Appendix G

Severe Accident Mitigation Alternatives

Appendix G:
Severe Accident Mitigation Alternatives

G.1 Introduction

Entergy Nuclear FitzPatrick, LLC, and Entergy Nuclear Operations, Inc. (Entergy) submitted an assessment of severe accident mitigation alternatives (SAMAs) for the James A. FitzPatrick Nuclear Power Plant (JAFNPP) as part of the environmental report (ER) (Entergy 2006a). Supplemental information on the SAMA assessment was provided in Amendment 1 to the license renewal application (Entergy 2006b). This assessment was based on the most recent JAFNPP probabilistic safety assessment (PSA) available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 (MACCS2) computer code, and insights from the JAFNPP individual plant examination (IPE) (NYPA 1991) and individual plant examination of external events (IPEEE) (NYPA 1996). In identifying and evaluating potential SAMAs, Entergy considered SAMA that addressed the major contributors to core damage frequency (CDF) and population dose at JAFNPP, as well as SAMA candidates for other operating plants which have submitted license renewal applications. Entergy identified 293 potential SAMA candidates. This list was reduced to 63 unique SAMA candidates by eliminating SAMAs that: are not applicable to JAFNPP due to design differences, have already been implemented at JAFNPP, 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 November 29, 2006 (NRC 2006). Key questions concerned: major plant and modeling changes incorporated within each evolution of the PSA model; source term and release time category assumptions used in the Level 2 analysis; justification for the multiplier used for external events; identification of SAMAs to reduce the fire CDF; and further information on several specific candidate SAMAs and low cost alternatives. Entergy submitted additional information by letters dated December 6, 2006 (Entergy 2006b) and January 29, 2007 (Entergy 2007). In the responses, Entergy provided: a summary of the major changes made to each PSA model version and resultant changes to dominant risk contributors to CDF; a discussion of the Level 2 analysis and the process for assigning severe accident source terms and binning release categories; a revised assessment of the baseline SAMA benefits considering a multiplier to account for external events exclusive of uncertainties; a discussion of measures that have been taken to reduce risk in dominant fire zones and why the fire CDF for those zones cannot be further reduced in a cost effective manner; and additional information regarding several specific SAMAs. Entergy's responses addressed the NRC staff's concerns.

G.2 Estimate of Risk for JAFNPP

Entergy's estimates of offsite risk at JAFNPP 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 JAFNPP Level 1 and 2 PSA model, which is an updated version of the IPE (NYPA 1991), and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PSA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent JAFNPP Level 1 and Level 2 PSA model available at the time of the ER, referred to as the JAFNPP PSA (Revision 2, October 2004 model). The scope of the JAFNPP PSA does not include external events.

The baseline CDF for the purpose of the SAMA evaluation is approximately 2.74×10^{-6} per year. The CDF is based on the risk assessment for internally initiated events. Entergy did not include the contribution from external events within the JAFNPP risk estimates; however, it did account for the potential risk reduction benefits associated with external events by multiplying the estimated benefits for internal events by a factor of 4.[(1)] 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 (Entergy 2007). As shown in this table, events initiated by station blackout and transients are the dominant contributors to the CDF. Anticipated transient without scram (ATWS) sequences are insignificant contributors to the CDF.

The Level 2 JAFNPP 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. The Level 1 core damage sequences are binned into one of 48 Plant Damage State (PDS) bins which provide the interface between the Level 1 and Level 2 CET analysis. CET nodes are evaluated using supporting fault trees and logic rules.

The result of the Level 2 PSA is a set of 7 release categories with their respective frequency and release characteristics. The results of this analysis for JAFNPP are provided in

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(1) In the ER, Entergy bounded the combined impact of external events and uncertainties by applying a multiplier of 16 to the estimated SAMA benefits for internal events. In supplemental information to the ER, Entergy revised the analysis to include a multiplier of 4 to account for potential SAMA benefits in both internal and external events, and provided a separate accounting of uncertainties.

Table E.1-10 of the ER (Entergy 2006a). The frequency of each release category was obtained by summing the frequency of the individual accident progression CET endpoints binned into the release category. Source terms were developed for each of the 7 release categories using the results of Modular Accident Analysis Program (MAAP 4.0.4) computer code calculations. These release categories and source terms were further collapsed into three distinct source term bins to represent no containment failure, early releases, and late releases.

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

Initiating Event	CDF (per year)	Percent Contribution to CDF
Station Blackout	1.27×10^{-6}	46
Transients with loss of containment heat removal	7.78×10^{-7}	28
Transients with loss of all emergency core cooling system (ECCS) injection	2.66×10^{-7}	10
ATWS	1.38×10^{-7}	5
Loss of a 4.16kv alternating current (AC) safeguard bus	1.18×10^{-7}	5
Loss of both direct current (DC) divisions	9.55×10^{-8}	3
Loss of coolant accidents (LOCAs)	2.83×10^{-8}	1
Loss of a division of DC power	2.60×10^{-8}	1
Relay room flooding	2.53×10^{-8}	1
Total CDF (internal events)	$\mathbf{2.74 \times 10^{-6}}$	**100**

The offsite consequences and economic impact analyses use the MACCS2 code to determine the offsite risk impacts on the surrounding environment and public. Inputs for these analyses include plant-specific and site-specific input values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mile radius) for the year 2034, emergency response evacuation modeling, and economic data. The core radionuclide inventory is derived from a reference core inventory for a boiling water reactor (BWR) in MACCS2. Core inventory was scaled to account for the JAFNPP-specific power level, and long-lived radionuclide inventory was increased by 25 percent to reflect the expected core exposure and fuel management practices at JAFNPP (Entergy 2007). The magnitude of the onsite impacts (in terms of clean-up and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997a).

In the ER, Entergy estimated the dose to the population within 50 miles of the JAFNPP site to be approximately 1.63 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 late time frame (greater than 24 hours following event initiation) and the early time frame (0 to 24 hours following event initiation) dominate the population dose risk at JAFNPP, contributing about equally to the population dose risk.

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

Containment Release Mode	Population Dose (Person-Rem[a] Per Year)	Percent Contribution
Late Containment Failure	0.87	53
Early Containment Failure	0.76	47
Intact Containment	negligible	negligible
Total	**1.63**	**100**

(a) One person-rem = 0.01 person-Sv

G.2.2 Review of Entergy's Risk Estimates

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

- The Level 1 and 2 risk models that form the bases for the 1991 IPE submittal (NYPA 1991), and the external event analyses of the 1996 IPEEE submittal (NYPA 1996),
- The major modifications to the IPE model that have been incorporated in the JAFNPP PSA, and
- 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 JAFNPP IPE is described in an NRC report dated May 9, 1994 (NRC 1994). Based on a review of the IPE submittal and responses to RAIs, the NRC staff concluded that the IPE submittal met the intent of GL 88-20 (NRC 1988); that is, the licensee's IPE process is capable of identifying severe accident risk contributors or vulnerabilities.

No vulnerabilities were identified in the IPE. However, the licensee noted that a number of actions were under evaluation as a result of the IPE process that would reduce the risk of core damage and loss of containment function. Specific improvements identified for implementation included: increasing the reactor core isolation cooling (RCIC) turbine exhaust set points, repowering the RCIC enclosure exhaust fans from AC to DC, and fire protection system modifications to provide emergency diesel generator (EDG) jacket water cooling directly or through the emergency service water (ESW) system. Over 10 additional items were identified for follow-on evaluation by the licensee (NRC 1994).

