5.0 Environmental Impacts of Postulated Accidents

Environmental issues associated with postulated accidents are discussed in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), NUREG-1437, Volumes 1 and 2 (NRC 1996, 1999a).[(a)] The GEIS included a determination of whether the analysis of the environmental issue could be applied to all plants and whether additional mitigation measures would be warranted. Issues were assigned a Category 1 or a Category 2 designation. As set forth in the GEIS, Category 1 issues are those that meet all of the following criteria:

(1) The environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic.

(2) Single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent fuel disposal).

(3) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

For issues that meet the three Category 1 criteria, no additional plant-specific analysis is required unless new and significant information is identified.

Category 2 issues are those that do not meet one or more of the criteria for Category 1, and therefore, additional plant-specific review of these issues is required.

This chapter describes the environmental impacts from postulated accidents that might occur during the license renewal term.

5.1 Postulated Plant Accidents

Two classes of accidents are evaluated in the GEIS. These are design-basis accidents (DBAs) and severe accidents, as discussed below.

(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 Addendum 1.

Design-Basis Accidents

In order to receive approval from the U.S. Nuclear Regulatory Commission (NRC) to operate a nuclear power facility, an applicant must submit a safety analysis report (SAR) as part of its application. The SAR presents the design criteria and design information for the proposed reactor and comprehensive data on the proposed site. The SAR also discusses various hypothetical accident situations and the safety features that are provided to prevent and mitigate accidents. The NRC staff reviews the application to determine whether the plant design meets the Commission's regulations and requirements and includes, in part, the nuclear plant design and its anticipated response to an accident.

DBAs are those accidents that both the licensee and the NRC staff evaluate to ensure that the plant can withstand normal and abnormal transients, and a broad spectrum of postulated accidents without undue hazard to the health and safety of the public. A number of these postulated accidents are not expected to occur during the life of the plant but are evaluated to establish the design basis for the preventive and mitigative safety systems of the facility. The acceptance criteria for DBAs are described in 10 CFR Part 50 and 10 CFR Part 100.

The environmental impacts of DBAs are evaluated during the initial license process, and the ability of the plant to withstand these accidents is demonstrated to be acceptable before issuance of the operating license (OL). The results of these evaluations are found in license documentation such as the applicant's Final Safety Analysis Report (FSAR), the staff's Safety Evaluation Report (SER), and the Final Environmental Statement (FES). The licensee is required to maintain the acceptable design and performance criteria throughout the life of the plant including any extended-life operation. The consequences for these events are evaluated for the hypothetical maximum exposed individual; as such, changes in the plant environment will not affect these evaluations. Because of the requirements that continuous acceptability of the consequences and aging management programs be in effect for license renewal, the environmental impacts as calculated for DBAs should not differ significantly from initial licensing assessments over the life of the plant, including the license renewal period. Accordingly, the design of the plant relative to DBAs during the extended period is considered to remain acceptable and the environmental impacts of those accidents were not examined further in the GEIS.

The Commission has determined that the environmental impacts of DBAs are of SMALL significance for all plants because the plants were designed to successfully withstand these accidents. Therefore, for the purposes of license renewal, design-basis events are designated as a Category 1 issue in 10 CFR Part 51, Subpart A, Appendix B, Table B-1. The early resolution of the DBAs make them a part of the current licensing basis of the plant; the current licensing basis of the plant is to be maintained by the licensee under its current license and, therefore, under the provisions of 10 CFR 54.30, is not subject to review under license renewal. The issue applicable to Catawba is listed in Table 5-1.

Table 5-1. Category 1 Issue Applicable to Postulated Accidents During the Renewal Term

ISSUE—10 CFR Part 51, Subpart A, Appendix B, Table B-1	GEIS Sections
POSTULATED ACCIDENTS	
Design-basis accidents (DBAs)	5.3.2; 5.5.1

Based on information in the GEIS, the Commission found that

> The NRC staff has concluded that the environmental impacts of design basis accidents are of small significance for all plants.

Duke Energy Corporation (Duke) stated in its Environmental Report (ER; Duke 2001a) that it is not aware of any new and significant information associated with the renewal of the OLs for Catawba Nuclear Station, Units 1 and 2 (Catawba). The staff has not identified any significant new information during its independent review of the Catawba ER, the staff's site visit, the scoping process, or its evaluation of other available information. Therefore, the staff concludes that there are no impacts related to this issue beyond those discussed in the GEIS.

