Appendix F

Generic Environmental Impact Statement Environmental Issues Not Applicable to Vermont Yankee Nuclear Power Station

Appendix F

Generic Environmental Impact Statement Environmental Issues Not Applicable to Vermont Yankee Nuclear Power Station

Table F-1 lists those environmental issues listed in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996, 1999)[a] and Title 10, Part 51, of the *Code of Federal Regulations* (10 CFR Part 51), Subpart A, Appendix B, Table B-1, that are not applicable to Vermont Yankee Nuclear Power Station (VYNPS) because of plant or site characteristics.

Table F-1. GEIS Environmental Issues Not Applicable to VYNPS

ISSUE–10 CFR Part 51, Subpart A, Appendix B, Table B-1	Category	GEIS Sections	Comment
SURFACE-WATER QUALITY, HYDROLOGY, AND USE (FOR ALL PLANTS)			
Altered salinity gradients	1	4.2.1.2.2	VYNPS does not discharge to an estuary.
Altered thermal stratification of lakes	1	4.2.1.2.2; 4.4.2.2	VYNPS does not use surface water from lakes.
GROUNDWATER USE AND QUALITY			
Groundwater-use conflicts (potable and service water, and dewatering; plants that use >100 gpm)	2	4.8.1.1; 4.8.2.1	VYNPS does not use >100 gpm of groundwater.
Groundwater-use conflicts (Ranney wells)	2	4.8.1.4	VYNPS does not use Ranney wells.
Groundwater-quality degradation (Ranney wells)	1	4.8.2.2	VYNPS does not use Ranney wells.
Groundwater-quality degradation (saltwater intrusion)	1	4.8.2.1	VYNPS uses <100 gpm of groundwater and is not located near a saltwater body.
Groundwater-quality degradation (cooling ponds in salt marshes)	1	4.8.3	VYNPS does not use a cooling pond.

(a) The GEIS was originally issued in 1996. Addendum 1 to the GEIS was issued in 1999. Hereafter, all references to the "GEIS" include the GEIS and its Addendum 1.

Table F-1. (contd)

ISSUE–10 CFR Part 51, Subpart A, Appendix B, Table B-1	Category	GEIS Sections	Comment
Groundwater-quality degradation (cooling ponds at inland sites)	2	4.8.3	VYNPS does not use a cooling pond.
TERRESTRIAL RESOURCES			
Bird collisions with cooling towers	1	4.3.5.2	VYNPS does not use natural draft towers.
Cooling pond impacts on terrestrial resources	1	4.4.4	VYNPS does not use a cooling pond.

F.1 References

10 CFR Part 51. *Code of Federal Regulations*, Title 10, *Energy*, Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions."

U.S. Nuclear Regulatory Commission (NRC). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437, Vols. 1 and 2, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1999. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Main Report*, "Section 6.3 – Transportation, Table 9.1, Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Final Report." NUREG-1437, Vol. 1, Addendum 1, Washington, D.C.

Appendix G

NRC Staff Evaluation of Severe Accident Mitigation Alternatives (SAMAs) for Vermont Yankee Nuclear Power Station

Appendix G

NRC Staff Evaluation of Severe Accident Mitigation Alternatives (SAMAs) for Vermont Yankee Nuclear Power Station

G.1 Introduction

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy) submitted an assessment of severe accident mitigation alternatives (SAMAs) for Vermont Yankee Nuclear Power Station (VYNPS) as part of the environmental report (ER) (Entergy 2006a). This assessment was based on the most recent VYNPS probabilistic safety assessment (PSA) available at that time (Model VY04R1), a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 (MACCS2) computer code, and insights from the VYNPS individual plant examination (IPE) (VYNPC 1993) and individual plant examination of external events (IPEEE) (VYNPC 1998). In identifying and evaluating potential SAMAs, Entergy considered SAMAs that addressed the major contributors to core damage frequency (CDF) and population dose at VYNPS, as well as SAMA candidates for other operating plants which have submitted license renewal applications. Entergy identified 302 potential SAMA candidates. This list was reduced to 66 unique SAMA candidates by eliminating SAMAs that: are not applicable to VYNPS due to design differences, have already been implemented at VYNPS, or are similar in nature and could be combined with another SAMA candidate. Entergy 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 Entergy by letter dated June 1, 2006 (NRC 2006a). Key questions concerned: findings of the Boiling Water Reactor Owners Group (BWROG) and the independent assessment team reviews of the VYNPS PSA; the approach used to assign source terms for each release category as a part of the Level 2 analysis; justification for the multiplier used for external events; further information on several specific candidate SAMAs and low cost alternatives; and details for several of the cost estimates provided. Entergy submitted additional information by letters dated August 1, 2006, September 19, 2006, October 20, 2006 and November 6, 2006 (Entergy 2006b, Entergy 2006c, Entergy 2006d, Entergy 2006e). In response to the RAIs, Entergy provided: information regarding the findings of the BWROG peer review; a discussion of the process for assigning severe accident source terms for the Level 2 analysis; additional information regarding several specific SAMAs; and additional information pertaining to the cost estimates. Additionally, Entergy provided two attachments to the RAI responses, containing information on a later version of the PSA (version VY05R0) and a revised assessment of the SAMA benefits based on this later version of the PSA. This revised assessment utilizes a modified multiplier to account for external events exclusive of uncertainties, and a modified core inventory to account for plant-specific burn-up and enrichment. Entergy's responses addressed the NRC staff's concerns.

An assessment of SAMAs for VYNPS is presented below.

G.2 Estimate of Risk for Vermont Yankee Nuclear Power Station

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

G.2.1 Entergy's Risk Estimates

Two distinct analyses are combined to form the basis for the risk estimates used in the SAMA analysis: (1) the VYNPS Level 1 and 2 PSA model, which is an updated version of the IPE (VYNPC 1993) that accounts for the Extended Power Uprate (EPU) conditions, and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PSA model) developed specifically for the SAMA analysis. The ER (Entergy 2006a) included a SAMA analysis based on PSA version VY04R1. Subsequently, the SAMA analysis was revised based on PSA version VY05R0, and submitted as part of Entergy's RAI response (Entergy 2006c). The scope of the VYNPS PSA does not include external events.

The baseline CDF for the purpose of the SAMA evaluation is approximately 8.0 x 10^{-6} per year. The CDF is based on version VY05R0 of the PSA for internally-initiated events. Entergy did not include the contribution from external events within the VYNPS risk estimates; however, it did account for the potential risk reduction benefits associated with external events by effectively multiplying the estimated benefits for internal events by a factor of 3.33[(a)]. 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. The results from the earlier PSA model (VY04R1) are also provided for information. As shown in this table, events initiated by loss of offsite power, internal flooding, transients without the power conversion system, and loss of an AC bus are the dominant contributors to CDF. Although not separately reported, station blackout (SBO) sequences contribute 2.3 x 10^{-6} per year (about 29 percent of the total

(a) In the ER, Entergy bounded the combined impact of external events and uncertainties by applying a multiplier of 10 to the estimated SAMA benefits for internal events. In response to an RAI, Entergy revised the analysis to include a multiplier of 3.33 to account for potential SAMA benefits in both internal and external events, and provided a separate accounting of uncertainties.

Table G-1. VYNPS Core Damage Frequency

PSA Model	VY04R1		VY05R0	
Initiating Event	**CDF* (Per Year)**	**% Contribution to CDF**	**CDF[(a)] (Per Year)**	**% Contribution to CDF**
Loss of offsite power	7.2×10^{-7}	14	2.8×10^{-6}	35
Internal Flooding	$1.5 \text{ X } 10^{-6}$	29	1.4×10^{-6}	17
Transients without power conversion system	8.2×10^{-7}	16	8.4×10^{-7}	11
Loss of AC Bus 3	4.0×10^{-7}	8	7.9×10^{-7}	10
Loss of AC Bus 4	3.5×10^{-7}	7	7.3×10^{-7}	9
Loss of DC Bus 2	2.5×10^{-7}	5	2.8×10^{-7}	4
Loss of DC Bus 1	2.6×10^{-7}	5	2.8×10^{-7}	3
Inadvertently opened relief valve	2.7×10^{-7}	5	2.7×10^{-7}	3
Reactor trip	1.4×10^{-7}	3	1.7×10^{-7}	2
Anticipated Transient Without Scram	1.4×10^{-7}	3	1.5×10^{-7}	2
Loss of Coolant Accidents	3.7×10^{-8}	1	7.3×10^{-8}	1
Stuck-open relief valve	6.9×10^{-8}	1	6.5×10^{-8}	1
Total loss of service water	5.0×10^{-8}	1	5.2×10^{-8}	1
Interfacing System LOCA	1.6×10^{-8}	<1	3.9×10^{-8}	<1
LOCA outside containment	3.7×10^{-8}	1	3.4×10^{-8}	<1
Total CDF	$\mathbf{5.0 \times 10^{-6}}$	**100**	$\mathbf{8.0 \times 10^{-6}}$	**100**

(a) Point Estimate.

internal events CDF) (Entergy 2006c), while anticipated transient without scram (ATWS) sequences contribute 1.5×10^{-7} per year to CDF (about 2 percent of the total internal events CDF). With the Loss of Offsite Power (LOOP) initiating event contributing 2.8×10^{-6} per year to the CDF, the percentage of LOOP events resulting in SBO is high. This is because the dominant LOOP initiator involves a regional blackout due to severe weather conditions (Entergy 2006d).

The Level 2 VYNPS PSA model that forms the basis for the SAMA evaluation represents an updated version of the original IPE Level 2 model. The current Level 2 model utilizes a single containment event tree (CET), containing both phenomenological and systemic events, that is directly linked with the Level 1 models. CET nodes are evaluated using supporting fault trees and logic rules. Plant Damage States (also called core damage sequence functional classes) were defined for the purposes of summarizing and reporting the results of the Level 1 and Level 2 analyses.