There have been two revisions to the IPE model since the 1991 IPE submittal, specifically, a complete revision of the model in 1998 (Revision 1) in partial response to the boiling-water reactor owner group (BWROG) peer review, and a revision in October 2004 (Revision 2) completing the response to the BWROG peer review. The Revision 2 model reflects the JAFNPP configuration and design as of December 2003 and uses component failure and unavailability data as of December 2002. A comparison of internal events CDF between the 1991 IPE and the current PSA model indicates an increase of about 40 percent in the total CDF (from 1.9×10^{-6} per year to 2.7×10^{-6} per year). A listing of those changes that resulted in the greatest impact on the internal events CDF was provided by Entergy in supplemental information to the ER (Entergy 2006b) and in response to an RAI (Entergy 2007) and is summarized in Table G-3.

The CDF value from the 1991 IPE (1.92×10^{-6} per year) is near the lower end of the range of the CDF values reported in the IPEs for other BWR 3/4 plants. Figure 11.2 of NUREG-1560 shows that the IPE-based total internal events CDF for BWR 3/4 plants ranges from 9×10^{-8} per year to 8×10^{-5} per year, with an average CDF for the group of 2×10^{-5} per year (NRC 1997b). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes. The current internal events CDF results for JAFNPP are comparable to that for other plants of similar vintage and characteristics.

The NRC staff considered the peer reviews performed for the JAFNPP PSA, and the potential impact of the review findings on the SAMA evaluation. In the ER (Entergy 2006a) and in response to an NRC staff RAI (Entergy 2007), Entergy described the previous peer reviews, including independent consultant team reviews of draft versions of the IPE and Revision 1, as well as the BWROG Peer Review of a draft of Revision 1 conducted in December 1997. The BWROG review concluded that the JAFNPP PSA can be effectively used to support risk ranking of systems, structures, and components, and to support applications involving risk significance determinations when supported by deterministic analyses and when noted items are addressed. Entergy stated that all major issues and observations from the BWROG Peer Review have been addressed and incorporated into the current PSA (Revision 2).

Table G-3. JAFNPP PSA Historical Summary

PSA Version	Summary of Changes from Prior Model	CDF (per year)
1991	IPE Submittal	1.92×10^{-6}
1998 (Revision 1)	• Incorporated impact of design changes (supply EDG jacket cooling water through the ESW system cross-tie, bonnet vents on the low-pressure coolant injection (LPCI) and core spray injection valves, keylock bypass switches, normal position of residual heat removal (RHR) minimum flow bypass valve, and RCIC enclosure fan power supply changed to an AC inverter feed from a DC power source) • Revised model to include catastrophic common cause failure of both 125V DC battery control boards, and other common cause equipment failures • Revised model to assume loss of all AC power in the same division in which there is a loss of DC power • Revised internal flooding analysis to include a relay room flooding scenario • Revised transient sequences to directly result in core damage if manual depressurization of the reactor vessel fails • Revised model to assume core damage occurs given failure to initiate Standby Liquid Control System (SLCS) • Updated initiating event frequencies and component failure and unavailability database	2.44×10^{-6}
2004 (Revision 2)	• Reduced station battery depletion time from 8 to 4 hours, and updated non-recovery probabilities for loss of offsite power • Revised model to include additional accident initiators: loss of non-safeguard 4.16kV AC Buses, loss of condensate system, loss of instrument air system, loss of ultimate heat sink, and loss of reactor water level instrumentation • Revised model to assume loss of both high-pressure coolant injection (HPCI) and RCIC during accidents involving a loss of containment heat removal • Revised system fault tree models to include additional electrical and instrumentation and control (I&C) component common cause failures • Reevaluated dependencies between post-initiator human actions and recovery actions • Updated initiating event frequencies and component failure data	2.74×10^{-6}

Given that the JAFNPP internal events PSA model has been peer-reviewed and the peer review findings were all addressed, 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 JAFNPP PSA does not include external events. In the absence of such an analysis, Entergy used the JAFNPP IPEEE to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences, as discussed below.

The JAFNPP IPEEE was submitted in June 1996 (NYPA 1996), in response to Supplement 4 of Generic Letter 88-20 (NRC 1991b). 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 as discussed below. In a letter dated September 21, 2000, the NRC staff concluded that the submittal met the intent of Supplement 4 to Generic Letter 88-20, and that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities (NRC 2000a).

The JAFNPP IPEEE seismic analysis (NYPA 1996) utilized a seismic margin assessment (SMA) approach following NRC guidance (NRC 1991a) and Electric Power Research Institute (EPRI) guidance (EPRI 1991). This method is qualitative and does not provide numerical estimates of the CDF contributions from seismic initiators. The seismic analysis was completed in conjunction with the Seismic Qualification User Group (SQUG) program (SQUG 1992). The overall seismic approach employed plant walkdowns to identify vulnerabilities, development of seismic fragility values for components and structures, and quantification of high confidence low probability of failure (HCLPF) for initiating events. A relay chatter evaluation was performed using the standard approach for an Unresolved Safety Issue (USI) A-46 (NRC 2000b) program plant. The conclusions of the JAFNPP IPEEE seismic margin analysis are:

- The overall plant HCLPF capacity at JAFNPP is 0.22g peak ground acceleration (PGA). This value reflects implemented improvements to strengthen block walls in the Emergency Diesel Generator Building, which increased the plant HCLPF value from 0.17g to 0.22g. Several buildings and structures have HCLPF values at the 0.22g level. Thus, further increases in seismic capacity would require multiple plant modifications.

- A vulnerability to fire or explosion as a result of the seismic-induced failure of the hydrogen line in the turbine building was identified. A note was added to procedure AOP-14, "Earthquake," stating that the piping can be isolated by closing the hydrogen supply valve 89A-H2HAS-1. Based on this procedure change, the applicant concludes that seismic-induced flooding and fires do not pose major risks.

- No unique decay heat removal vulnerabilities to seismic events were found.

- No unique seismic-induced containment failure mechanisms were identified.

The NRC review and closeout of USI A-46 for JAFNPP is documented in a letter dated April 12, 2000 (NRC 2000b). Based on the information provided by the applicant, the NRC staff finds that seismic risks are not dominant contributors to external event risk and that the treatment of seismic events is reasonable for the purposes of the SAMA analysis.

The JAFNPP IPEEE fire analysis employed EPRI's fire-induced vulnerability evaluation (FIVE) 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 (or 1×10^{-7} per year if containment bypass may result) 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 JAFNPP fire CDF results are presented in Table E.1-12 of the ER for the ten fire areas considered in the analysis, and the fire zones/compartments within each fire area. The total fire CDF, found by summing the values for all compartments, is 2.56×10^{-5} per year. The ten fire areas and their contributions to the fire CDF are listed in Table G-4.

In the IPEEE, three opportunities for improvements with respect to fire events were identified. These improvements involve: (1) addition of a bypass switch to allow opening of the LPCI and core spray injection valves and an associated procedure for use of these switches during plant fires, (2) changes to administrative procedures to impose strict limitations on unattended combustible materials in the cable spreading room, and (3) relocation of heat detectors in the cable spreading room to limit contribution from transient fires. In supplemental information to the ER, Entergy indicated that the first two of these improvements have been implemented as recommended in the IPEEE. The third improvement is considered to be addressed by the changes to administrative procedures to limit unattended combustible material loading in the room. Entergy stated that none of these improvements are credited in the IPEEE fire CDF (Entergy 2006b).