Severe Accidents

Severe nuclear accidents are those that are more severe than DBAs because they could result in substantial damage to the reactor core, whether or not there are serious offsite consequences. In the GEIS, the staff assessed the impacts of severe accidents during the license renewal period, using the results of existing analyses and site-specific information to conservatively predict the environmental impacts of severe accidents for each plant during the renewal period.

Severe accidents initiated by external phenomena such as tornadoes, floods, earthquakes, and fires have not traditionally been discussed in quantitative terms in FESs and were not specifically considered for the Catawba site in the GEIS (NRC 1996). However, in the GEIS, the staff did evaluate existing impact assessments performed by NRC and by the industry at 44 nuclear plants in the United States and concluded that the risk from beyond design-basis earthquakes at existing nuclear power plants is SMALL. Additionally, the staff concluded that the risks from other external events are adequately addressed by a generic consideration of internally initiated severe accidents.

Based on information in the GEIS, the Commission found that

> The probability-weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to groundwater, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives.

Therefore, the Commission has designated mitigation of severe accidents as a Category 2 issue in 10 CFR Part 51, Subpart A, Appendix B, Table B-1. The issue applicable to Catawba is listed in Table 5-2.

Table 5-2. Category 2 Issue Applicable to Postulated Accidents During the Renewal Term

ISSUE—10 CFR Part 51, Subpart A, Appendix B, Table B-1	GEIS Sections	10 CFR 51.53(c)(3)(ii) Subparagraph	SEIS Section
POSTULATED ACCIDENTS			
Severe Accidents	5.3.3; 5.3.3.2; 5.3.3.3; 5.3.3.4; 5.3.3.5; 5.4; 5.5.2	L	5.2

The staff has not identified any significant new information with regard to the consequences from severe accidents during its independent review of the Catawba ER, the staff's site visit, the scoping process, or its evaluation of other available information. Therefore, the staff concludes that there are no impacts of severe accidents beyond those discussed in the GEIS. However, in accordance with 10 CFR 51.53(c)(3)(ii)(L), the staff has reviewed severe accident mitigation alternatives (SAMAs) for Catawba. The results of its review are discussed in Section 5.2.

5.2 Severe Accident Mitigation Alternatives

10 CFR 51.53(c)(3)(ii)(L) requires that license renewal applicants consider alternatives to mitigate severe accidents if the staff has not previously evaluated SAMAs for the applicant's plant in an environmental impact statement (EIS) or related supplement or in an environmental assessment. The purpose of this consideration is to ensure that plant changes (i.e., hardware, procedures, and training) with the potential for improving severe accident safety performance are identified and evaluated. SAMAs have not been previously considered for Catawba; therefore, the remainder of Chapter 5 addresses those alternatives.

5.2.1 Introduction

Duke submitted an assessment of SAMAs for Catawba as part of the ER (Duke 2001a). The assessment was based on Revision 2b of the Catawba Probabilistic Risk Assessment (PRA) (Duke 2001b), which is a full scope Level 3 PRA that includes the analysis of both internal and external events. The internal events analysis is an updated version of the Individual Plant Examination (IPE) model (Duke Power Company 1992), and the external events analysis is based on the Individual Plant Examination for External Events (IPEEE) model (Duke Power Company 1994). In identifying and evaluating potential SAMAs, Duke took into consideration the insights and recommendations from the Catawba PRA, as well as other studies, such as the Severe Accident Mitigation Design Alternative (SAMDA) analysis for Watts Bar (NRC 1995a) and NUREG-1560 (NRC 1997c). In the ER, Duke concluded that none of the candidate SAMAs evaluated were cost-effective for Catawba.