The result of the Level 2 PSA is a set of 14 release categories with their respective frequency and release characteristics. The results of this analysis for VYNPS are provided in Table RAI.2.b of the RAI responses (Entergy 2006c). The frequency of each release category was obtained from the quantification of the linked Level 1 - Level 2 models and is the sum of the frequency of the individual accident progression CET endpoints binned into the release category. The release characteristics for each release category were obtained by frequency-weighting the release characteristics for each CET endpoint contributing to the release category (Entergy 2006c).

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 an 80-kilometer (50-mile) radius) for the year 2032, emergency response evacuation modeling, and economic data. The core radionuclide inventory is derived from an ORIGEN calculation assuming a 4.65 percent enrichment and average burn-up (Entergy 2006b). 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 1997b).

In the revised SAMA analysis (Entergy 2006c), Entergy estimated the dose to the population within 80 kilometers (50 miles) of the VYNPS site to be approximately 0.151 person-sievert (Sv) (15.1 person-rem) per year. The breakdown of the total population dose by containment release mode is summarized in Table G-2. Containment failures within the early time frame (less than 6 hours following accident initiation) dominate the contributions to the population dose risk at VYNPS.

G.2.2 Review of Entergy's Risk Estimates

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

- The Level 1 and Level 2 risk models of the 1993 IPE submittal (VYNPC 1993), and the external events analyses of the 1998 IPEEE submittal (VYNPC 1998),

- The major modifications to the IPE model that have been incorporated in the VYNPS PSA, and

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

Containment Release Mode	Population Dose (Person-Rem[a] Per Year)	% Contribution
Early Containment Failure	12.8	85
Late Containment Failure	2.1	14
Containment Bypass	0.2	1
Intermediate Containment Failure	< 0.1	< 1
Intact Containment	negligible	negligible
Total	**15.1**	**100**

(a) One person-Rem = 0.01 person-Sv.

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

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

The NRC staff's review of the VYNPS IPE is described in an NRC report dated February 9, 1996 (NRC 1996). Based on a review of the IPE submittal, the NRC staff concluded that the IPE submittal met the intent of Generic Letter (GL) 88-20; that is, the licensee's IPE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities. It was noted that internal flooding and weather related LOOP initiators were included in the IPEEE, but not in the IPE. The current internal-event PSA, however, includes both internal flooding and weather-related LOOP initiators. No severe accident vulnerabilities associated with either core damage or poor containment performance were identified in the IPE.

While no vulnerabilities were identified in the IPE and no hardware modifications were proposed as a result of the IPE, several plant improvements were identified and implemented prior to and in conjunction with the IPE. These improvements included: replacement of uninterrupted power supply for the low pressure coolant injection system injection valves, improvement of the safety relief valve and main steam isolation valve (MSIV) pneumatic components, replacement of instrument air compressors and upgrade of the residual heat removal service water (RHRSW) system (NRC 1996).

The VYNPS IPEEE analysis of internal flooding yielded a CDF of 9.0×10^{-6} per year. The NRC staff IPEEE SER (NRC 2001) concluded, with respect to the internal flooding, that while the analysis process is capable of identifying the most likely severe accidents, insufficient information was provided and that this weakness may inhibit its use in other regulatory applications. The internal flooding analysis has been subsequently updated, and the current CDF is 1.4 x 10^{-6} per year. The model has also been incorporated within the scope of the internal-events PSA. The internal flooding model is discussed further in Section G.3.2.

The VYNPS IPEEE listed 14 opportunities for improvements with respect to internal flooding. In response to an RAI, Entergy provided the status of these 14 improvements (Entergy 2006b). Ten have been implemented and credited in the current flooding risk analysis or were shown by analysis not to be required. The remaining four were judged to mitigate non-credible events or not have a significant impact on risk. In response to a staff RAI, Entergy described a review of the revised flooding risk analysis performed in 2002 to identify modifications that would further reduce the flooding risk (Entergy 2006e). A modification to provide spray shielding in two areas was identified and included in the current analysis as a candidate SAMA. No other modifications, short of major structural or relocation changes were identified. The NRC staff concludes that the opportunity for internal flood-related SAMAs has been adequately explored and that it is unlikely that there are any additional potentially cost-beneficial, internal flood-related SAMA candidates.

There have been numerous revisions to the IPE model since the 1993 IPE submittal. A comparison of internal events CDF between the 1993 IPE and the current PSA model (version VY05R0) indicates an increase of approximately 3.7 x 10^{-6} per year (from 4.3 x 10^{-6} per year to 8.0 x 10^{-6} per year). However, as indicated above, the 1993 IPE did not include internal flooding, which originally had an estimated CDF of 9.0 x 10^{-6} per year. If this is added to the 1993 IPE value for internal events, the resulting CDF is 1.3 x 10^{-5} per year. This indicates a reduction in the CDF between the 1993 IPE and the current PSA model of 5 x 10^{-6} per year (from 1.3 x 10^{-5} per year to 8.0 x 10^{-6} per year).

A comparison of the contributors to the total CDF indicates that some have increased while others have decreased from the IPE. The most notable changes are in the LOOP, which has increased from approximately 8.6 x 10^{-7} per year to 2.8 x 10^{-6} per year, internal flooding, which decreased from approximately 9.0 x 10^{-6} per year (from the IPEEE) to 1.4 x 10^{-6} per year and ATWS, which decreased from approximately 8 x 10^{-7} per year to 1.5 x 10^{-7} per year. A summary listing of those changes that resulted in the greatest impact on the internal events CDF made in the various revisions of the PSA was provided in response to a staff request for additional information and is summarized in Table G-3 (Entergy 2006c).

The CDF value from the 1993 IPE (1.3 x 10^{-5} per year, including the contribution from internal flooding events) is near the average of the CDF values reported in the IPEs for boiling-water reactor (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 x 10^{-8} to 8 x 10^{-5} per year, with an average CDF for the group of 2 x 10^{-5} per year (NRC 1997a). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes.

Table G-3. VYNPS PSA Historical Summary

PSA Version	Summary of Changes from Prior Model[a]	CDF per Year
1993	IPE Submittal - no internal flooding (With 1998 IPEEE internal flooding of 9.0×10^{-6} added)	4.3×10^{-6} (1.3×10^{-5})
1998 Model Update (VY118)	Reviewed by BWROG in 2000 (With 1998 IPEEE internal flooding of 9.0×10^{-6} added) - corrected modeling limitations found in IPE - incorporated impact of three design changes (ATWS rule instrumentation, normal position of LPCI/RHR minimum flow valve, and standby position of torus vent valve)	4.9×10^{-6} (1.4×10^{-5})
VY00R0	- Integrated individual models (transients, LOCAs, internal flooding, ISLOCA, LOCA outside containment and Level 2) into single model - updated component failure database	1.8×10^{-5}
VY02R0	- Incorporated major design changes (addition of fourth battery charger, replacement of 24VDC batteries with 125VDC to 24VDC converter, and containment nitrogen system model revised to reflect new piping and nitrogen supply) - Updated failure rate and unavailability data - Updated initiating event frequencies - Updated internal flooding model to include: two separate initiators for SW line break in torus room, revised human error probabilities, and additional credit for CRD system	4.3×10^{-6}
VY02R6	- Revised non-recovery factors for loss of service water and loss of offsite power - Revised model to have separate initiators for SORV and IORV - Removed credit for use of CRD for injection early in event sequences	7.8×10^{-6}
VY04R1	- Revised model to account for effects associated with Extended Power Uprate[b] - Revised treatment of SW recovery to be based on system failure modes - Revised flooding analysis of SW line break at elevation 280' - Updated loss of vital DC bus initiating event frequency - Updated reactor protection system fault tree model	5.0×10^{-6}
VY05R0	- Increased mission time for emergency diesel generators from 8 to 24 hours - Updated frequency of loss of offsite power (LOOP) initiating event - Added LOOP due to severe weather - Revised model to include credit for use of John Deere diesel generator as an alternate power supply for the station battery chargers - Reevaluated human error associated with use of diesel driven fire pump - Added operator action to model the potential that the operator fails to adequately control the torus vent, leading to a net positive suction head (NPSH) loss and ECCS pump failure	8.0×10^{-6}

(a) Summary of changes includes the key changes made to previous model revisions not specifically listed in this table.
(b) A sensitivity study associated with the EPU application indicated that the EPU increased the CDF by 3.3×10^{-7} per year (Entergy 2003).

The current internal events CDF results for VYNPS (8.0×10^{-6} per year) are comparable to or somewhat lower than that for other plants of similar vintage and characteristics.

The NRC staff considered the peer reviews performed for the VYNPS PSA, and the potential impact of the review findings on the SAMA evaluation. In the ER and in a response to a staff RAI (Entergy 2006a, 2006b), Entergy described the peer review by the BWROG of the 1998 model (Model VY118) conducted in September of 2000. Entergy also provided a list of strengths and weaknesses identified by the peer review, and a list of ten areas for improvement along with their resolution. The BWROG review concluded that the VYNPS PSA can be effectively used to support applications involving risk significance determinations supported by deterministic analysis, once the significant Facts and Observations (F&Os) are addressed. In response to the NRC staff's request for additional information concerning the application for extended power uprate (Entergy 2004), Entergy indicated that a total of 104 F&Os were identified during the BWROG peer review, and provided a listing of the single "Category A" and the 51 "Category B" F&Os, along with their resolutions. The NRC staff reviewed this material and concluded that the VYNPS PSA has sufficient scope, level of detail and technical adequacy to support the risk evaluation of the proposed EPU (NRC 2005). In the context of the SAMA application, Entergy stated that all significant F&Os (i.e., A and B priority) have been resolved and that appropriate modeling changes have been implemented in the PSA version used to support SAMA analysis.

The internal flooding analysis performed for the IPEEE was included within the BWROG peer review. Entergy indicated that internal flooding was cited in the review as a strength and that there were no recommended areas for improvement associated with internal flooding. In response to an RAI (Entergy 2006b), Entergy described the significant changes subsequently made in the internal flooding analysis to support the significant reduction in CDF due to internal flooding.