In the ER, Entergy states that the IPEEE CDF values are screening values and that a more realistic fire CDF may be about a factor of three lower (or 8.53×10^{-6} per year) based on conservatisms in several areas as qualitatively assessed in the ER. In supplemental information, Entergy presented the results of a sensitivity analysis to quantitatively justify the factor of three reduction (Entergy 2006b). The sensitivity analysis included the following: (1) lower probability of occurrence of spurious actuation or failure due to hot shorts and open circuits within cable jackets in the Cable Spreading Room, Reactor Building East Crescent, and Relay Room and (2) lower ignition frequency for a fire in the Main Control Room. The results of this sensitivity analysis are shown for the four impacted areas in the last two columns of the table below. These reductions would quantitatively justify a reduction in the fire CDF by a factor of 2.3.

Table G-4. Fire Areas and Their Contribution to the Fire CDF

Fire Area Description	CDF (per year)	
	IPEEE	Sensitivity Analysis[a]
Cable Spreading Room	6.71×10^{-6}	4.66×10^{-7}
Relay Room	5.81×10^{-6}	6.8×10^{-7}
Reactor Building	3.43×10^{-6}	2.46×10^{-6}
Control Room	3.00×10^{-6}	7.17×10^{-7}
Cable Tunnels	1.96×10^{-6}	no change
Diesel Generator Building	1.93×10^{-6}	no change
Battery Room	1.45×10^{-6}	no change
Turbine Building	1.29×10^{-6}	no change
Standby Gas Treatment Building	3.72×10^{-8}	no change
Electric Bays	8.98×10^{-6}	no change
TOTAL	2.56×10^{-5}	1.10×10^{-5}

(a) Source: Entergy 2006b

Entergy noted that this fire CDF would be further reduced by IPEEE improvements not included in the CDF estimate, including monitoring and controlling the quantity of combustible materials in critical process areas. These measures would reduce the fire CDF in all dominant fire zones. Based on the results of the sensitivity analysis and the existence of remaining conservatisms, the NRC staff finds the use of a fire CDF of 8.53×10^{-6} per year to be reasonable for the purposes of the SAMA analysis.

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 SAMAs that have been implemented. Most of these SAMAs are improvements in the fire protection program, which would decrease the fire risk, but are not explicitly credited in the fire risk analysis. In addition, all but one of the six dominant fire zones (i.e., zones within the above-mentioned fire areas with a compartment frequency greater than 1.0×10^{-6} per year) are equipped with fire detection systems, three of the six dominant fire zones have fire suppression systems, and the Main Control Room, which has neither fire detection or fire suppression systems, is always occupied ensuring prompt fire detection and manual suppression. Entergy stated that no further cost-effective changes were identified to reduce CDF in the dominant fire zones (Entergy 2006b). 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.

The IPEEE analysis of high winds, floods and other external events followed the screening and evaluation approaches specified in Supplement 4 to GL 88-20 (NRC 1991b) and did not identify any sequences or vulnerabilities that exceeded the 1.0×10^{-6} per year criterion (NYPA 1996). However, the licensee identified a condition where low pressures associated with hurricanes, tornadoes, and high winds could threaten the integrity of the air intake duct work supplying the EDG room. Operating procedures were developed to open switchgear room doors or to open damaged duct work if necessary to ensure adequate ventilation of the switchgear room and adequate supply of combustion air to the EDGs. 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 3.1 times the internal events CDF (based on a fire CDF of 8.53×10^{-6} per year and an internal events CDF of 2.74×10^{-6} per year). Accordingly, the total CDF (from internal and external events) would be approximately 4.1 times the internal events CDF. In 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 4 to account for the combined contribution from internal and external events. The NRC staff agrees with the applicant's overall conclusion concerning the impact of external events and concludes that the applicant's use of a multiplier of 4 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, 2007). The current Level 2 model utilizes a single CET containing both phenomenological and systemic events. The Level 1 core damage sequences are binned into one of 48 PDS bins based on binning criteria reflecting the state of the reactor, containment and cooling systems as the accident progresses. The PDSs provide the interface between the Level 1 and Level 2 analysis. CET nodes are evaluated using supporting fault trees and logic rules.

Entergy characterized the releases for the spectrum of possible radionuclide release scenarios using a set of 7 release categories based on the timing and magnitude of the release and whether or not the containment remains intact. The frequency of each release category was obtained by summing the frequency of the individual accident progression CET endpoints binned into the release category. The release characteristics for each release category were developed by grouping the hundreds of source terms generated for internal initiators into the 7 categories based on similar properties. Source term release fractions were developed for each of the 7 release categories using the results of Modular Accident Analysis Program (MAAP 4.0.4) computer code calculations. The release categories, their frequencies, and release characteristics are presented in Tables E.1-8, E.1-10, and E.1-11 of the ER, respectively (Entergy 2006a). These release categories and source terms were further collapsed into three distinct source term bins to represent no containment failure, early releases, and late releases.

The NRC staff noted that in collapsing the 7 release categories into three source term bins, releases occurring between 0 to 8 hours and between 8 to 24 hours were grouped into one bin. In response to an RAI, Entergy performed a sensitivity study that showed that this simplification results in less than a 2 percent change on population dose (Entergy 2007). Based on these results the NRC staff concludes that the applicant's characterization of releases is adequate for the purposes of the SAMA evaluation.

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 1994). It should be noted, however, that the current Level 2 model is a revision to that of the IPE. The Level 2 PSA model was included in the independent consultant and BWROG peer reviews mentioned previously. The changes to the Level 2 model to update the methodology and to address peer review recommendations are described in Section E.1.4.2.2 of the ER. 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, and updated to address the review findings, the NRC staff concludes that the Level 2 PSA provides an acceptable basis for evaluating the benefits associated with various SAMAs.

Entergy used the MACCS2 code and scaled the reference BWR core inventory for the JAFNPP plant-specific power level. Entergy also increased the long-lived radionuclide core inventory by 25 percent to address JAFNPP specific fuel enrichment and burnup. In response to an NRC staff RAI, Entergy identified that the 25-percent increase was based on a best estimate inventory of long-lived isotopes (such as Sr-90, Cs-134 and Cs-137) from an ORIGEN computer code calculation assuming 4.65 percent enrichment and average burnup based on expected fuel management practices (Entergy 2007). The best-estimate evaluation resulted in an increase of approximately 25 percent in the inventories of the aforementioned radionuclides. The NRC staff considers the methods and assumptions for power scaling and 25 percent increase in long-lived inventory reasonable and acceptable for purposes of the SAMA evaluation.

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 a 50-mile radius for the year 2034, emergency evacuation modeling, and economic data. This information is provided in Attachment E to the ER (Entergy 2006a).