After reviewing Duke's SAMA assessment, the staff issued a request for additional information (RAI) to Duke by letter dated November 19, 2001 (NRC 2001). Key questions concerned (1) further information on several candidate SAMAs, especially those that mitigate the consequences of a station blackout (SBO) event; (2) details on the PRA used for the SAMA analysis, including results as they pertain to containment failure and releases; and (3) the impact of including elements of averted risk that were omitted in the ER. Duke submitted additional information by a letter dated February 1, 2002 (Duke 2002a), which provided details on the updated PRA, the requested PRA results, and other information identified in the RAI (NRC 2001). Duke provided additional information in a telephone conference call with the staff on February 25, 2002 (NRC 2002a). In these responses, Duke included supplemental tables showing the impacts of including averted replacement power costs for SAMAs that have the potential to reduce core damage frequencies and averted offsite property damage costs for SAMAs that have the potential to improve containment performance – both of which were omitted in the original analysis. Also, Duke presented its position on the value of providing back-up hydrogen control capability during SBO events. Duke's responses addressed the staff's concerns and reaffirmed that none of the SAMAs would be cost-beneficial. However, based on review of the cost and benefit information provided by Duke, the staff concludes that two SAMAs are cost-beneficial under the assumptions presented. One cost-beneficial SAMA involves plant and procedure modifications to enable the existing hydrogen control (igniter) system to be powered from an ac-independent power source in SBO events. Duke has not implemented this SAMA at Catawba; this issue is currently being addressed by the NRC as part of the resolution of Generic Safety Issue 189 - Susceptibility of Ice-Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident (NRC 2002b). The other cost-beneficial SAMA involves installing a watertight wall around the 6900/4160 V transformers in the basement of the turbine building. Duke has not implemented this SAMA at Catawba; this issue has been identified for follow-up as a current operating plant issue at Catawba. By letter dated August 8, 2002, Duke committed to designing and scheduling the installation of flood protection for the 6900/4160 V transformers (Duke 2002c).

The staff's assessment of SAMAs for Catawba follows.

5.2.2 Estimate of Risk for Catawba, Units 1 and 2

Duke's estimates of offsite risk at Catawba are summarized below. The summary is followed by the staff's review of Duke's risk estimates.

5.2.2.1 Duke's Risk Estimates

The Catawba PRA model, which forms the basis for the SAMA analysis, is a Level 3 risk analysis; that is, it includes the treatment of core damage frequency, containment performance, and offsite consequences. The model, which Duke refers to as PRA, Revision 2b (Duke 2001b), consists of an internal events analysis based on an updated version of the original IPE (Catawba PRA, Revision 1; Duke Power Company 1992) and an external events analysis based on the current version of the IPEEE (Duke Power Company 1994). The calculated total core damage frequency (CDF) for internal and external events in Revision 2b of the Catawba PRA is 5.8×10^{-5} per year.

The Catawba PRA is a "living" PRA. The original version of the IPE has been updated to reflect various design and procedural changes, such as those related to the improvements identified in the IPE and to reflect operational experience. The CDF for internal and external events was reduced from 7.8×10^{-5} per year (Revision 1) to 5.8×10^{-5} per year (Revision 2b). The Level 1 PRA changes associated with the Catawba PRA Revision 2b model included:

- incorporation of updated data for component reliability, unavailabilities, initiating event frequencies, common cause failures, and human error probabilities
- conversion from a sequence-based solution to a single-top fault tree
- modifications to reflect changes to the plant configuration.

The most significant plant enhancement incorporated was providing back-up cooling to one of the two high-head charging pumps. In an event in which normal cooling to the high-head charging pumps is lost, a means to provide back-up cooling from the drinking water supply was implemented to reduce the likelihood of a reactor coolant pump seal loss-of-coolant accident (LOCA). Another important change occurred in the interfacing systems LOCA (ISLOCA) evaluation. The generic database adopted for the Revision 2b analysis had significantly higher failure rates for valve ruptures. This resulted in a significant increase in the CDF contributed by the ISLOCA, an important risk contributor.

The breakdown of the CDF from Revision 2b to the PRA is provided in Table 5-3. Internal event initiators represent about 80 percent of the total CDF and are composed of transients (24 percent of total CDF), LOCAs (29 percent of total CDF), internal flood (24 percent of total CDF), and reactor pressure vessel rupture (2 percent of total CDF). Remaining contributors together account for less than 3 percent of total CDF. External event initiators represent about 20 percent of the total CDF and are composed of seismic initiators (15 percent of total CDF), tornado initiators (4 percent of total CDF), and fire initiators (2 percent of the total CDF). Although not explicitly reported in Table 5-3, SBO events account for 43 percent of the total CDF for internal and external events in Revision 2b of the PRA (Duke 2002a).