Given that the VYNPS internal events PSA model has been peer-reviewed and the peer review findings were either addressed or judged to have no adverse impact on the SAMA evaluation, and that Entergy has satisfactorily addressed NRC staff questions regarding the PSA, the NRC staff concludes that the internal events Level 1 PSA model is of sufficient quality to support the SAMA evaluation.

As indicated above, the current VYNPS PSA does not include external events. In the absence of such an analysis, Entergy used the VYNPS IPEEE to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences, as discussed below.

The VYNPS IPEEE was submitted in June 1998 (VYNPC 1998), in response to Supplement 4 of GL 88-20. This submittal included internal flooding, as well as the usual external events (seismic, fire and other external events). While no fundamental weaknesses or vulnerabilities to severe accident risk in regard to the external events were identified, a listing of improvement opportunities was developed. Improvements related to internal flooding were discussed above. Additional improvements for seismic, fire, high winds and other external events are discussed below. In a letter dated March 22, 2001, the NRC staff concluded that the submittals met the intent of Supplement 4 to GL 88-20, and that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities (NRC 2001).

The VYNPS IPEEE uses a focused scope Electric Power Research Institute (EPRI) seismic margins analysis. This method is qualitative and does not provide numerical estimates of the CDF contributions from seismic initiators (EPRI 1991). The seismic IPEEE identified a number of outliers of items within the scope of the Unresolved Safety Issue (USI) A-46 program. Resolution of these outliers was accomplished in the context of USI A-46. Given the satisfactory resolution of these outliers, VYNPS found that, based on the EPRI assessment methodology, all high confidence low probability of failure (HCLPF) values were greater than the 0.3 g review level earthquake used in the IPEEE except for the condensate storage tank (CST) with a HCLPF value of 0.25 g and the Diesel Fuel Oil Storage Tank with a HCLPF of 0.29 g. The NRC review and closure of USI A-46 for VYNPS is documented in a letter dated March 20, 2000 (NRC 2000).

The IPEEE identifies seven opportunities for improvement related to seismic events, including improvements related to the CST and Diesel Fuel Oil Storage Tank. In response to an RAI, Entergy confirmed that, with the exception of improvements related to the CST, all the improvements identified in the IPEEE and in Tables 2.7 and 2.12 of NUREG-1742 (NRC 2002) have been implemented or otherwise shown not to be required (Entergy 2006b). In response to an RAI, Entergy evaluated a modification to raise the CST HCLPF value. This is discussed further in Section G.3.2. Based on the information provided by the applicant, the NRC staff finds the treatment of seismic events to be reasonable for the purposes of the SAMA analysis.

The VYNPS IPEEE fire analysis employed EPRI's fire-induced vulnerability evaluation methodology to perform a qualitative and quantitative screening review and then a probabilistic risk analysis to estimate the CDF contribution for the areas that did not screen out. After qualitative screening, fire event initiation frequencies were determined for the unscreened areas for use in quantitative screening along with the assumption that all equipment in a compartment was damaged by the fire. Using results from the IPE, a conservative CDF for the compartment was determined and areas with a CDF of less than 1×10^{-6} per year were screened out. Fire propagation and suppression analysis was then conducted on the unscreened compartments. Fire induced CDFs were determined by propagating the fire initiating events and associated equipment failures determined by the fire propagation and suppression analysis through event trees similar to those in the IPE. The potential impact on containment performance and isolation was evaluated following the core damage evaluation. The VYNPS fire CDF results, after updating in response to IPEEE RAIs, are presented in Table E.1-11 of the ER. The total fire CDF, found by summing the values for all compartments is 5.6×10^{-5} per year.

In the IPEEE, four opportunities for improvements with respect to fire events were identified. These improvements were all credited in the IPEEE fire CDF. Three of the four improvements involved improvements in the fire prevention inspection and barrier inspection and maintenance programs. The fourth improvement involved relocating or protecting certain control cables for offsite power breakers. In the ER, Entergy indicates that these improvements have been implemented.

The NRC staff inquired about additional steps taken to reduce fire risk and the possibility of additional SAMAs that might be feasible to reduce the fire risk. Entergy provided a listing of fire related Phase I SAMAs that have been implemented. Most of these SAMAs are improvements in the fire protection program, that while they would decrease the fire risk, are not explicitly credited in the fire risk analysis. Entergy further argued that a number of the SAMAs, identified based on internal events analysis, would also mitigate the fire risk and identified these SAMAs and the affected fire zones (Entergy 2006c). In addition, all of the dominant fire zones are equipped with fire detection systems and all but two of the zones have fire suppression systems (Entergy 2006e). Each of the dominant contributors to the total fire CDF and the associated fire detection and suppression system for those fire zones are shown in Table G-4.

The feasibility of adding fire suppression to the two remaining fire zones was examined and it was concluded that this was inappropriate to do so because of inherent complexity and competing risks associated with possible fire suppression designs. Based on the above, Entergy concluded that no additional cost effective fire related SAMAs would be expected (Entergy 2006e). The NRC staff concludes that the opportunity for fire-related SAMAs has been adequately explored and that it is unlikely that there are any potentially cost-beneficial, fire-related SAMA candidates.

In the ER, Entergy states that the above CDF values are screening values and that a more realistic fire CDF may be about a factor of three lower (or 1.86×10^{-5} per year) based on the NRC staff estimate for another license renewal application. In response to an NRC staff RAI to justify the factor of three reduction for VYNPS, Entergy identified seven general conservative assumptions applied to the fire analysis and eight conservatisms specific to fires scenarios in the control room or cable vault that are significant contributors to fire risk (Entergy 2006b). Of the fire scenario-specific conservatisms, most can be characterized by: (1) use of conservative fire frequency and severity factors, (2) no credit taken for certain plant operating procedures during fire events, and (3) use of a simple fire suppression analysis. Based on the existence of numerous conservatisms, the NRC staff finds the use of a fire CDF of 1.86×10^{-5} per year to be reasonable for the purposes of the SAMA analysis.

The IPEEE analysis of high winds, external floods and other external events followed the screening and evaluation approaches specified in Supplement 4 to GL 88-20 (NRC 1991) and

Table G-4. Dominant Contributors to Total Fire CDF at VYNPS

Fire Compartment	Description	CDF (per year)	Fire Detection	Fire Suppression Type
CV	Cable Vault, El. 262'	1.5×10^{-5}	Yes	CO_2
SGW	West Switchgear Room, El. 248'	9.0×10^{-6}	Yes	CO_2
SGE	East Switchgear Room, El. 248'	7.0×10^{-6}	Yes	CO_2
CR	Control Room, El. 272'	5.7×10^{-6}	Yes	None
RB3	Reactor Building, El. 252', Zone RB3 (north)	5.1×10^{-6}	Yes	Pre-action water
RB4	Reactor Building, El. 252', Zone RB4 (south)	3.3×10^{-6}	Yes	None
CVBT	Cable Vault Battery Room, El. 262'	3.2×10^{-6}	Yes	CO_2
TURB	Turbine Building, All General Areas	1.1×10^{-6}	Yes	Pre-action water

did not identify any significant sequences or vulnerabilities (VYNPC 1998). Based on this result, Entergy concluded that these other external hazards would not be expected to impact the conclusions of the SAMA analysis and did not consider them further.

Based on the aforementioned results, the external events CDF is approximately 2.33 times the internal events CDF (based on a negligible seismic CDF, a fire CDF of 1.86×10^{-5} per year, and an internal events CDF of 8.0×10^{-6} per year). Accordingly, the total CDF from internal and external events would be approximately 3.33 times the internal events CDF. In the revised SAMA analyses submitted in response to an RAI, Entergy multiplied the benefit that was derived from the internal events model by a factor of 3.33 to account for the combined contribution from internal and external events. The NRC staff agrees with the applicant's overall conclusion concerning the multiplier used to represent the impact of external events and concludes that the applicant's use of a multiplier of 3.33 to account for external events is reasonable for the purposes of the SAMA evaluation.

The NRC staff reviewed the general process used by Entergy to translate the results of the Level 1 PSA 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 (Entergy 2006a, 2006b, and 2006c). The current Level 2 model utilizes a single CET, containing both phenomenological and systemic events, which is linked directly to the Level 1 event trees.

Entergy characterized the releases for the spectrum of possible radionuclide release scenarios using a set of 14 release categories, defined based on the timing and magnitude of the release and whether the containment remains intact or is bypassed. The frequency of each release category was obtained from the quantification of a linked Level 1 - Level 2 model which effectively evaluates a CET for each Level 1 accident sequence. Each CET accident progression end state was assigned to one of the 14 release categories. The release characteristics for each release category were obtained by frequency weighting the release characteristics for each CET end state contributing to the release category. The source term release fractions for the CET endstates were estimated based on the results of plant-specific analyses of the dominant CET scenarios using the Modular Accident Analysis Program (MAAP, Version 4.04) computer program. The release categories, their frequencies and release characteristics are presented in Table RAI.2.b of Entergy's RAI responses (Entergy 2006c).

The NRC staff's review of the Level 2 IPE concluded that it addressed the most important severe accident phenomena normally associated with the Mark I containment type, and identified no significant problems or errors (NRC 1996). Based on the NRC staff's review of the Level 2 methodology, and the fact that the Level 2 model was reviewed in more detail as part of the BWROG peer review, the NRC staff concludes that the Level 2 PSA provides an acceptable basis for evaluating the benefits associated with various SAMAs.

Even though Entergy used the MACCS2 code and scaled the reference BWR core inventory for VYNPS plant-specific power level (1912 MWt), the NRC staff requested that Entergy evaluate the impact on population dose if the core inventory were based on the plant-specific burn-up and enrichment (NRC 2006a). In response to the NRC staff's request, Entergy derived a best estimate inventory of long-lived isotopes (such as Sr-90, Cs-134 and Cs-137) from an ORIGEN calculation assuming 4.65 percent enrichment and average burn-up based on expected fuel management practices. This resulted in an increase of approximately 25 percent in the inventories of the aforementioned radionuclides relative to those considered in the ER (Entergy 2006b). The increase in the inventories, combined with the increase in CDF in version VY05R0 of the PSA, resulted in an increase in total population dose from 9.2 to 15.1 person-rem per year, and an increase in the annual offsite economic risk monetary equivalent (discussed later) from $21,000 to $36,600 (Entergy 2006c). As part of their response, Entergy provided revised benefit estimates for each SAMA based on the revised core inventory values and the revised PSA model. The revised benefit estimates are presented and discussed in Section G.6.