Entergy used site-specific meteorological data for the 1994 calendar year as input to the MACCS2 code. The data were collected from the onsite meteorological monitoring system and regional National Weather System (NWS) stations. In response to an NRC staff RAI, Entergy identified the location of the National Weather System stations as being at Fulton-Oswego County Airport and NWS Station No. 14733 in Buffalo, NY (Entergy 2007). Based on a review of meteorological data between 1985 and 2001, Entergy stated that it considered the year 1994 data to be the most representative set of data because it contained no significant extremes and reflected average meteorological conditions at the site (Entergy 2006a). Missing data was obtained from either the upper elevation on the met tower or from estimates based on adjacent valid measurements of the missing hour. 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 1994 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 2034, based on the New York Statistical Information System projections from year 2000 to 2030 (Brown 2005). The 2000 population was adjusted to account for transient population. These data were used to project county-level resident populations to the year 2034 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 2.0 meters per second (4.4 miles per hour) with a delayed start time of 2.25 hours (Entergy 2006a). This assumption is similar to the model used in NUREG-1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the emergency planning zone (EPZ). Sensitivity analyses were performed in which the evacuation delay time was increased to 4.5 hours, and the evacuation speed was decreased to 1.0 meters per second. The results were less than a one percent increase in the total population dose. The NRC staff questioned why the evacuation speed of 2.0 meters per second (4.4 miles per hour) was different than that used for the Nine Mile Point SAMA analysis (NRC 2006). In response, Entergy stated that the JAFNPP evacuation speed was based on evacuation times provided in the 2003 version of the evacuation time study (ETE) (KLD Associates 2003), whereas the Nine Mile Point evacuation time estimate was based on an ETE study performed in 1993 (Entergy 2007). The NRC staff also asked Entergy to address the potential impact on the population dose if 5 percent of the population fails to evacuate the EPZ (NRC 2006). In response, Entergy performed a sensitivity analysis that showed only a slight increase in population dose (less than 1 percent for the late release) would result (Entergy

2007). The NRC staff concludes that the evacuation assumptions and analysis are reasonable and acceptable for the purposes of the SAMA evaluation.

Much of the site-specific economic data was provided from the 2002 Census of Agriculture (USDA 2002). These included the value of farm and non-farm wealth. Other data such as daily cost for an evacuated person, population relocation cost, daily cost for a person who is relocated, cost of farm and non-farm decontamination, and property depreciation were provided from the Code Manual for MACCS2 (NRC 1997c). The data from the default values given in the MACCS2 code manual were adjusted using the consumer price index of 179.9, the average value for 2002. Information on regional crops were obtained from the 2002 Census of Agriculture. Crops for each county were mapped into the seven MACCS2 crop categories.

The NRC staff concludes that the methodology used by Entergy to estimate the offsite consequences for JAFNPP 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 current, plant-specific PSA,
- Review of potential plant improvements identified in the JAFNPP IPE and IPEEE,
- Review of SAMA candidates identified for license renewal applications for six other U.S. General Electric (GE) plants, and
- Review of other NRC and industry documentation discussing potential plant improvements.

Based on this process, an initial set of 293 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 JAFNPP due to design differences,
- The SAMA has already been implemented at JAFNPP, or
- The SAMA is similar in nature and could be combined with another SAMA candidate.

Based on this screening, 230 SAMAs were eliminated leaving 63 for further evaluation. The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table E.2-1 of the ER (Entergy 2006a). In Phase II, a detailed evaluation was performed for each of the 63 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 4, 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 (RRW) perspectives at JAFNPP, and included selected SAMAs from prior SAMA analyses for other plants.

Entergy provided a tabular listing of the PSA basic events sorted according to their RRW (Entergy 2006a). SAMAs impacting these basic events 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 of approximately $2,500 (after the benefits have been multiplied to account for external events). Entergy also provided and reviewed the large early release frequency (LERF)-based RRW events down to a RRW of 1.005. Entergy correlated the top Level 1 and Level 2 events with the SAMAs evaluated in the ER, and showed that all of the significant basic events are addressed by one or more SAMAs (Entergy 2006a).

NRC staff noted that no Phase II SAMAs were recommended for event NR-LOSP-7HR, non-recovery of offsite power in seven hours, which is the highest risk reduction worth non-initiator event. The NRC staff asked the applicant to identify and evaluate SAMAs for this event (NRC 2006). In response to the RAI, Entergy stated that procedure and training improvements for restoring power to vital equipment following a recovery of the offsite power supply have been implemented, but that hardware improvements that could facilitate recovery of offsite power would merely shift NR-LOSP-7HR to a slightly later time on the power recovery curve and therefore would have little impact on the RRW of the event (Entergy 2007). Entergy further noted that other Phase II SAMAs (26 through 36 and 62), if implemented, would reduce the CDF contribution from this basic event. These SAMAs would enhance AC or DC system reliability or otherwise cope with loss of offsite power and SBO events. These Phase II SAMAs were evaluated in the ER.

NRC staff also noted that no Phase I or Phase II SAMAs were recommended for event IE-RRFLOOD, transient caused by internal flooding in the relay room, although a procedure change has been implemented to address the event. In an NRC staff RAI, the applicant was asked to provide justification for why no SAMAs were identified to address internal flooding events (NRC 2006). Entergy responded that additional methods of mitigating this flood event would entail either moving the fire protection line or installing a guard pipe to channel floodwater out of the relay room, both of which were judged to be costly relative to the risk significance of the related flood scenarios (Entergy 2007). The remaining flood scenarios are not risk-significant (i.e., above the 1.005 RRW threshold for SAMA identification).

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 2006). In response to the RAI, Entergy provided the requested information (Entergy 2007).

The NRC staff questioned the ability of some of the candidate SAMAs to accomplish their intended objectives (NRC 2006). 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 2007). 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: the use of a redundant diesel fire pump to address event FXT-ENG-FR-76PI (failure of diesel driven fire pump 76P-1), the use of a local hand wheel or gas bottle supplies for manual venting of containment, and the use of a portable generator to provide alternate DC power feeds (NRC 2006). In supplemental information and 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, 2007). This is discussed further in Section G.6.2.

In the ER, Entergy states that in both the IPE and IPEEE, several enhancements related to severe accident insights were recommended and implemented, and that these enhancements were included in the comprehensive list of Phase I SAMA candidates. However, the list of Phase I SAMA candidates was not provided in the ER. Therefore, the NRC staff requested that the applicant indicate whether the enhancement has been implemented, and whether credit for the enhancement is taken in the current PSA model (used for the SAMA analysis) (NRC 2006). In supplemental information to the ER, Entergy indicated that Phase I SAMAs 253, 256, 262, and 280 through 293 include enhancements recommended in the IPE and IPEEE (Entergy 2006b). Entergy further indicated that most of these SAMAs have been implemented and that SAMA 280 was determined to be unnecessary. Those enhancements that have not been implemented or determined to not be necessary (SAMAs 281 through 284) were retained for consideration during Phase II. In response to the RAI, Entergy noted that except for Phase I

SAMAs 94, 101, 120, and 267, the implemented Phase I SAMAs mentioned in the ER have been credited in the current PSA model (Entergy 2007). The absence of these four implemented modifications from the PSA model adds conservatism to the benefit estimates for Phase II SAMAs.