Table 5-3. Catawba Core Damage Frequency (Revision 2b of PRA)

Initiating Event	Frequency (per year)	Percent of Total CDF
Transients	1.4×10^{-5}	24
Loss-of-coolant accident (LOCA)	1.7×10^{-5}	29
Internal flood	1.4×10^{-5}	24
Anticipated transient without scram (ATWS)	3.0×10^{-7}	<1
Steam generator tube rupture (SGTR)	3.6×10^{-8}	<1
Reactor pressure vessel rupture	1.0×10^{-6}	2
Interfacing system LOCA (ISLOCA)	2.5×10^{-7}	<1
CDF from internal events	$\mathbf{4.7 \times 10^{-5}}$	**81**
Seismic	8.5×10^{-6}	15
Tornado	2.1×10^{-6}	4
Fire	1.2×10^{-6}	2
CDF from external events	$\mathbf{1.1 \times 10^{-5}}$	**19**
Total CDF	$\mathbf{5.8 \times 10^{-5}}$	**100**

The Level 2 (also called containment performance) portion of the Catawba PRA model, Revision 2b, is essentially the same as the IPE Level 2 analysis. However, the following changes were made:

- modification of the containment event tree (CET) logic regarding the potential for corium contact with the containment liner

- recognition that the refueling water storage tank inventory would drain through a failed reactor vessel in some sequences (e.g., SBO); this was factored into the CET logic.

These changes resulted in a slight increase in the potential for early containment failure as a result of corium contact with the containment liner and a reduction in basemat melt-through due to reactor cavity flooding via the reactor vessel breach.

The offsite consequences and economic impact analyses (i.e., Level 3 PRA Analyses) were carried out using the NRC-developed MELCOR Accident Consequence Code System 2 (MACCS2) code. Inputs for this analysis include plant and site-specific input values for core radionuclide inventory, source term and release fractions, meteorological data, projected population distribution, and emergency response evacuation modeling.

Duke estimated the dose to the population within 80 km (50 mi) of the Catawba site from all initiators (internal and external) to be 0.314 person-sieverts (Sv) (31.4 person-rem) per year (Duke 2001a). The breakdown of the total population dose by containment end-state is summarized in Table 5-4. Internal events account for approximately 0.21 person-Sv

Table 5-4. Breakdown of Population Dose by Containment End-State (Total dose = 0.314 person-Sv [31.4 person-rem] per year)

Containment End State	Percent of Total Dose – Internal Initiators	Percent of Total Dose – External Initiators	Percent of Total Dose – All Initiators
STGR[(a)]	0.2	<0.1	0.2
ISLOCA[(a)]	8.3	0.0	8.3
Containment isolation failure	<0.1	1.0	1.0
Early containment failure	13.2	9.9	23.1
Late containment failure	45.1	22.1	67.2
Basemat melt-through	<0.1	<0.1	<0.1
No containment failure	0.1	<0.1	0.1
Total	**66.9**	**33.1**	**100**

(a) Containment bypass events

(21.0 person-rem) per year, and external events account for approximately 0.104 person-Sv (10.4 person-rem) per year. As can be seen from this table, early and late containment failures account for the majority of the population dose.

5.2.2.2 Review of Duke's Risk Estimates

Duke's determination of offsite risk impacts at Catawba is based on the Revision 2b of the Catawba PRA and a separate MACCS2 analysis. For the purposes of this review, the staff considered the Catawba study in terms of the following major elements:

- the Level 1 and 2 risk models that form the bases for the September 1992 IPE submittal (Duke Power Company 1992)

- the major modifications to the IPE models that have been incorporated in Revision 2b of the PRA (Duke 2001b)

- the external events models that form the basis for the June 1994 IPEEE submittal (Duke Power Company 1994)

- the analyses performed to translate fission product release frequencies from the Level 2 PRA model into offsite consequence measures (Duke 2001a).

The staff reviewed each of these analyses to determine the acceptability of Duke's risk estimates for the SAMA analysis, as summarized below.

The staff's review of the Catawba IPE is described in a staff report dated June 7, 1994 (NRC 1994). In that review, the staff evaluated the methodology, models, data, and assumptions used to estimate the CDF and characterize containment performance and fission product releases. The staff concluded that Duke's analysis met the intent of Generic Letter 88-20 (NRC 1988), which means the IPE was of adequate quality to be used to look for design or operational vulnerabilities. The staff's review primarily focused on the licensee's ability to examine Catawba for severe accident vulnerabilities and not specifically on the detailed findings or quantification estimates. Overall, the staff concluded that the Catawba IPE was of adequate quality to be used as a tool in searching for areas with high potential for risk reduction and to assess such risk reductions, especially when the risk models are used in conjunction with insights, such as those from risk importance, sensitivity, and uncertainty analyses.