The NRC staff reviewed the process used by Entergy to extend the containment performance (Level 2) portion of the PSA to an assessment of offsite consequences (essentially a Level 3 PSA). 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 release 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 2032, emergency evacuation modeling, and economic data. This information is provided in Attachment E of the ER (Entergy 2006a) and Attachment B of the RAI responses (Entergy 2006c).

Entergy used site-specific meteorological data for the 2002 calendar year as input to the MACCS2 code. The hourly data were collected from the onsite meteorological tower. In response to an RAI, Entergy stated that it considered the year 2002 data to be the most current and complete set of data at the time of the SAMA analysis (Entergy 2006b). Missing data was obtained from a backup meteorological system located on the VYNPS site. 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 2002 meteorological data in the SAMA analysis is reasonable.

The population distribution the applicant used as input to the MACCS2 analysis was estimated for the year 2032, based on the U.S. Census population data for 2000 (Entergy 2006a). The 2000 population was adjusted to account for transient population. These data were used to project county-level resident populations to the year 2032 using a least squares fit method. 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. Entergy assumed that 100 percent of the population would move at an average speed of approximately 1.8 meters per second (4 miles per hour) with a delayed start time of 1 hour and 20 minutes (Entergy 2006a). This assumption is similar to the NUREG-1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the emergency planning zone. Sensitivity analyses were performed in which the evacuation delay time was set to 2 hours, and the evacuation speed was decreased to 1 meter per second (2.2 miles per hour). The results of both sensitivity analyses showed that delayed evacuation and lower evacuation speed have a small impact on the population dose. The NRC staff concludes that the evacuation assumptions and analysis are reasonable and acceptable for the purposes of the SAMA evaluation.

Site-specific economic data requiring spatial distributions as input to MACCS2 were prepared by specifying the data for each of the 17 counties within 80 kilometers (50 miles) of the plant. The values used in each of the 240 sectors surrounding the plant corresponded to the county that made up a majority of the land in that sector. Generic economic data that are applied to the region as a whole were revised from the MACCS2 sample problem input when better information was unavailable. These included fraction of farm and non-farm wealth from improvements (e.g., buildings, equipment). The agricultural economic data were extrapolated to 2002 using average values for the 50-mile radius area from the 1987, 1992, and 1997 Census of Agriculture (USDA 1998). The recommended MACCS2 growing seasons duration was assumed.

The NRC staff concludes that the methodology used by Entergy to estimate the offsite consequences for VYNPS 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 Entergy.

G.3 Potential Plant Improvements

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

G.3.1 Process for Identifying Potential Plant Improvements

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

- Review of the most significant basic events from the plant-specific PSA,
- Review of potential plant improvements identified in the VYNPS IPE and IPEEE,
- Review of Phase II SAMAs from license renewal applications for six other U.S. nuclear sites, and
- Review of other NRC and industry documentation discussing potential plant improvements.

Based on this process, an initial set of 302 candidate SAMAs, referred to as Phase I SAMAs, was identified. In Phase I of the evaluation, Entergy 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 VYNPS due to design differences,
- The SAMA has already been implemented at VYNPS, or
- The SAMA is similar in nature and could be combined with another SAMA candidate.

Based on this screening, 236 SAMAs were eliminated, leaving 66 for further evaluation. Of the SAMAs eliminated, 57 were eliminated because the SAMA is not applicable at VYNPS because of design differences, 175 were eliminated because the SAMA has already been implemented at VYNPS, and 4 were eliminated because the SAMA is similar in nature and could be combined with another SAMA candidate. The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table E.2-1 of the ER (Entergy 2006a) and Revised Table E.2-1 of the RAI responses (Entergy 2006c). In Phase II, a detailed evaluation was performed for each of the 66 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 3.33, as previously discussed.

G.3.2 Review of Entergy's Process

Entergy's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from functional, initiating event, and risk reduction worth perspectives at VYNPS, and included selected SAMAs from prior SAMA analyses for other plants.

In Table E.1-3 of the ER, Entergy provided a tabular listing of the risk significant terms or functions in the PSA sorted according to their risk reduction worth (RRW) in PSA version VY04R1 (Entergy 2006a). A revision to this table based on PSA version VY05R0 was provided in response to an RAI (Entergy 2006d). SAMAs impacting the risk significant terms would have the greatest potential for reducing risk. Entergy used a RRW cutoff of 1.005, which corresponds to about a one-half percent change in CDF given 100-percent reliability of the SAMA. This equates to a benefit (using PSA version VY05R0) of approximately $15,000 (after the benefits have been multiplied to account for external events). Entergy correlated the terms with highest risk importance in the Level 1 PSA with the SAMAs evaluated in Phase I or Phase II, and showed that, with a few exceptions, all of the significant terms are addressed by one or more SAMAs (Entergy 2006a).

The exceptions (for which Entergy did not identify any SAMAs to address risk significant terms) are all operator action terms, in which procedure enhancements have already been implemented and further procedural changes would be of little benefit. Consequently, the only potential for reducing the risk would be to automate the operator action, if it has not already been automated. For most of these operator actions, automating the operator actions raises the potential for adverse risk impacts. For example, the operator action with the highest RRW involves aligning the John Deere diesel generator and the firewater system to provide alternate injection into the reactor for station blackout sequences. In response to NRC staff inquiries, Entergy stated that if these actions were automated and spurious operation occurred, potential serious adverse electrical and/or fluid system interaction would be possible. While it is possible to design around these interactions, this would complicate the modification and increase its cost (Entergy 2006e). Entergy concluded for this operator action that no Phase II SAMAs need be considered. With one exception, the same conclusion is reached for the other significant operator actions. The exception is automating the starting of turbine building closed cooling water (TBCCW) pumps after a loss of offsite power. For this case, the cost-benefit of automating this function was evaluated at the NRC staff's request and it was found not to be cost-beneficial (Entergy 2006c).

For a number of the Phase II SAMAs listed in the ER, the information provided did not sufficiently describe the proposed modification. Therefore, the NRC staff asked the applicant to provide more detailed descriptions of the modifications for several of the Phase II SAMAs candidates (NRC 2006a). In response to the RAI, Entergy provided the requested information (Entergy 2006b).

The NRC staff questioned the ability of some of the candidate SAMAs to accomplish their intended objectives (NRC 2006a). In response to the RAIs, Entergy addressed the NRC staff's concerns by either re-evaluating the existing SAMA using revised modeling assumptions, or by evaluating an alternative (additional) SAMA (Entergy 2006c). This is discussed further in Section G.6.2.

The NRC staff also questioned Entergy about lower cost alternatives to some of the SAMAs evaluated, including revising operator procedures to provide additional space cooling to the emergency diesel generator (EDG) room via the use of portable equipment, the use of a portable generator to power the battery chargers, and providing an auto-start feature to start a TBCCW pump automatically during a LOOP event (NRC 2006a). In response to the RAIs, Entergy addressed the suggested lower cost alternatives, some of which are covered by an existing procedure, or are addressed by a new SAMA (Entergy 2006b, 2006c, 2006d). This is discussed further in Section G.6.2.

Internal flooding initiators contribute more than 17 percent of the internal events CDF (Entergy 2006c). In the ER, Entergy only evaluated one SAMA candidate, SAMA 47, which would uniquely reduce the internal flooding contribution. In response to an RAI, Entergy indicated that a number of the SAMAs identified to mitigate non-flooding sequences would also mitigate flooding events. Fourteen opportunities were identified in the IPEEE for improvements for internal flooding. In response to the RAI, Entergy described each of the 14 improvements and confirmed that they were either implemented and credited in the PSA (10 of the 14) or were not warranted for various reasons (4 of the 14) (Entergy 2006b). In response to further NRC staff inquiry, Entergy stated that an internal flooding assessment was conducted by Entergy in 2002, subsequent to the IPEEE assessment. The assessment indicated SAMA 47 as a potential improvement and concluded that all other identified improvements to further reduce the internal flooding impact were either not feasible or excessively costly (Entergy 2006e). SAMA 47 is discussed further is Section G.6.2. Additionally, Entergy provided a revised Table E.1-3 of risk significant terms, which had changed based on the use of PSA version VY05R0. It indicated that the number of internal flooding risk significant terms had dropped as a result of the PSA revision, from 17 to nine (Entergy 2006d).

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 internal event contributors to CDF (including internal flooding).

Entergy did not identify VYNPS-specific candidate SAMAs for seismic events. In the VYNPS IPEEE seismic analysis, all high confidence low probability of failure (HCLPF) values were greater than the 0.3g review level earthquake except for the CST, which had a HCLPF value of 0.25g. NRC requested that Entergy evaluate modifications that would raise the CST HCLPF to 0.3g (NRC 2006a). Entergy indicated that the combination of strengthening the lower portion of the shell and additional anchorage would accomplish this goal. To assess the benefit, operator failure to switch over from CST suction for high-pressure coolant injection (HPCI)/reactor core isolation coolant (RCIC) to torus suction was eliminated. This resulted in a benefit (including the impact of uncertainties) of $17,000. Entergy estimated the cost of implementing this SAMA to be $1M (Entergy 2006c). This new SAMA would not be cost-beneficial at VYNPS. Therefore, no cost-effective hardware changes were identified to address the CST. Furthermore, Entergy states in the ER that several seismic-related enhancements beyond those identified in the IPEEE were evaluated, and that these enhancements were included in the comprehensive list of Phase I SAMA candidates. Entergy identified and described these SAMAs in response to an RAI (Phase I SAMAs 205 through 210 and SAMA 212) and confirmed that all of these SAMAs have been implemented (Entergy 2006b). Based on the licensee's IPEEE, the A-46 efforts to identify and address seismic outliers, the modifications that have already been implemented, and the expected cost associated with further seismic risk analysis and potential plant modifications, the NRC staff concludes that the opportunity for seismic-related SAMAs has been adequately explored and that it is unlikely that there are any cost-beneficial, seismic-related SAMA candidates.