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

Entergy did not identify JAFNPP-specific candidate SAMAs for seismic events. In the JAFNPP IPEEE seismic analysis, the overall plant HCLPF value was determined to be 0.22g. This value reflects implemented improvements to strengthen block walls EGB-272-6, 7, 9, and 10 in the Emergency Diesel Generator Building, which increased the plant HCLPF value from 0.17g to 0.22g. Several buildings and structures have HCLPF values at the 0.22g level. Thus, further increases in seismic capacity would require multiple plant modifications. The JAFNPP IPEEE also identified that there is a fire-induced seismic vulnerability due to failure of the hydrogen line in the turbine building. The NRC staff requested that the applicant provide details on actions taken to reduce this risk and whether a SAMA to further reduce this risk is cost-beneficial (NRC 2006). In their response, Entergy stated the hydrogen supply is protected by excess flow valves outside the turbine building that are intended to limit hydrogen release in the event of a line break (Entergy 2007). Entergy also indicated that this event has already been further mitigated by making a modification to plant abnormal procedure AOP-14, "Earthquake," to require that plant operators close hydrogen supply valve 89A-H2HAS-1 following a seismic event (Phase I SAMA 286). Finally, Entergy notes that the turbine building fire risk provided in the ER (which does not reflect the implemented plant procedure) is less than 1×10^{-6} per year, and cannot be further reduced in a cost-effective manner. 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 any JAFNPP-specific candidate SAMAs for fire events. The fire risk at JAFNPP is dominated by ten fire areas, eight of which have fire CDF contributions in excess of 1×10^{-6} per year, with the largest contributor being the Cable Spreading Room. 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 2006). In supplemental information to the ER, Entergy stated that the fire area CDFs are conservative and presented the results of a sensitivity analysis that reduced modeling conservatisms (Entergy 2006b). This analysis, as discussed previously in Section G.2.2, reduced the individual CDF contributions for three of the top four dominant fire areas to below the 1×10^{-6} per year threshold. Entergy also noted that the fire CDF is further reduced by IPEEE improvements not included in the CDF estimate, such as restraining or relocating flammables cabinets, monitoring and controlling the quantity of combustible materials in critical process areas, and monitoring and control of pre-staging of outage materials (Phase I SAMAs 287 through 289). These measures would reduce the fire CDF in all dominant fire zones. Therefore, modifications to further reduce the fire CDF are unlikely to be cost-beneficial (Entergy 2006b). Entergy also stated that all but one of the six dominant fire zones are equipped with fire detection systems, three of the six dominant fire zones have fire suppression systems, and the Main Control Room, which has neither fire detection or fire suppression systems, is always occupied ensuring prompt fire detection and manual suppression (Entergy 2006b). Therefore, no cost-effective hardware changes or other modifications were identified.

As stated earlier, other external hazards (high winds, external floods, and transportation and nearby facility accidents) are below the threshold screening frequency and are not expected to impact the conclusions of the SAMA analysis. However, the licensee identified a condition where low pressures associated with hurricanes, tornadoes, and high winds could threaten the integrity of the air intake duct work supplying the EDG room. Operating procedures were developed to open switchgear room doors or to open damaged duct work if necessary to ensure adequate ventilation of the switchgear room and adequate supply of combustion air to the EDGs. No plant modifications were identified for these external hazards. The NRC staff concludes that the applicant's rationale for eliminating fire and other external hazards 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 JAFNPP, 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, and reviewing plant improvements considered in previous SAMA analyses. While explicit treatment of external events in the SAMA identification process was limited, it is recognized that the prior implementation of plant modifications for fire risks and the absence of external event vulnerabilities reasonably justifies examining primarily the internal events risk results for this purpose.

G.4 Risk Reduction Potential of Plant Improvements

Entergy evaluated the risk-reduction potential of the 63 remaining SAMAs that were applicable to JAFNPP. 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 overestimate 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 JAFNPP PSA model. The changes made to the model to quantify the impact of SAMAs are detailed in Section E.2.3 of Attachment E to the ER (Entergy 2006a). Table G-5 lists the assumptions considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The estimated benefits reported in Table G-5 reflect the combined benefit in both internal and external events, as well as a number of changes to the analysis methodology 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 2006). SAMAs 8, 14, and 22 were each modeled by assuming that reactor building failures were completely eliminated, yet the results presented in the ER indicated no reduction in offsite dose. In response to the RAI, Entergy revised the estimated benefit values submitted in the ER for these SAMAs and all other SAMAs which directly impact the CET model and alter the distribution of releases within a release bin (Entergy 2007). In response to this RAI, Entergy also changed the CDF reductions for Phase II SAMAs 11, 16, 17, and 39 to 0 percent to correct erroneous entries in the ER. The CDF reduction values for these SAMAs are now consistent with that for SAMA 25, which resolves another NRC staff RAI questioning that the benefit estimates for these SAMAs should not have been different (NRC 2006). Table G-5 reflects all of these revisions. Revision of these benefit estimates had no impact on the original conclusions.

For SAMA 57, control containment venting within a narrow band of pressure, the staff noted that the analysis assumptions were not directly related to the impact of the SAMA on CDF. In supplemental information to the ER, Entergy described a sensitivity analysis to assure that the benefit values reported for this SAMA are conservative. The sensitivity analysis resulted in a decrease in the assessed benefit; Entergy thus concluded that the benefit values reported in Table S-1 of the supplemental submittal (and in Table G-5) are conservative (Entergy 2006b).

For SAMA 61, develop a procedure to use a portable power supply for battery chargers, the staff noted that the events eliminated in the analysis were not included in the list of risk significant events in ER Table E.1-2. In response to an NRC staff RAI, Entergy reevaluated the benefit by eliminating the failures of both DC battery chargers and both 125-V DC battery control boards, which resulted in an increase in the assessed benefit (Entergy 2007).

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 63 candidate SAMAs through the application of engineering judgment, 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 did not account for inflation. 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.

The NRC staff reviewed the bases for the applicant's cost estimates (presented in Section E.2.3 of Attachment E to the ER), in supplemental information to the ER (Entergy 2006b), and in response to NRC staff RAIs (Entergy 2007). 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 applicant's 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. For those cost estimates that were taken from a dual-unit SAMA analysis, Entergy reduced the estimated costs by half. The staff reviewed the costs and found them to be reasonable, and generally consistent with estimates provided in support of other plants' analyses.

The NRC staff questioned the estimated cost of $400,000 for implementation of SAMA 57, control containment venting within a narrow band of pressure, for what appears to be a procedure and training issue (NRC 2006). In supplemental information to the ER, Entergy further described this modification as requiring detailed engineering studies, potential hardware modifications, procedure changes, simulator changes, and training (Entergy 2006b). Based on this additional information, the NRC staff considers the estimated cost to be reasonable and acceptable for purposes of the SAMA evaluation.

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

Table G-5. SAMA Cost/Benefit Screening Analysis for JAFNPP

SAMA[a]	Assumptions	% Risk Reduction CDF	% Risk Reduction Population Dose	Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
Common cause failures of the SW system	CDF contribution due to common cause failure of ESW pumps was eliminated	1	1	5,000	6,000	
1 – Add a service water pump						5,900,000
Decay Heat Removal Capability – Torus Cooling	Completely eliminate loss of torus cooling mode of RHR system events	8	9	40,000	52,000	
2 – Install an independent method of suppression pool cooling						5,800,000
15 – Dedicated suppression pool cooling						5,800,000
Decay Heat Removal Capability – Drywell Spray	Completely eliminate loss of drywell spray mode of RHR system events	8	9	40,000	51,000	5,800,000
10 – Install a passive containment spray system						