The staff's review of the Catawba IPEEE is described in a safety evaluation report dated April 12, 1999 (NRC 1999b). Duke did not identify any fundamental weaknesses or vulnerabilities to severe accident risk with regard to the external events. In the safety evaluation report, the staff concluded that the IPEEE met the intent of Supplement 4 to Generic Letter 88-20 (NRC 1991), and that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities.

The staff reviewed the process used by Duke to extend the containment performance (Level 2) portion of the IPE to the offsite consequence (Level 3) assessment. This included consideration of the source terms used to characterize fission product releases for each containment release category and the major input assumptions used in the offsite consequence analyses. This information is provided in Section 6.3 of Duke's IPE submittal. Duke used the Modular Accident Analysis Program (MAAP) code to analyze postulated accidents and develop radiological source terms for each of 29 containment release categories used to represent the containment end-states. These source terms were incorporated as input to the MACCS2 analysis. The staff reviewed Duke's source term estimates for the major release categories and found these predictions to be in reasonable agreement with estimates of NUREG-1150 (NRC 1990) for the closest corresponding release scenarios. The staff concludes that the assignment of source terms is acceptable.

The plant-specific input to the MACCS2 code includes the Catawba reactor core radionuclide inventory, emergency response evacuation modeling based on Catawba evacuation time estimate studies, release category source terms from the Catawba PRA, Revision 2b, analysis (same as the source terms used in the IPE), site-specific meteorological data, and projected population distribution within a 80-km (50-mi) radius for the year 2040.

MACCS2 requires a file of hourly meteorological data consisting of wind speed, wind direction, atmospheric stability category, and precipitation. For the Catawba SAMA analysis, the meteorological data was obtained from the meteorological tower located on the Catawba site; the meteorological data used in MACCS2 contained data for one year, January 1 through December 31, 1991.

The Catawba PRA, Revision 2b, and the SAMA offsite consequence analyses use three distinct evacuation schemes in order to adequately represent evacuation time estimates for the permanent resident population, the transient population, and the special facility population (schools, hospitals, etc.). The three groups are defined by the time delay from initial notification to start of evacuation. For each evacuation scheme, the fraction of the population starting their evacuation is included. For the permanent resident evacuation schemes, it was assumed that 5 percent of the population would delay evacuation for 24 hours after being warned to evacuate. The delay time and fraction of population for the remaining two schemes was developed from information given in the latest update to the Catawba evacuation time estimate study for the 10-mile Emergency Planning Zone (EPZ). The evacuation schemes include additional information such as evacuation distance, average evacuation speed, sheltering, and shielding considerations. In the Catawba evacuation model, only the 10-mile EPZ is assumed to be involved in the initial evacuation. The MACCS2 model assumes that persons outside of the 10-mile EPZ will wait 24 hours before evacuating (provided that radiological conditions warrant evacuation).

The staff reviewed the Duke responses (Duke 2002a) to questions regarding meteorological data, population data, and emergency planning. The responses confirmed that Duke used appropriate values for the consequence analysis.

The staff also reviewed the Duke responses (Duke 2002a) to questions regarding the low frequency of steam generator tube ruptures (SGTR) accidents (3.6×10^{-8} per year). Duke explained the low value as largely due to the use of IPE success criteria, under which sequences are categorized as successes if core damage occurs beyond 24 hours, an assumption not in accordance with current, generally accepted industry practice. Duke indicated that the next revision of the Catawba PRA will reflect this correction. The staff notes that the impact of this correction can be sizable, as demonstrated in Duke's revision to the McGuire PRA, in which the frequency of SGTR accidents increased by a factor of 600 (NRC 2002d). However, even with the higher SGTR frequency, the maximum benefit associated with completely eliminating SGTR events at McGuire was estimated to be about $100,000 (present worth for the 20-year license renewal period). Previous analyses of severe accidents mitigation alternatives (e.g., for advanced light water reactors) have shown that implementation costs for alternatives to prevent or mitigate SGTR events would be expensive (on the order of several million dollars). The staff concludes it is unlikely that a cost-beneficial alternative could be implemented to substantially reduce SGTR risk given the low expected benefits and the high implementation costs.

The staff concludes that the methodology used by Duke to estimate the CDF and offsite consequences for Catawba provides an acceptable basis from which to proceed with an assessment of the risk reduction potential for candidate SAMAs. Additionally, the risk profile used is similar to other PWRs with ice-condenser containments. Accordingly, the staff bases its assessment of offsite risk on the CDF and population doses reported by Duke.

5.2.3 Potential Design Improvements

This section discusses the process for identifying potential design improvements, the staff's evaluation of this process, and the design improvements evaluated in detail by Duke.