Entergy also did not identify VYNPS-specific candidate SAMAs for fire events. The fire risk at VYNPS is dominated by eight fire areas, the largest contributor being the cable vault. The NRC staff asked the applicant to explain what measures were taken to further reduce risk and why the fire risk cannot be further reduced in a cost effective manner (NRC 2006a). In response to this request, Entergy stated that most of the fire scenarios are mitigated by SAMAs responding to internal risk contributors. Entergy also provided a list of fire-related Phase I SAMAs (214 through 224 and 282 through 284) that were previously implemented. In response to an RAI concerning the possibility of SAMAs to address fire events, Entergy pointed out that many of the Phase II SAMAs identified based on internal events risk also mitigate the fire risk. Entergy also stated that all eight dominant risk significant fire areas are equipped with a fire detection system that alarms in the control room, and that six of the eight areas are equipped with a fire suppression system. Of the two areas not equipped with fire suppression systems, Entergy indicated that installation of these systems is either not feasible or would entail excessive costs (Entergy 2006e). Therefore, no hardware changes or other modifications to further reduce the fire CDF were found to be cost-effective (Entergy 2006b).

In the IPEEE, five opportunities for improvements related to external flooding were identified. These improvements were all related to procedural enhancements to address site flooding or the sealing of conduits or walls to prevent external flood penetration (NRC 2001). In the ER, Entergy stated that all have been implemented and qualitatively discussed the residual risks from high winds, external flooding, ice, hazardous chemical transportation and nearby facility incidents. These external hazards are below the threshold screening frequency and are not expected to impact the conclusions of the SAMA analysis. Accordingly, Entergy considered the potential for SAMAs to further reduce these risks, but concluded that further modifications would not be cost-beneficial (Entergy 2006a). The NRC staff concludes that the applicant's rationale for eliminating these enhancements from further consideration is reasonable.

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 Entergy used a systematic and comprehensive process for identifying potential plant improvements for VYNPS, and that the set of potential plant improvements identified by Entergy is reasonably comprehensive and therefore acceptable. This search included reviewing insights from the plant-specific risk studies, 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 seismic and fire events 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

Entergy evaluated the risk-reduction potential of the 66 remaining SAMAs that were applicable to VYNPS. The majority of the SAMA evaluations were performed in a bounding fashion in that the SAMA was assumed to completely eliminate the risk associated with the proposed enhancement. Such bounding calculations over-estimate the benefit and are conservative.

Entergy used model re-quantification to determine the potential benefits. The CDF and population dose reductions were estimated using the VYNPS PSA model. The changes made to the model to quantify the impact of the SAMAs are detailed in Section E.2.3 of Attachment E to the ER (Entergy 2006a) and in Attachment B of the September 19, 2006 RAI responses (Entergy 2006c). Table G-5 lists the assumptions that were considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent

Table G-5. SAMA Cost-Benefit Screening Analysis for VYNPS[a]

SAMA	Assumptions	% Risk Reduction[b] CDF	Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
Additional Service Water Pump	Eliminate CDF contribution due to loss of service water.	<1	<1	24,000	34,000	5,900,000
1 - Add a service water pump.						
Redundant Train to EDG Building HVAC	Eliminate CDF contribution from EDG failures.	24	26	750,000	1,000,000	2,200,000[d]
2 - Provide a redundant train/means of EDG Room ventilation.						
Improvements Related to Diagnosis of EDG Building HVAC	Reduce probability of EDG run failures by a factor of three.	18	19	560,000	760,000	1,300,000[d]
3 - Add a diesel building high temperature alarm, or redundant louver and thermostat.						
Decay Heat Removal Capability	Completely eliminate loss of torus cooling mode of the RHR and RHRSW system events.	6	8	230,000	310,000	
4 - Install and independent method of suppression pool cooling.						5,800,000
12 - Install a passive containment spray system						5,800,000
17 - Add dedicated suppression pool cooling.						5,800,000
Filtered Vent	Bin successful torus venting sequences into the Low-Low release category	0	~0	400	500	
5 - Install a filtered containment vent to provide fission product scrubbing. Option 1: Gravel Bed Filter. Option 2: Multiple Venturi Scrubber.						3,000,000
22 - Install a filtered vent.						3,000,000

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
Containment Vent for ATWS Decay Heat Removal	Eliminate CDF contribution from loss of torus cooling mode of RHR and RHRSW in ATWS event sequences.	~0	0	0	0	
6 - Install a containment vent large enough to remove ATWS decay heat.						>2,000,000
56 - Install an ATWS sized vent.						>2,000,000
Molten Core Debris Removal	Completely eliminate containment failures due to core-concrete interaction (not including liner failure).	0	11	280,000	390,000	
7 - Create a large concrete crucible with heat removal potential under the base mate to contain molten core debris.						>100,000,000
8 - Create a water-cooled rubble bed on the pedestal.						19,000,000
11 - Create a core melt source reduction system						>1,000,000
14 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.						>5,000,000
15 - Provide a reactor vessel exterior cooling system.						2,500,000
25 - Provide a means of flooding the rubble bed.						2,500,000

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
26 - Install a reactor cavity flooding system.						8,750,000
Drywell Head Flooding	Completely eliminate drywell head failures due to high temperature.	0	0	0	0	
9 - Provide modification for flooding the drywell head.						>1,000,000
23 - Provide a method of drywell head flooding.						>1,000,000
Reactor Building Effectiveness	Bin sequences with releases into reactor building into the Low-Low release category.	0	39	940,000	1,300,000	
10 - Enhance fire protection system and standby gas treatment system hardware and procedures.						>2,500,000
16 - Construct a building connected to primary containment that is maintained at a vacuum.						>2,100,000 [d]
24 - Use alternate method of reactor building spray.						>>2,500,000 [f]
Strengthen Containment	Eliminate CDF contribution due to ATWS and loss of containment heat removal.	6	9	240,000	330,000	
13 - Strengthen primary and secondary containment.						12,000,000
18 - Create a larger volume in containment.						8,000,000

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($ [c]	Cost ($)
19 - Increase containment pressure capability (sufficient pressure to withstand severe accidents).						12,000,000
27 - Add ribbing to the containment shell.						12,000,000
Vacuum Breakers 20 - Install improved vacuum breakers (redundant valves in each line)	Eliminate vacuum breaker failures and suppression pool scrubbing failures.	~0	0	4000	5000	>1,000,000
Temperature Margin for Seals 21 - Increase the temperature margin for seals.	Eliminate containment failure due to high temperature drywell seal failure.	0	0	0	0	12,000,000
DC Power	Increase time available to recover offsite power before HPCI and RCIC are lost from 4 to 24 hours during SBO scenarios	11	11	340,000	450,000	
28 - Provide additional DC battery capacity.						1,730,000[d]
29 - Use fuel cells instead of lead-acid batteries.						>1,000,000[e]
33 - Provide 16 hour station blackout injection.						1,730,000[d]
40 - Install fuel cells.						>1,000,000[e]
41 - Extended station blackout provisions.						1,730,000[d]

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
Improved DC System	Completely eliminate failures of DC bus 1.	3	3	100,000	140,000	>500,000
30 - Provide auto-transfer of AC bus control power to a standby DC power source upon loss of the normal DC source						
Dedicated DC Power and Additional Batteries and Divisions	Completely eliminate loss of DC bus 1 and one division of DC power events (battery and bus).	6	6	180,000	240,000	
38 - Add a dedicated DC power supply.						3,000,000
39 - Install additional batteries or divisions.						3,000,000
Turbine Generator	Eliminate CDF contribution due to failure of the Vernon Tie.	29	32	920,000	1,240,000	
31 - Install a gas turbine generator.						>>2,000,000[f]
34 - Install a steam driven turbine generator.						>>2,000,000[f]
35 - Provide an alternate pump power source.						>5,000,000[e]
36 - Install a gas turbine.						>2,000,000
37 - Install a dedicated RHR (bunkered) power supply.						>2,000,000
Bypass Diesel Generator Trips	Reduce probability of EDG failing to run by a factor of three.	18	19	560,000	760,000	>1,200,000[d]
32 - Change procedure to bypass diesel generator trips, or change trip set-points.						

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
Locate RHR Inside Containment 42 - Locate residual heat removal (RHR) inside containment.	Bin ISLOCA accident sequences into the same end states as medium LOCA accident sequences.	<1	<1	20,000	28,000	>500,000
ISLOCA 43 - Increase frequency of valve leak testing.	Eliminate CDF contribution due to ISLOCA.	<1	<1	20,000	28,000	100,000
ISLOCA Release 44 - Ensure all ISLOCA releases are scrubbed.	Bin ISLOCA sequences into the Low-Low release category.	0	1	32,000	45,000	>2,500,000
Containment Isolation Valve Position Indication 45 - Add redundant and diverse limit switches to each containment isolation valve.	Eliminate CDF contribution due to ISLOCA and make containment isolation successful in the level 2 model.	<1	<1	20,000	28,000	>1,000,000
MSIV Design 46 - Improve MSIV design.	Eliminate CDF contribution due to main steam line LOCA outside containment.	~0	0	0	0	>1,000,000[e]
Shield Electrical System fro Water Spray 47 - Shield injection system electrical equipment from potential water spray.	Eliminate CDF contribution due to internal flooding initiators that could impact injection system electrical equipment.	3	2	68,000	90,000	250,000
Diesel to CST Makeup Pumps 48 - Install an independent diesel for the condensate storage tank makeup pumps.	Eliminate operator failure to switch over from CST to torus.	2	0	8000	9000	135,000

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
High Pressure Injection System	Eliminate CDF contribution due to failure of the HPCI system.	28	25	740,000	1,000,000	
49 - Provide an additional high pressure injection pump with independent diesel.						5,000,000[e]
50 - Install independent AC high pressure injection system.						5,000,000[e]
51 - Install a passive high pressure system.						28,000,000[e]
53 - Install an additional active high pressure system.						4,400,000[e]
54 - Add a diverse injection system.						4,000,000[e]
Improve the Reliability of High Pressure Injection System	Reduce the HPCI system failure probability by a factor of three.	19	17	500,000	670,000	4,000,000[e]
52 - Improved high pressure systems.						
SRV Reseat	Eliminate CDF contribution due to stuck open relief valves.	<1	37	910,000	1,280,000	4,600,000[e]
55 - Increase safety relief valve (SRV) reseat reliability.						
ATWS	Eliminate CDF contribution from ATWS sequences.	2	<1	28,000	36,000	>500,000
57 - Improve ATWS coping capability.						
Diversity of Explosive Valves	Eliminate common cause failure of SLC explosive valves.	0	0	0	0	>200,000
58 - Diversify explosive valve operation.						

