate were developed as shown in Table G-6. The cost-benefit analyses in the ER and RAI response showed that 9 of the SAMA candidates were potentially cost-beneficial in the baseline analysis (Phase II SAMAs 1, 3, 4, 10, 17, 18, 30, 35, and 39). PSEG performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. Four additional SAMA candidates (SAMAs 8, 32, 36, and 37) were identified as potentially cost-beneficial in the ER. In response to an NRC staff RAI regarding the assumptions used to estimate the risk reduction potential of certain SAMAs, PSEG identified one additional potentially cost-beneficial SAMA (SAMA 5). In response to NRC staff RAIs regarding the seismic CDF and potential lower cost alternatives, PSEG further identified "establishing procedures for opening doors and/or using portable fans for sequences involving Service Water Pump Room cooling failures" and "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating" as being potentially cost-beneficial enhancements. PSEG has indicated that all 14 potentially cost-beneficial SAMAs, as well as the enhancements "establishing procedures for opening doors and/or using portable fans for sequences involving Service Water Pump Room cooling failures" and "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating," will be considered for implementation through the established HCGS Plant Health Committee process. In addition, it is suggested that the plant improvement to "reinforce the 120V DC panels" be included in the set of SAMAs to be considered for implementation since it must be implemented to obtain the risk reduction benefits of the plant improvement to "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating."

The NRC staff reviewed the PSEG analysis and concludes that the methods used and the implementation of those methods was sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by PSEG are reasonable and sufficient for the license renewal submittal. Although the treatment of SAMAs for external events was somewhat limited, the likelihood of there being cost-beneficial enhancements in this area was minimized by improvements that have been realized as a result of the IPEEE process, and inclusion of a multiplier to account for external events.

The NRC staff concurs with PSEG's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of the identified, potentially cost-beneficial SAMAs. Given the potential for cost-beneficial risk reduction, the NRC staff agrees that further evaluation of these SAMAs by PSEG is warranted. However, these SAMAs do not relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of license renewal pursuant to Title 10 of the *Code of Federal Regulations*, Part 54.

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