5.2.3.1 Process for Identifying Potential Design Improvements

Duke's process for identifying potential plant improvements consisted of the following elements:

- The core damage cut sets from Revision 2b of the Catawba PRA were reviewed to identify potential SAMAs that could reduce CDF.

- The Fussell-Vesely (F-V) importance measures were evaluated for the basic events (including initiating events, random failure events, human error events, and maintenance/testing unavailabilities), and the importance ranking was examined to identify any events of significant F-V importance.

- Potential enhancements to reduce containment failure modes of concern for Catawba (including early containment failure, containment isolation failure, and containment bypass) were reviewed for possible implementation.

In addition, Duke reviewed the Watts Bar SAMDA analysis (NRC 1995a), and insights from the staff's generic report on the IPE (NRC 1997c) to identify additional SAMAs.

As a starting point for the core damage cut set review, Duke developed a listing of the top 100 cut sets (severe accident sequences) based on internal initiators and the top 100 cut sets for external initiators. These 200 sequences include all potential core damage sequences with at least a 0.08 percent contribution to the total CDF. Additionally, some cut sets contributing as little as 0.01 percent to the total CDF were considered. Duke reviewed the cut sets to identify potential SAMAs that could reduce CDF. A cutoff value of 5.8×10^{-7} per year (for internal and external event initiators) was used to screen events. To account for the cumulative effect of cut sets below this cutoff value, the basic events importance measure was also used to identify potential enhancements, as discussed below. Duke indicated in response to the requests for additional information (RAIs) that the estimated CDF for the 200 cut sets is 4.1×10^{-5} per year, which is about 71 percent of the total CDF (Duke 2002a).

For each seismic initiator cut set, Duke calculated the associated offsite risk based on the population dose and CDF for the plant damage states (PDSs) attributable to the seismic initiator. Duke conservatively assumed that the implementation of plant enhancements for seismic events would completely eliminate the seismic risk and calculated the present worth of the averted risk based on a $2000 per person-rem ($200,000 per person-Sv) conversion factor, a discount factor of 7 percent, and a 20-year license renewal period. This process was repeated for each of the remaining seismic initiator cut sets above the cutoff frequency. The present worth of averted risk for all of the seismic cut sets combined was estimated to be about $316,000 (not including the cost of replacement power and offsite property damage, the significance of which is discussed in Section 5.2.6.2). On the basis of the small risk reduction achievable (0.08 person-Sv [8.0 person-rem]) and the large costs associated with substantial seismic upgrades (estimated at several million dollars), Duke eliminated seismic SAMAs from further consideration.

Duke reviewed the F-V Basic Event Importance Ranking presented in the Catawba PRA report, Revision 2b, and identified several basic events for further consideration. These included seismic-related events, initiating events, equipment failures, and human-error events. Seismic-related events were not evaluated further for reasons discussed above. Five potential enhancements for reducing CDF were identified through this process and are presented in Table 5-5.

In the ER, Duke stated that two design options – installing a watertight wall around the 6900/4160 V transformers in the turbine building basement and moving the 6900/4160 V transformers – were evaluated as part of a previous design study for Catawba to address concerns raised in the IPE over a turbine building flood causing an extended loss of offsite power. Neither of these options were considered cost-effective at that time. At the staff's request (NRC 2001), Duke provided further information regarding the addition of a watertight wall as a potential SAMA (Duke 2002a; NRC 2002a). This plant modification is included as an additional SAMA in Table 5-5.

Duke also considered potential alternatives to reduce containment failure modes of concern for Catawba. These alternatives included nine containment-related improvements evaluated as part of the staff's assessment of SAMDAs for Watts Bar (NRC 1995a) and five containment-related improvements (e.g., procedures for reactor coolant system depressurization, procedures to cope with and reduce induced SGTR) derived from the staff's generic report on the individual plant examination program (NRC 1997c). Duke eliminated those alternatives that were either (1) already implemented at Catawba or (2) not applicable to the Catawba containment. Based on the screening, Duke designated nine of the containment-related SAMAs for further study. The list of the potential enhancements to improve containment performance is presented in Table 5-6.

In the Catawba ER, Duke identified the installation of back-up power to the igniters and the installation of back-up power to air-return fans as two separate SAMAs. However, in responses to staff RAIs, Duke indicated that the availability of air-return fans would be essential to the effective operation of igniters in an SBO; therefore, Duke treated the combined modification as a single SAMA. Accordingly, these two hydrogen control related SAMAs are shown as a single SAMA in Table 5-6. This effectively reduces the number of containment-related SAMAs to eight.