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction: CDF	% Risk Reduction: Population Dose	Total Benefit Using 7% Discount Rate[(b)] ($)	Total Benefit Using 3% Discount Rate[(b)] ($)	Cost ($)
Filtered Vent	Reduce successful torus venting accident progression source terms by a factor of two	0	4	16,000	23,000	
3 – Install a filtered containment vent to provide fission product scrubbing.						1.500.000
Option 1: Gravel bed filter						
Option 2: Multiple venturi scrubber						
20 – Install a filtered vent						1.500.000
Containment Vent for ATWS Decay Heat Removal	Completely eliminate ATWS sequences associated with containment bypass	3	8	28,000	38,000	
4 – Install a containment vent large enough to remove anticipated transient without scram (ATWS) decay heat						>1,000,000
52 – Install an ATWS sized vent						>1,000,000

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction: CDF	% Risk Reduction: Population Dose	Total Benefit Using 7% Discount Rate(b) ($)	Total Benefit Using 3% Discount Rate(b) ($)	Cost ($)
Molten Core Debris Removal(c)	Completely eliminate containment failures due to core-concrete interaction (not including liner failure)	0	64	34,000	48,000	
5 – Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris						>100,000,000
6 – Create a water cooled rubble bed on the pedestal.						19,000,000
9 – Create a core melt source reduction system						>5,000,000
24 – Install a reactor cavity flooding system						8,750,000
Flooding the Rubble Bed(c)	Completely eliminate dry core-concrete interactions	0	22	12,000	16,000	2,500,000
23 – Provide a means of flooding the rubble bed						
Base Mat Melt-Through(c)	Completely eliminate containment failures due to base mat melt-through	0	~0	~0	~0	>5,000,000
12 -Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur						

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
		CDF	Population Dose			
Reactor Vessel Exterior Cooling[c]	Reduce probability of vessel failure by a factor of two	0	3	2,000	2,000	2,500,000
13 – Provide a reactor vessel exterior cooling system						
Drywell Head Flooding	Completely eliminate drywell head failures due to high temperature	0	0	0	0	
7 – Provide modification for flooding the drywell head						>1,000,000
19 – Increase the temperature margin for seals						12,000,000
21 – Provide a method of drywell head flooding						>1,000,000
Reactor Building Effectiveness[c]	Completely eliminate reactor building failures	0	31	17,000	24,000	
8 – Enhance fire protection system and SGTS hardware and procedures						>2,500,000
14 – Construct a building connected to primary containment that is maintained at a vacuum						>1,000,000
22 – Use alternate method of reactor building spray						>2,500,000

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction: CDF	% Risk Reduction: Population Dose	Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
Strengthen Containment[c]	Completely eliminate all energetic containment failure modes (Direct containment heating [DCH], steam explosions, late over-pressurization)	0	28	13,000	19,000	
11 – Strengthen primary and secondary containment						12,000,000
16 – Create a larger volume in containment						8,000,000
17 – Increase containment pressure capability (sufficient pressure to withstand severe accidents)						12,000,000
25 – Add ribbing to the containment shell						12,000,000
Vacuum Breakers	Completely eliminate vacuum breaker failures	~0	7	22,000	31,000	>500,000
18 – Install improved vacuum breakers (redundant valves in each line)						

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction CDF	% Risk Reduction Population Dose	Total Benefit Using 7% Discount Rate(b) ($)	Total Benefit Using 3% Discount Rate(b) ($)	Cost ($)
DC Power	Increase time available to recover offsite power (before HPCI and RCIC are lost) from 14 to 24 hours during SBO scenarios	39	44	209,000	270,000	
26 – Provide additional DC battery capacity						500,000
27 – Use fuel cells instead of lead-acid batteries						>1,000,000
30 – Provide 16-hour SBO injection						500,000
34 – Install fuel cells						>1,000,000
36 – Extended SBO provisions						500,000
Improved DC System						
28-Incorporate an alternate battery charging capability	Completely eliminate loss of DC battery chargers	3	~0	8,000	10,000	90,000
29 – Modification for improving DC bus reliability	Completely eliminate loss of 125 VDC bus B initiator	1	1	5,000	6,000	500,000
61 – power supply for battery chargers(d)	Completely eliminate loss of DC battery chargers and battery control boards	2	2	10,000	13,000	10,000

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction CDF	Population Dose	Total Benefit Using 7% Discount Rate[(b)] ($)	Total Benefit Using 3% Discount Rate[(b)] ($)	Cost ($)
Dedicated DC Power and Additional Batteries and Divisions	Completely eliminate loss of DC battery control board BCB-2A	1	1	5,000	6,000	
32 – Add a dedicated DC power supply						3,000,000
33 – Install additional batteries or divisions						3,000,000
35-Install DC Buss cross-ties.						300,000
Alternate Pump Power Source	Completely eliminate SBO diesel generator failures	1	1	3,000	4,000	>1,000,000
31 – Provide an alternate pump power source						
Locate RHR Inside Containment	Completely eliminate all RHR ISLOCA sequences	1	1	3,000	4,000	>500,000
37 – Locate RHR inside containment						
Interfacing System Loss of Coolant Accident (ISLOCA)	Completely eliminate all ISLOCA events	1	2	7,000	10,000	100,000
38 – Increase frequency of valve leak testing						

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
		CDF	Population Dose			
Main Steam Isolation Valve (MSIV) Design	Completely eliminate containment bypass due to MSIV leakage failures	0	20	9,000	13,000	>1,000,000
39 – Improve MSIV design[c]						
Main Feedwater	Completely eliminate loss of feedwater initiator	1	1	3,000	4,000	
40-Install a digital feedwater upgrade						1,500,000
Backup Water for feedwater/condensate injection						
41-Create ability to connect to existing or alternate water sources to feedwater/condensate	Completely eliminate contribution due to failure of alternate injection from feedwater/condensate	1	1	3,000	4,000	170,000
43-Install motor driven feedwater pump	Completely eliminate the failure of feedwater turbine driven pumps	~0	0	0	0	1,650,000
Diesel to condensate storage tank (CST) Makeup Pumps	Completely eliminate switchover from CST to torus failures	2	~0	2,000	3,000	135,000
42 – Install an independent diesel for the CST makeup pumps						

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction CDF	% Risk Reduction Population Dose	Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
High Pressure Injection System	HPCI system is always available	3	1	8,000	10,000	
44 – Provide an additional high pressure injection pump with independent diesel						>1,000,000
45 – Install independent AC high pressure injection system						>1,000,000
46 – Install a passive high pressure system						>1,000,000
48 – Install an additional active high pressure system						>1,000,000
49 – Add a diverse injection system						>1,000,000
Improve the Reliability of High Pressure Injection System	Reduce HPCI system failure probability by a factor of 3	2	~0	6,000	7,000	
47 – Improved high pressure systems						>1,000,000
Increase reliability of instrument air after loss of offsite power (LOSP)	Reduce probability of failure of normal electric power supply to air compressors by a factor of 10	~0	0	0	0	
50-Modify EOPs for ability to align diesel power to more air compressors						1,200,000

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction: CDF	% Risk Reduction: Population Dose	Total Benefit Using 7% Discount Rate[(b)] ($)	Total Benefit Using 3% Discount Rate[(b)] ($)	Cost ($)
Safey relief valve (SRVs) Reseat	Completely eliminate stuck open SRV events	4	4	18,000	23,000	
51 – Increase SRV reseat reliability						2,200,000
Diversity of Explosive Valves	Completely eliminate common cause failures of SLC explosive valves	~0	0	0	0	
53 – Diversify explosive valve operation						>200,000
Prevent catastrophic containment failure	Reduce CDF contribution in scenarios where containment venting is successful by a factor of 2	2	2	10,000	14,000	
54-Implement passive overpressure relief						>500,000
Improve control rod drive (CRD) reactor vessel injection reliability	Eliminate failure of CRD reactor vessel injection	~0	0	0	0	
55-Change CDR flow control valve failure position to the 'fail-safest" position						>140,000
Large Break LOCA	Completely eliminate large break LOCAs	~0	0	0	0	>100,000
56 – Provide digital large break LOCA protection						