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
Reliability of SRVs [g] 59 - Increase the reliability of safety relief valves by adding signals to open them automatically.	Eliminate the occurrence of all RCS overpressure events.	~ 0	0	600	700	>1,500,000
Improve SRV Design 60 - Improve SRV design.	Eliminate probability of SRV failure to open for vessel depressurization.	13	8	260,000	350,000	2,800,000[e]
Self-Cooled ECCS Pump Seals 61 - Provide self-cooled ECCS pump seals.	Eliminate CDF contribution from sequences involving RHR pump failures.	<1	0	9000	12,000	>200,000
Large Break LOCA 62 - Provide digital large break LOCA protection.	Eliminate CDF contribution due to large break LOCA.	<1	0	9000	12,000	>100,000
Controlled Containment Venting[g] **63 - Control containment venting within a narrow band of pressure.**	**Reduce probability of operator failing to vent by a factor of 3 and remove guaranteed failure of core spray and LPCI.**	**3**	**4**	**120,000**	**150,000**	**250,000**
Cross-Tie of RHRSW System to RHR Loop B 64 - Provide a crosstie from the RHRSW system to RHR loop B.	Eliminate CDF contribution from failure of firewater crosstie to RHRSW loop A.	<1	0	10,000	13,000	>500,000

Table G-5. (contd)

SAMA	Assumptions	% Risk Reduction[b] CDF	% Risk Reduction[b] Population Dose	Total Benefit Using 7% Discount Rate ($)[c]	Total Benefit Using 3% Discount Rate ($)[c]	Cost ($)
ECCS Low Pressure Interlock - Procedure Change **65 - Improve operator action: Defeat low reactor pressure interlocks to open LPCI or core spray injection valves during transients with stuck open SRVs or LOCAs in which random failures prevent all low pressure injection valves from opening.**	**Eliminate probability of ECCS low pressure permissives failing.**	**16**	**17**	**500,000**	**670,000**	**50,000**
ECCS Low Pressure Interlock - Hardware Modification **66 - Install a bypass switch to bypass the low reactor pressure interlocks of LPCI or core spray injection valves.**	**Eliminate probability of ECCS low pressure permissives failing.**	**16**	**17**	**500,000**	**670,000**	**1,000,000**

(a) SAMAs in bold are potentially cost-beneficial
(b) CDF and population dose reductions taken from a revised assessment provided in Attachment B of the RAI responses (Entergy 2006c) based on a revised internal events PSA, model VY05R0
(c) Estimated benefits taken from a revised assessment provided in Attachment B of the RAI responses (Entergy 2006c). This assessment is based on: (1) internal events PSA version VY05R0, (2) a multiplier of 3.33 to account for potential risk reduction in both internal and external events, and (3) revised core inventories to reflect expected fuel management practices at VYNPS.
(d) Estimated costs reflect revised values provided in Attachment B of the RAI responses (Entergy 2006c)
(e) Estimated costs reflect revised values provided in response to RAI 6.b (Entergy 2006c)
(f) Estimated costs reflect revised values provided in response to RAI IV.d (Entergy 2006d)
(g) The assumptions, estimated benefits, CDF and population dose reductions reflect a revised analysis provided in the RAI clarifications (Entergy 2006d)

reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The estimated benefits reported in Table G-5 reflect the combined benefit from both internal and external events, as well as a number of changes to the analysis methodology and revised VYNPS PSA subsequent to the ER. 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 benefits or risk reduction estimates of certain SAMAs provided in the ER (NRC 2006a, 2006b). For SAMA 59, increase the reliability of safety relief valves by adding signals to open them automatically, the NRC staff questioned Entergy's modeling assumption that only medium LOCAs would be impacted by this modification (NRC 2006a, 2006b). In response, Entergy re-evaluated the SAMA by eliminating the occurrence of all RCS overpressure events. This revision resulted in a negligible CDF reduction (Entergy 2006d). The NRC staff considers the revised assumptions for this SAMA to be reasonable and acceptable for purposes of the SAMA evaluation.

For Phase II SAMA 63, control containment venting within a narrow pressure band, Entergy estimated the benefit by reducing the probability of operator failure to vent by a factor of three (Entergy 2006a). The NRC staff noted that the benefit of controlled venting occurs for sequences involving successful venting, and that these sequences are not affected by reducing the operator failure to vent (NRC 2006a). In response to an RAI and a subsequent request for clarification, Entergy revised the PSA model binning rule to remove guaranteed failure of core spray and LPCI based upon successful venting of containment. This revision resulted in a CDF reduction of approximately 3.2 percent, which is slightly more than the 2.8 percent CDF reduction previously estimated, and an increase in the estimated benefit (Entergy 2006d). The NRC staff considers the revised assumptions for this SAMA to be reasonable and acceptable for purposes of the SAMA evaluation.

The NRC staff has reviewed Entergy's bases for calculating the risk reduction for the various plant improvements and concludes 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 Entergy's risk reduction estimates.

G.5 Cost Impacts of Candidate Plant Improvements

Entergy estimated the costs of implementing the 66 candidate SAMAs through the application of engineering judgement and use of other licensees' estimates for similar improvements. 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 associated with unforeseen implementation obstacles. The cost estimates provided in the ER also did not account for inflation, which is considered another conservatism. For those SAMAs whose implementation costs were originally developed for severe accident mitigation design alternative analyses (i.e., during the design phase of the plant), additional costs associated with performing design modifications to the existing plant were not included (Entergy 2006a).

The NRC staff reviewed the bases for the applicant's cost estimates (presented in Section E.2.3 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 and advanced light-water reactors. The NRC staff noted that several of the cost estimates provided by the applicant were drawn from previous SAMA analyses for a dual-unit site. As such, the cost estimates reflect implementation for two units. Also, some of the cost estimates provided (as taken from other SAMA analyses) are specific to a plant's design, such as the number of valves or batteries that would need to be replaced. Therefore, the NRC staff asked the applicant to provide appropriate cost estimates that are specific to VYNPS (NRC 2006a). In response to the NRC staff's request, Entergy provided revised cost estimates for several SAMAs (Entergy 2006c). For those cost estimates that were taken from a dual-unit SAMA analysis, Entergy reduced the estimated costs by half. For those SAMAs that required a more plant-specific cost estimate, Entergy provided new cost estimates along with a brief explanation of what the cost estimates include. Additionally, Entergy provided more refined cost estimates for other SAMAs, as a part of the revised benefit assessment. Refined cost estimates were used for SAMAs in which the revised benefits (using PSA version VY05R0) significantly changed from that provided in the ER. Revision of these cost estimates had no impact on the original conclusions that these SAMAs were not cost-beneficial (Entergy 2006c). The NRC staff reviewed the costs and subsequent cost revisions and found them to be reasonable, and generally consistent with estimates provided in support of other plants' analyses.

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

G.6 Cost-Benefit Comparison

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

G.6.1 Entergy's Evaluation

The methodology used by Entergy was based primarily on NRC's guidance for performing cost-benefit analysis, i.e., NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997b). 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. Entergy'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 three percent and one at seven percent (NRC 2004). Entergy provided both sets of estimates (Entergy 2006a).

Averted Public Exposure (APE) Costs

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δperson-rem/year)
x monetary equivalent of unit dose ($2000 per person-rem)
x present value conversion factor (10.76 based on a 20-year period with a 7-percent discount rate).

As stated in NUREG/BR-0184 (NRC 1997b), 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 due to internal events, Entergy calculated an APE of approximately $325,000 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.

For the purposes of initial screening which assumes all severe accidents due to internal events are eliminated, Entergy calculated an annual offsite economic risk of about $36,600 based on the Level 3 risk analysis. This results in a discounted value of approximately $393,000 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
x occupational exposure per core damage event
x monetary equivalent of unit dose
x present value conversion factor.

Entergy derived the values for averted occupational exposure from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997b). Best estimate values provided for immediate occupational dose (3300 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 seven percent, and a time period of 20 years to represent the license renewal period. For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, Entergy calculated an AOE of approximately $3,000 for the 20-year license renewal period.

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. Entergy derived the values for AOSC based on information provided in Section 5.7.6 of NUREG/BR-0184, the regulatory analysis handbook (NRC 1997b).

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

Averted cleanup and decontamination costs (ACC) were calculated using the following formula:

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

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in NUREG/BR-0184 to be $\$1.1 \times 10^9$ (discounted over a 10-year cleanup period). This value is integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, Entergy calculated an ACC of approximately $92,600 for the 20-year license renewal period.

Long-term replacement power costs (RPC) were calculated using the following formula:

RPC = Annual CDF reduction
x present value of replacement power for a single event
x factor to account for remaining service years for which replacement power is required
x reactor power scaling factor

For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, Entergy calculated an RPC of approximately $63,000 for the 20-yr license renewal period.

Entergy based its calculations on the value of 910 megawatts electric, which is greater than the current electrical output for VYNPS (after the extended power uprate). Therefore, Entergy conservatively did not apply power scaling factors to determine the replacement power costs. For the purposes of initial screening, which assumes all severe accidents are eliminated, Entergy calculated the AOSC to be approximately $156,000 for the 20-year license renewal period.