Table 5-5. SAMA Cost/Benefit Screening Analysis – SAMAs that Reduce CDF

Potential Alternative	Sequences/Failures Addressed	Risk Reduction		Total Benefit (per unit)	Cost of Enhancement (per unit)
		CDF[(a)]	Population Dose [(b)] (person-rem [(c)])		
Man standby shutdown system (SSS) 24 hours/day with trained operator	Turbine building flood with a failure of diesel generators to run and operators fail to initiate SSS seal injection following a loss of offsite power (LOOP) event	5.4 x10^{-6}	4.1	$241,000	>$2.5 M[(d)(e)]
Install automatic swap-over to high pressure recirculation	LOCA cut sets with failure of operators to establish high pressure recirculation	1.5 x10^{-5}	1.1	$448,000	>$1 M
Replace reactor vessel with stronger vessel	Failure of reactor pressure vessel with failure to prevent core damage following a reactor pressure vessel breach	1.0 x10^{-6}	< 0.1	$30,000	>$1 M
Install third diesel generator	LOOP events, which includes turbine building flood and LOOP initiators.	1.6 x10^{-5}	14.0	$754,000	>$2 M
Install automatic refill to upper storage tank	Loss of instrument air with a failure of nuclear service water system sources and operators fail to refill UST from condensate grade sources	4.0 x10^{-6}	0.3	$120,000	>$1 M
Install watertight wall around the 6900/4160 V transformers in turbine building basement	Turbine building flood causing an extended loss of offsite power	1.4 x10^{-5}	12.4	$663,000	$250,000

(a) Total CDF = 5.8x10^{-5} per year
(b) Total population dose = 31.4 person-rem per year
(c) One person-Sv = 100 person-rem
(d) Cost estimates for manning the standby shutdown system apply on a per site rather than per unit basis. In order to provide a consistent basis for comparison with the estimated benefits (which are per unit), the estimated site costs were divided by two.
(e) M = million

Table 5-6. SAMA Cost/Benefit Screening Analysis – SAMAs that Improve Containment Performance

Potential Alternative	Risk Reduction		Total Benefit (per unit)	Cost of Enhancement (per unit)
	CDF	Population Dose (person-rem)[a]		
Install independent containment spray system	N/A	28.4	$918,000[b]	>$1 M[c]
Install filtered containment vent system	N/A	28.4	$918,000[b]	>$1 M
Install back-up power to igniters and install back-up power to air-return fans	N/A	28.4	$918,000[b]	$540,000
Install containment inerting system	N/A	28.4	$918,000[b]	>$1 M
Install additional containment bypass instrumentation (ISLOCA)	N/A	2.6	$84,000	>$1 M
Add independent source of feedwater to reduce induced SGTR	N/A	< 0.1	< $3,200	>$1 M
Install reactor cavity flooding system	N/A	7.3	$239,000	>$1 M
Install core retention device	N/A	< 0.1	< $3,200	>$1 M

(a) One person-Sv = 100 person-rem
(b) Total benefit based on eliminating all early and late containment failures
(c) M = million

5.2.3.2 Staff Evaluation

It should be noted that Duke has made extensive use of PRA methods to gain insights regarding severe accidents at Catawba. Risk insights from various Catawba risk assessments have been identified and implemented to improve both the design and operation of the plant. For example, using the IPE process, Duke identified and implemented modifications to procedures to (1) provide back-up cooling water to the centrifugal charging pumps, (2) improve plant personnel's awareness of the standby shutdown system importance, (3) improve standby shutdown system availability by administratively controlling and limiting the times when the standby shutdown system may be taken out of service, and (4) decrease the time required for service water system and component cooling water system maintenance. Examples of plant improvements being planned for implementation by Duke based on IPEEE findings are:

(1) addition of spacers and stiffening of side rails on the diesel generator battery racks

(2) relocation of an instrument to avoid a potential seismic interaction with adjacent piping

(3) replacement of a valve to eliminate seismic spatial interaction with a nearby spent fuel cooling line

(4) addition of instructions in the pre-fire plan for the electrical bus switching area

(5) replacement of reciprocal air compressors with centrifugal compressors, and routing cables for the new compressors to give sufficient redundancy in case of fires

(6) reinstallation of missing door bolts in the auxiliary shutdown panel cabinets (NRC 1999).