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction CDF	 Population Dose	Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
Controlled Containment Venting	Reduce probability of operator to recognize the need to vent the torus by a factor of 3	14	16	74,000	95,000	400,000
57 – Control containment venting within a narrow band of pressure						
RHR heat removal	Completely eliminate CDF contribution from failure of cross-tie from fie protection to RHR heat exchanger "A"	~0	1	2,000	3,000	
58-Provide tap from fire protection to RHR heat exchanger "B" via RHRSW header B						150,000
Injection and containment heat removal	Complete eliminate failure from residual heat removal service water (RHRSW)loop B	11	12	56,000	73,000	
59- Provide a cross-tie between RHRSW trains downstream of the RHRSW pump discharge valves						400,000
Turbine Bypass	Eliminate CDF contribution due to loss of power conversion system (PCS) initiator	10	7	42,000	52,000	
60-Improve turbine bypass valve capability						745,000

Table G-5. (cont.)

SAMA	Assumptions	% Risk Reduction: CDF	% Risk Reduction: Population Dose	Total Benefit Using 7% Discount Rate[b] ($)	Total Benefit Using 3% Discount Rate[b] ($)	Cost ($)
Emergency Diesel Generators		21	24	116,000	149,000	
62-Develop a procedure to open the doors of the EDG buildings upon receipt of a high temperature alarm	**Reduce probability of EDG to run failures by a factor of three.**					**10,000**
Reactor Vessel Instrumentation	Completely eliminate CDF contribution due to loss of reactor vessel water level reference leg	2	2	7,000	9,000	
63-Provide additional reactor vessel monitoring and actuation system						1,200,000

(a) SAMAs in bold are potentially cost-beneficial

(b) Unless noted otherwise by Footnote (c) or (d), estimated benefits taken from Table S-1 in the supplemental information to the ER (Entergy 2006b)

(c) Estimated benefits taken from a revised assessment provided in response to RAI 5 7 (Entergy 2007)

(d) Estimated benefits taken from a revised assessment provided in response to RAI 5.1 (Entergy 2007)

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 1997a). The guidance involves determining the net value for each SAMA according to the following formula:

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

where

APE = present value of averted public exposure ($)

AOC = present value of averted offsite property damage costs ($)

AOE = present value of averted occupational exposure costs ($)

AOSC = present value of averted onsite costs ($)

COE = cost of enhancement ($)

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and it is not considered cost-beneficial. 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 3 percent and one at 7 percent (NRC 2004).

Averted Public Exposure (APE) Costs

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δperson-rem/year)

× monetary equivalent of unit dose ($2000 per person-rem)

× 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 1997a), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk due to a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the renewal period) of the facility. Thus, it reflects the expected annual loss due to a single accident, the possibility that such an accident could occur at any time over the renewal period, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, which assumes elimination of all severe accidents due to internal events, Entergy calculated an APE of approximately $35,000 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

× offsite economic costs associated with a severe accident (on a per-event basis)

× 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 $3,300 based on the Level 3 risk analysis. This results in a discounted value of approximately $36,000 for the 20-year license renewal period.

Averted Occupational Exposure (AOE) Costs

The AOE costs were calculated using the following formula:

AOE = Annual CDF reduction

× occupational exposure per core damage event

× monetary equivalent of unit dose

× present value conversion factor

Entergy derived the values for averted occupational exposure from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997a). Best estimate values provided for immediate occupational dose (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 $2000 per person-rem, a real discount rate of 7 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 $1,000 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 1997a).

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

× present value of cleanup costs per core damage event

× present value conversion factor

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in the regulatory analysis handbook to be $\$1.5 \times 10^9$ (undiscounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, Entergy calculated an ACC of approximately $32,000 for the 20-year license renewal period.

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

RPC = Annual CDF reduction

× present value of replacement power for a single event

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

× reactor power scaling factor

For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, Entergy calculated an RPC of approximately $22,000 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 from internal events at JAFNPP to be about $125,000. Use of a multiplier of 4 to account for external events increases the value to $500,000 and represents the dollar value associated with completely eliminating all internal and external event severe accident risk at JAFNPP.

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 a 7 percent discount rate, and considering the combined impact of both external events and uncertainties), Entergy identified five potentially cost-beneficial SAMAs. The potentially cost-beneficial SAMAs are:

- SAMA 26 – provide additional DC battery capacity to ensure longer battery capability during the station blackout event, which would extend HPCI/RCIC operability and allow more time for AC power recovery.
- SAMA 30 – modify plant equipment to provide 16-hour SBO injection to improve capability to cope with longer SBO scenarios.
- SAMA 36 – modify plant equipment to extend DC power availability in an SBO event, which would extend HPCI/RCIC operability and allow more time for AC power recovery.

- SAMA 61 – modify plant procedures to allow use of a portable power supply for battery chargers, which would improve the availability of the DC power system.

- SAMA 62 – modify plant procedures to open the doors of the EDG buildings upon receipt of a high temperature alarm, which improves the reliability of the EDGs following high temperatures in the EDG buildings.

Entergy performed additional analyses to evaluate the impact of alternative discount rates and remaining plant life on the results of the SAMA assessment. No additional SAMA candidates were determined to be potentially cost-beneficial (Entergy 2006a). In supplemental information to the ER, Entergy provided a revised assessment based on a separate accounting of uncertainties. The revised assessment resulted in identification of the same potentially cost-beneficial SAMAs. However, based on further consideration of potentially cost-beneficial SAMAs at other plants, Entergy identified one additional potentially cost-beneficial SAMA for JAFNPP (Entergy 2006b). 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 1997a) and was conducted 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 uncertainty. The impact of external events was considered by applying a multiplier of 4.1 to the estimated SAMA benefits in internal events (1 + [fire CDF of 8.53×10^{-6} per year] / [internal events CDF of 2.74×10^{-6} per year]). The impact of uncertainties was considered by applying an additional multiplier of 3.83, which represents the ratio of the 95th percentile CDF to the mean CDF for internal events. Entergy bounded the combined impact of external events and uncertainties by applying a multiplier of 16 to the estimated SAMA benefits in internal events.

In an RAI, 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 2006). In supplemental information to the ER, Entergy revised the baseline benefit values by applying a multiplier of 4 to the estimated SAMA benefits in internal events to account for potential SAMA benefits in both internal and external events (Entergy 2006b).

As a result of the revised baseline analysis (using a multiplier of 4 and a 7 percent real discount rate), Entergy found that the same five SAMA candidates (mentioned above) remained potentially cost-beneficial. No additional SAMA candidates were found to be potentially 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 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 3.83 times the mean CDF. Entergy re-examined the Phase II SAMAs to determine if any would be potentially cost-beneficial if the revised baseline benefits were increased by an additional factor of 4. No additional SAMAs were identified.

The NRC staff questioned the ability of several of the candidate SAMAs identified in the ER to accomplish their intended objectives or provide the estimated risk reductions (NRC 2006). In response to the RAI, Entergy provided revised or new evaluations as discussed below.