Using the above equations, Entergy estimated the total present dollar value equivalent associated with completely eliminating severe accidents due to internal events at VYNPS to be about $878,000. Use of a multiplier of 3.33 to account for external events increases the value to $2.9M and represents the dollar value associated with completely eliminating all internal and external event severe accident risk at VYNPS.

Entergy'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 the PSA version VY04R1, a 7-percent discount rate, and considering the combined impact of both external events and uncertainties), Entergy identified three potentially cost-beneficial SAMAs:

- SAMA 47 – shield injection system electrical equipment from potential water spray. This SAMA involves installing shields in two locations to address the impacts of breaks in either of the two locations. At the 303-ft elevation, the shields would protect the emergency core cooling system (ECCS) 24V DC distribution panel. At the 290-ft elevation, the shields would protect the ECCS instrument panel 6B (S2), channels A and C.

- SAMA 65 – modify procedures to allow operators to defeat the low reactor pressure interlock circuitry that inhibits opening the low-pressure coolant injection (LPCI) or core spray injection valves following sensor or logic failures that prevent all low pressure injection valves from opening.

- SAMA 66 – install a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry that inhibits opening the LPCI or core spray injection valves following sensor or logic failures that prevent all low pressure injection valves from opening.

Entergy performed an additional analysis to evaluate the impact of alternative discount rates on the results of the SAMA assessment. No additional SAMA candidates were determined to be potentially cost-beneficial (Entergy 2006a).

In response to an RAI, Entergy provided a revised assessment based on a separate accounting of the impacts of external events and uncertainties and the use of PSA version VY05R0 (Entergy 2006c). The revised baseline assessment resulted in identification of only one potentially cost-beneficial SAMA (SAMA 65). However, when accounting for uncertainties, SAMA 66 was also potentially cost-beneficial. (SAMA 47, which was marginally cost-beneficial in Entergy's original SAMA assessment, is not cost-beneficial in the revised assessment. This shift is due to a reduction in the multipliers used in the revised assessment for external events and uncertainties, which had multiple conservatisms in the ER.) However, in response to NRC staff inquiries regarding estimated benefits for certain SAMAs and lower cost alternatives, four additional potentially cost-beneficial SAMAs were identified. The potentially cost-beneficial SAMAs, and Entergy's plans for further evaluation of these SAMAs are discussed in more detail in Section G.6.2.

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

The cost-benefit analysis performed by Entergy was based primarily on NUREG/BR-0184 (NRC 1997b) and was executed consistent with this guidance.

In the ER, Entergy evaluated the reduction in risk for each SAMA in the context of an upper bound analysis which combined the impact of external events with the impact of uncertainties. Entergy bounded the combined impact of external events and uncertainties in the ER by applying a multiplier of 10 to the estimated SAMA benefits in internal events.

The NRC staff requested that the baseline evaluation be revised to include only the impact of internal and external events (without uncertainties), and that the impact of analysis uncertainties on the SAMA evaluation results be considered separately (NRC 2006a). Given that a revised

CDF was provided in the RAI response (using PSA version VY05R0), Entergy applied the NRC staff request to a revised set of CDF values. The impact of external events was considered by applying a multiplier of 3.33 to the estimated SAMA benefits in internal events (1+ [negligible seismic CDF + fire CDF of 1.86×10^{-5} per year] / [internal events CDF of 7.98×10^{-6} per year]). Additionally, Entergy revised the consequence analyses on which the benefit estimates are based to account for fuel enrichment and burn-up expected during the period of extended operation.

As a result of the revised baseline analysis (using PSA version VY05R0, a multiplier of 3.33 and a 7 percent real discount rate), Entergy found that only one SAMA candidate remained potentially cost-beneficial. SAMA 65 remained cost-beneficial, while SAMAs 47 and 66 were no longer cost-beneficial. When benefits were evaluated using a 3 percent discount rate, as recommended in NUREG/BR-0058, Revision 4 (NRC 2004), no additional SAMAs were determined to be potentially cost-beneficial.

Entergy considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. In the revised ER, Entergy presents the results of an uncertainty analysis of the internal events CDF which indicates that the 95 percentile value is a factor of 2.15 times the mean CDF. Information regarding the uncertainty distribution of the internal events CDF of the revised analysis (using PSA version VY05R0) is summarized in Table G-6 (Entergy 2006c). Entergy re-examined the Phase II SAMAs in the revised assessment to determine if any would be potentially cost-beneficial if the revised baseline benefits were increased by an additional factor of 2.15. One additional potentially cost-beneficial SAMA was identified (SAMA 66). SAMA 47, which was marginally cost-beneficial in Entergy's original SAMA assessment, is not cost-beneficial in the revised assessment. This shift is due to a reduction in the multipliers used in the revised assessment for external events and uncertainties, which had multiple conservatisms in the ER.

Table G-6. Uncertainty in the Calculated CDF for VYNPS

Percentile	CDF (per year)
5^{th}	3.81×10^{-6}
50^{th}	6.78×10^{-6}
mean	8.42×10^{-6}
95^{th}	1.81×10^{-5}

Entergy has submitted the potentially cost-beneficial SAMAs 65 and 66 for engineering project cost-benefit analysis. Given that SAMA 47 was no longer found to be potentially cost-beneficial using PSA version VY05R0, Entergy does not plan to evaluate this SAMA for implementation (Entergy 2006d).

The NRC staff questioned the ability of some of the candidate SAMAs identified in the ER to accomplish their intended objectives (NRC 2006a). This included Phase II SAMA 46, improved MSIV design, Phase II SAMA 47, shield injection system electrical equipment from potential water spray, and Phase II SAMA 63, control containment venting within a narrow pressure band. In response, Entergy provided further clarification or revised evaluations (Entergy 2006b, 2006c, 2006d). Of particular note is the revised evaluation of Phase II SAMA 63.

Phase II SAMA 63, control containment venting within a narrow pressure band, was identified as a potential SAMA to prevent rapid containment depressurization when venting, thus avoiding adverse impacts on the ability of low pressure injection systems to take suction from the torus. As described in Section G.4, Entergy revised the PSA model binning rule to remove guaranteed failure of core spray and LPCI based upon successful venting of containment to address the NRC staff's concerns with the benefit assessment. This revision resulted in a CDF reduction of approximately 3.2 percent and Entergy estimated the benefit (not including the impact of uncertainty) to be approximately $116,000 (Entergy 2006d). The estimated cost of implementing this SAMA is approximately $250,000 (Entergy 2006c). The NRC staff notes that when the impact of uncertainties is included, the benefit of SAMA 63 becomes approximately $250,000. Therefore, SAMA 63 is potentially cost-beneficial.

The NRC staff also requested that the applicant provide an evaluation of the costs and benefits of converting the vent system to a passive design or adding redundant components. In response, Entergy evaluated three new SAMAs. The benefit associated with conversion of the existing torus to a passive torus vent was estimated to result in a CDF reduction of 4.5 percent, and a benefit (including the impact of uncertainties) of $370,000. However, Entergy estimated the cost of implementing this SAMA to be approximately $980,000 (Entergy 2006c). Additionally, Entergy evaluated two new SAMAs associated with adding redundant components. The first SAMA proposed providing an alternate power source to torus vent valve V-16-19-86. The second SAMA proposed providing a redundant vent path. The cost of these modifications were estimated at $720,000 and $1.5M, respectively. In an RAI clarification, Entergy stated that the benefit associated with converting the existing torus vent to a passive design can be used as a bounding (conservative) estimate for the two new SAMAs. While the two new SAMAs mitigate the failure of specific components, operator failure to implement torus venting remains the dominant contributor to CDF. As such, implementation of either of these alternative SAMAs would provide a benefit less than $370,000 (Entergy 2006d), and would not be cost-beneficial at VYNPS.

The NRC staff noted that 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 several lower cost alternatives to the SAMAs considered in the ER, including SAMAs that had been found to be potentially cost-beneficial at other BWR plants. These alternatives included: (1) revising operator procedures to provide additional space cooling to the EDG room via the use of portable equipment, (2) using a portable generator to power the battery chargers, (3) providing an auto-start feature to start a TBCCW pump automatically during a LOOP event, (4) providing alternate direct current (DC) feeds to panels supplied only by DC bus, and several additional alternatives (NRC 2006a). Entergy provided a further evaluation of these alternatives, as summarized below.

- Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment (in lieu of a redundant train of EDG room ventilation considered in Phase II SAMA 2) – Based on a bounding analysis in which EDG failures were set to zero, Entergy estimated that this SAMA would result in a CDF reduction of about 24 percent, a population dose reduction of 26 percent and a benefit (including the impact of uncertainties) of $1,610,000. Entergy estimated the cost of implementing this SAMA to be approximately $50,000 (Entergy 2006c). Therefore, Entergy concluded that this low-cost alternative is potentially cost-beneficial for VYNPS.

- Use a portable generator to power the battery chargers -- in response to the NRC staff's inquiry regarding use of a portable generator, Entergy stated that upon a complete SBO, a portable generator could be used to extend the life of both 125 VDC batteries. To assess the benefit, the time available for recovery of offsite power was increased from 4 hours to 24 hours for SBO scenarios. This resulted in a benefit (with uncertainties) of approximately $723,000 (Entergy 2006c). Entergy estimated the cost of implementing this SAMA to be $712,000. Therefore, Entergy concluded that this low-cost alternative is potentially cost-beneficial for VYNPS.

- Provide an auto-start feature to start a TBCCW pump automatically during a LOOP event – to assess the benefit, Entergy created a model with the operator action to start a TBCCW pump set to guaranteed success. This resulted in a CDF reduction of 1.4 percent and a benefit (including the impact of uncertainties) of $49,000. (Entergy 2006c). Entergy estimated the cost of implementing this SAMA to be greater than $100,000. Therefore, this new SAMA would not be cost-beneficial at VYNPS.

- Use a portable generator to provide power to individual 125VDC motor control centers (MCCs) upon loss of a DC bus - To conservatively assess the benefit, Entergy set the failure of the HPCI system to zero. This is equivalent to the benefit assessment for SAMA 49, or approximately $1.6M (including the impact of uncertainties). Entergy estimated the cost of implementing and using the portable generator to be $712,000 (Entergy 2006d). Therefore, Entergy concluded that this low-cost alternative is potentially cost-beneficial for VYNPS.

- Entergy indicated that the remaining low cost alternatives identified by the NRC staff are either already addressed by existing plant procedures, or by a Phase II SAMA.

The NRC staff notes that Entergy has submitted SAMAs 65 and 66 for engineering project cost-benefit analysis. However, four additional potentially cost-beneficial SAMA were identified as a result of the NRC staff review, i.e., (1) control containment venting within a narrow pressure band (SAMA 63), (2) operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment, (3) use a portable diesel generator to extend the life of the 125 VDC batteries, and (4) use a portable generator to provide power to individual 125VDC MCCs upon loss of a DC bus. These SAMAs should also be included in the set of SAMAs to be further evaluated by Entergy.

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

G.7 Conclusions

Entergy compiled a list of 302 SAMAs based on a review of the most significant basic events from the plant-specific PSA, insights from the plant-specific IPE and IPEEE, Phase II SAMAs from license renewal applications for other plants, and review of other NRC and industry documentation concerning potential plant improvements. A qualitative screening removed SAMA candidates that (1) were not applicable at VYNPS due to design differences, (2) had already been implemented at VYNPS, or (3) were similar and could be combined with another SAMA. Based on this screening, 236 SAMAs were eliminated leaving 66 candidate SAMAs for evaluation.

For the remaining SAMA candidates, a more detailed design and cost estimate were developed as shown in Table G-5. The cost-benefit analyses in the original ER showed that three SAMA candidates were potentially cost-beneficial in the baseline analysis (Phase II SAMAs 47, 65 and 66). In a revised analysis, Entergy evaluated the same SAMA candidates using a later version of the PSA, new multipliers to account for external events and uncertainties, and core inventory values that better reflect plant-specific fuel management practices. This showed that one SAMA was potentially cost-beneficial in the baseline analysis (Phase II SAMA 65), and one additional SAMA was potentially-cost beneficial when analysis uncertainties are considered (SAMA 66). (SAMA 47, which was marginally cost-beneficial in Entergy’s original assessment, is not cost-beneficial in the revised analysis.) Entergy has indicated that Phase II SAMAs 65 and 66 have been submitted for engineering project cost-benefit analysis. The NRC staff concurs that these two SAMAs are potentially cost-beneficial. In addition, as a result of the NRC staff review, four additional SAMAs were also found to be potentially cost-beneficial, i.e., (1) control containment venting within a narrow pressure band (SAMA 63), (2) operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment, (3) use a portable diesel generator to extend the life of the 125 VDC batteries, and (4) use a portable generator to provide power to individual 125VDC MCCs upon loss of a DC bus. These SAMAs should also be included in the set of SAMAs to be further evaluated by Entergy.

The NRC staff reviewed the Entergy 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 Entergy 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 Entergy's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of all or a subset 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 Entergy 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.

G.8 References

10 CFR Part 54. *Code of Federal Regulations*, Title 10, *Energy*, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

Electric Power Research Institute. 1991. *A Methodology for Assessment of Nuclear Power Plant Seismic Margins*, Revision 1. EPRI Report NP-6041-SL.

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2003. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) Technical Specification Proposed Change No. 263 Extended Power Uprate.* Brattleboro, Vermont. (September 10, 2003).

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2004. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) Technical Specification Proposed Change No. 263, Supplement No. 5 Extended Power Uprate - Response to Request for Additional Information.* Brattleboro, Vermont. (January 31, 2004).

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2006a. *Applicant's Environmental Report – Operating License Renewal Stage, Vermont Yankee Nuclear Power Station*. Docket No. 50-271. Brattleboro, Vermont. (January 25, 2006).

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2006b. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) License Renewal Application, Amendment 7.* Entergy Nuclear Operations, Inc., Brattleboro, Vermont. (August 1, 2006).

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2006c. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) License Renewal Application, Amendment 13.* Entergy Nuclear Operations, Inc., Brattleboro, Vermont. (September 19, 2006).

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2006d. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) License Renewal Application, Amendment 18.* Entergy Nuclear Operations, Inc., Brattleboro, Vermont. (October 20, 2006).

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy). 2006e. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) License Renewal Application, Amendment 21.* Entergy Nuclear Operations, Inc., Brattleboro, Vermont. (November 6, 2006).

U.S. Department of Agriculture (USDA). 1998. 1997 Census of Agriculture, National Agriculture Statistics Service, 1998. Available URL: http://www.nass.usda.gov/census/census97/volume1/vol1pubs.htm (Accessed September 1, 2006)

U.S. Nuclear Regulatory Commission (NRC). 1990. *Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants.* NUREG-1150, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1991. *Procedural and Submittal Guidance for the Individual Plant Examination of External Events for Severe Accident Vulnerabilities.* NUREG-1407, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1996. Letter from Daniel H. Dorman, U.S. NRC, to Donald A. Reid, VYNPS. *Vermont Yankee Nuclear Power Station Individual Plant Examination (IPE) - Internal Events (TAC No. M74484).* (February 9, 1996).

U.S. Nuclear Regulatory Commission (NRC). 1997a. *Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance.* NUREG-1560, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997b. *Regulatory Analysis Technical Evaluation Handbook*. NUREG/BR-0184, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2000. Letter from Richard P. Croteau, U.S. NRC to Samuel L. Newton, VYNPS. *Vermont Yankee Nuclear Power Station - Safety Evaluation Report for Unresolved Safety Issue (USI) A-46 Program Implementation (TAC No. M69490)*. (March 20, 2000).

U.S. Nuclear Regulatory Commission (NRC). 2001. Letter from Robert M. Pulsifer, U.S. NRC to Michael A. Balduzzi, VYNPS. *Vermont Yankee Nuclear Power Station - Individual Plant Examination of External Events (IPEEE) Submittal (TAC No. M83689).* (March 22, 2001).

U.S. Nuclear Regulatory Commission (NRC). 2002. *Perspectives Gained From the IPEEE Program,* Final Report, Vols. 1 and 2, NUREG-1742, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2004. *Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission.* NUREG/BR-0058, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2005. Letter from Mark P. Rubin, U.S. NRC to Darrell J. Roberts, U.S. NRC. *Safety Evaluation Report Input Concerning the Risk Evaluation of the Vermont Yankee Nuclear Power Station Extended Power Uprate Application (TAC No. MC0761).* (October 3, 2005).

U.S. Nuclear Regulatory Commission (NRC). 2006a. Letter from Richard L. Emch, U.S. NRC, to Michael Kansler, Entergy. *Request for Additional Information Regarding Severe Accident Mitigation Alternatives for the Vermont Yankee Nuclear Power Station (TAC No. MC9670)*. (June 1, 2006).

U.S. Nuclear Regulatory Commission (NRC). 2006b. E-mail from Richard L. Emch, U.S. NRC, to Michael Hamer, Entergy. *Request for Clarification Regarding Responses to RAIs for Severe Accident Mitigation Alternatives for the Vermont Yankee Nuclear Power Station (TAC No. MC9670).* (September 27, 2006).

Vermont Yankee Nuclear Power Corporation (VYNPC). 1998. Letter from Don M. Leach, VYNPS to NRC Document Control Desk. *Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) Submittal of the Vermont Yankee Individual Plant Examination for External Events (IPEEE) Report - Response to Generic Letter 88-20, Supplement 4*. (June 30, 1998).

NRC FORM 335 (9-2004) NRCMD 3.7 **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	U.S. NUCLEAR REGULATORY COMMISSION	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.) NUREG-1437, Supplement 30 Volume 2, Appendices
2. TITLE AND SUBTITLE Generic Environmental Impact Statement for License Renewal of Nuclear Plants Supplement 30 Regarding Vermont Yankee Nuclear Power Station Final Report Volume 2, Appendices		3. DATE REPORT PUBLISHED MONTH: August YEAR: 2007 4. FIN OR GRANT NUMBER
5. AUTHOR(S) See Appendix B of Volume 2 of the document		6. TYPE OF REPORT Technical 7. PERIOD COVERED *(Inclusive Dates)*

8. PERFORMING ORGANIZATION - NAME AND ADDRESS *(If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)*

Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

9. SPONSORING ORGANIZATION - NAME AND ADDRESS *(If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)*

Same as Block 8

10. SUPPLEMENTARY NOTES

Docket No. 50-271

11. ABSTRACT *(200 words or less)*

This final supplemental environmental impact statement (SEIS) has been prepared in response to an application submitted to the NRC by Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy) to renew the operating license for Vermont Yankee Nuclear Power Station (VYNPS) for an additional 20 years under 10 CFR Part 54. This SEIS includes the NRC staff's analysis that considers and weighs the environmental impacts of the proposed action, the environmental impacts of alternatives to the proposed action, and mitigation measures available for reducing or avoiding adverse impacts. It also includes the staff's recommendation regarding the proposed action.

The NRC staff's recommendation is that the Commission determine that the adverse environmental impacts of license renewal for VYNPS are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. This recommendation is based on (1) the analysis and findings in the GEIS; (2) the Environmental Report submitted by Entergy; (3) consultations with Federal, State, and local agencies; (4) the staff's own independent review; and (5) the staff's consideration of public comments.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*	
VYNPS, Vermont Yankee, Vermont Yankee Nuclear Power Station SEIS, Supplemental EIS Supplement to the Generic Environmental Impact Statement GEIS NEPA Environmental Environmental Impact Statement License Renewal	13. AVAILABILITY STATEMENT unlimited 14. SECURITY CLASSIFICATION *(This Page)* unclassified *(This Report)* unclassified 15. NUMBER OF PAGES 16. PRICE