- Phase II SAMA 57, control containment venting within a narrow pressure band, was identified as a potential SAMA to further reduce the risk contribution from basic event NVP-XHE-FO-LVENT, operator fails to vent containment using the direct torus vent. This SAMA would be subject to the same failure-to-vent human error as in the basic event. The NRC staff questioned both the risk reduction estimate provided by Entergy for this SAMA, as well as whether an alternative SAMA to create a passive vent system might be more effective in reducing the risk from this event and be cost-beneficial (NRC 2006).

  In the ER, Entergy estimated the benefit of controlling containment venting within a narrow pressure band by reducing the probability of operator failure to vent by a factor of 3. In supplemental information to the ER, Entergy included a sensitivity analysis in which continued vessel injection from LPCI or Core Spray was credited for those sequences in which torus venting is successful and alternative injection systems fail after torus venting (Entergy 2006b). Since the available net positive suction head (NPSH) is likely to be less than the required NPSH with the vent open, a failure probability of 0.9 was assigned for this new success path. The PSA model change resulted in about a 0.5-percent reduction in CDF, a 0.6-percent reduction in population dose, and a benefit (including the impact of uncertainties) of approximately $10,000. Entergy concluded that the original benefit values reported for SAMA 57 (and reported in Table G-5) are more conservative (Entergy 2006b). Therefore, this SAMA continues to not be cost-beneficial at JAFNPP.

  The NRC staff also asked the applicant to provide an evaluation of the costs and benefits of converting the vent system to a passive design. In response, Entergy evaluated a new SAMA that would convert the existing torus vent to a passive torus vent (Entergy 2007). The benefit of this SAMA was conservatively estimated by removing operator failure to implement torus venting (NVP-XHE-FO-LVENT was set to zero). Entergy estimated that this modification would result in a CDF reduction of about

18 percent, a population dose reduction of about 20 percent, and a benefit (7 percent baseline with uncertainty) of approximately $377,000. However, Entergy estimated the cost of implementing this SAMA to be greater than $1M. Therefore, this SAMA alternative would not be cost-beneficial at JAFNPP.

- Phase II SAMA 61, develop a procedure to use a portable power supply for battery chargers, was identified as a potential SAMA to improve DC system reliability. The staff questioned the risk reduction estimate provided by Entergy for this SAMA since the events identified as being eliminated for the analysis were not included in the list of risk significant events in ER Table E.1-2. In response to an NRC staff RAI, Entergy performed a revised evaluation by eliminating failures of both DC battery chargers and both 125-V DC battery boards. The PSA model change resulted in about a 2-percent reduction in CDF, a 2-percent reduction in population dose, and a benefit (including the impact of uncertainties) of approximately $40,000. Entergy concluded that this SAMA remains potentially cost-beneficial (Entergy 2007).

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. Several of these alternatives were evaluated by Entergy subsequent to the ER, and described in the supplemental information to the ER (Entergy 2006b). One such alternative involves use of a portable generator to extend the coping time in loss of AC power events (to power battery chargers). Based on a bounding analysis in which the probability of non-recovery of offsite power for 7 hours was changed to 24 hours for SBO scenarios, this alternative was estimated to result in a CDF reduction of about 39 percent, a population reduction of 44 percent, and a benefit (including impact of uncertainties) of $838,000. Since the estimated cost of implementing and using the portable generator is $712,000, Entergy concluded that this SAMA is potentially cost-beneficial to JAFNPP.

The NRC staff asked the applicant to evaluate several additional lower cost alternatives to the SAMAs considered in the ER. These alternatives included: (1) use a portable generator to provide alternate DC feed to panels supplied only by the DC bus, (2) addition of a redundant diesel fire pump to address event FXT-ENG-FR-76P1, diesel driven fire water pump 76P-1 fails to continue to run (an alternative to SAMA 49, which involves addition of an entire new injection system), and (3) several additional alternatives (NRC 2006). Entergy provided a further evaluation of these alternatives, as summarized below.

- Use of a portable generator to provide power to an individual 125 VDC Motor Control Center (MCC), which would support returning HPCI to service in the event its bus was to fail -- Based on a bounding analysis in which failure of the HPCI system was eliminated, this alternative was estimated to result in a CDF reduction of about 3 percent, a population dose reduction of 1 percent, and a benefit (including impact of uncertainties) of $34,000 (Entergy 2006b). However, Entergy estimated the cost of implementing this alternative to be approximately $700K. Therefore, this alternative would not be cost-beneficial at JAFNPP.

- Use of a third redundant diesel fire pump to address event FXT-ENG-FR-76PI -- Based on a bounding analysis in which events FXT-EG-FR-76PI and FPS-MAI-MA-P4 are set to zero in the PSA model, this alternative was estimated to result in a CDF reduction of about 1 percent, a population dose reduction of 1 percent, and a benefit (including the impact of uncertainties) of $20,000. However, Entergy estimated the cost of implementing this alternative to be approximately $2M (Entergy 2007). Therefore, this alternative would not be cost-beneficial at JAFNPP.

- Entergy indicated that the remaining low cost alternatives identified in the RAI are already implemented or already addressed by existing plant procedures.

In response to an NRC staff RAI, Entergy indicated that the five potentially cost-beneficial SAMAs identified in the ER plus the one additional potentially cost-beneficial SAMA identified in the supplemental information to the ER have all been entered into the licensee's engineering request process to be evaluated for implementation (Entergy 2007). SAMAs 26, 30, 36 and the one additional SAMA were combined into a single engineering request to determine and implement the best approach to extend station battery capacity. SAMA 61 has been approved as a minor modification and is scheduled for installation for late 2007. SAMA 62 was implemented in November 2006 by revising applicable annunciator response procedures.

The NRC staff notes that all of the potentially cost-beneficial SAMAs identified in either Entergy's baseline analysis or uncertainty analysis are included within the set of SAMAs that Entergy plans to further evaluate. The NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the other SAMAs evaluated would be higher than the associated benefits.

G.7 Conclusions

Entergy compiled a list of 293 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. A qualitative screening removed SAMA candidates that (1) were not applicable at JAFNPP due to design differences, (2) had already been implemented at JAFNPP, or (3) were similar and could be combined with another SAMA. Based on this screening, 230 SAMAs were eliminated leaving 63 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 showed that five of the SAMA candidates were potentially cost-beneficial in the baseline analysis (Phase II SAMAs 26, 30, 36, 61, and 62). Entergy performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. No additional SAMAs were identified as potentially cost-beneficial in the ER. However, as a result of additional analysis, Entergy concluded that one additional SAMA is potentially cost-beneficial, i.e., use of a portable generator to extend the coping time in loss of AC power events. Entergy has indicated that the potentially cost-beneficial SAMAs have been entered into the engineering request process to be evaluated for implementation. The NRC staff concluded that all of these SAMAs are potentially cost-beneficial.

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 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

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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 FitzPatrick, LLC, and Entergy Nuclear Operations, Inc. (Entergy) to renew the operating license for James A. FitzPatrick Nuclear Power Plant for an additional 20 years under 10 CFR Part 54. This final 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 NRC 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 JAFNPP are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable. This recommendation is based on (1) the analysis and findings in the GEIS; (2) the Environmental Report submitted by Entergy; (3) consultation with Federal, State, and local agencies; (4) the staff's own independent review; and (5) the staff's consideration of public comments received during the scoping process and on the draft SEIS.

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