The implementation of such improvements reduced the risk associated with the major contributors identified by the Catawba PRA and contributed to the reduced number of candidate SAMAs identified as part of Duke's application for license renewal.

Duke's effort to identify potential SAMAs focused on areas found to be risk-significant in the Catawba PRA. The list of SAMAs generally coincide with accident categories that are dominant CDF contributors or with issues that tend to have a large impact on a number of accident sequences at Catawba. Duke made a reasonable effort to use the Catawba PRA to search for potential SAMAs and to review insights from other plant-specific risk studies and previous SAMA analyses for potential applicability to Catawba. The staff reviewed the set of potential enhancements considered in Duke's SAMA identification process. These enhancements include improvements oriented toward reducing the CDF and risk from major contributors specific to Catawba and improvements identified in the previous SAMDA review for Watts Bar (NRC 1995a) that would be applicable to Catawba.

The staff notes that most of the SAMAs involve major modifications and significant costs and that less expensive design improvements and procedure changes could conceivably provide similar levels of risk reduction. The staff requested additional information (NRC 2001) from Duke on less expensive alternatives that would yield similar benefits. In response, Duke provided additional information on (1) the cost to provide alternative power to hydrogen igniters for SBO, (2) the cost to provide passive autocatalytic recombiners (PARs) as an alternative to igniters, (3) the cost to install a dedicated line from the Wylie hydroelectric station as an alternative source of ac power, and (4) the cost to install a watertight wall around the 6900/4160 V transformers. This information was responsive to the staff's requests and provided additional depth to the SAMAs considered. These additional alternatives are further evaluated, along with the other SAMAs, in the sections that follow.

The staff concludes that Duke has used a systematic process for identifying potential design improvements for Catawba and that the set of potential design improvements identified by Duke is reasonably comprehensive and, therefore, acceptable.

5.2.4 Risk Reduction Potential of Design Improvements

Section 4.3 of Attachment H to the Catawba ER describes the process used by Duke to determine the risk reduction potential for each enhancement.

For each seismic initiator cut set, Duke calculated the associated offsite risk based on the population dose and CDF for the PDSs attributable to the seismic initiator. Implementation of the plant enhancement was assumed to completely eliminate the seismic risk associated with the cut set. For each (non-seismic) sequence/enhancement, Duke evaluated the severe accident sequences. In general, where an alternative impacted more than one severe accident sequence, Duke determined the cumulative risk reduction achievable by each SAMA. This was performed by identifying which basic events in the cut sets would be affected by the implementation of the particular SAMA and assuming that implementation of the basic event(s) would be completely eliminated by the SAMA. For each containment-related improvement, Duke assumed that all of the population dose associated with the release categories impacted by the SAMA would be eliminated. For those alternatives that benefit more than one containment failure mode (i.e., independent containment spray system, filtered containment vent, back-up power to igniters, back-up power to air-return fans, containment inerting system, and reactor cavity flooding system), the total population dose for all affected failure modes was assumed to be completely eliminated by implementing the alternative. For example, installation of a standpipe in containment for reactor cavity flooding, which could reduce the likelihood of both early containment failure associated with reactor vessel breach and late containment failure due to basemat melt-through, was assumed to completely eliminate the associated early and late containment failures.

The staff questioned Duke (NRC 2001) regarding the estimated risk reduction associated with addition of a third diesel generator (DG). This SAMA was estimated to provide about a 60 percent reduction in the CDF for SBO sequences (from 2.5×10^{-5} per year to 9.0×10^{-6} per year). Duke indicated that the risk reduction was based on eliminating all failures to start, failures to run, and common cause failures of the existing two DGs. However, it was assumed that the third DG would not be seismically qualified; therefore, it would not be effective in seismic events. Since seismic events account for approximately one-third of the SBO CDF, the limited risk reduction estimated for the third DG appears reasonable. Duke also considered the additional benefit if the third diesel were seismically qualified similar to the existing DGs. Duke estimated that an additional reduction in CDF of about 4.0×10^{-7} per year would be achieved by eliminating all random failures of DGs in seismic events. This risk reduction is limited because the seismic results are dominated by seismic failures in the 4-kV power system for which improving diesel generator availability provides no benefit. The staff concludes that Duke's risk reduction estimates for this SAMA are reasonable.

An estimate of the risk reduction for the SAMA involving installation of a dedicated power line to the Wylie hydroelectric station was not provided in Duke's RAI response. However, the risk reduction would be comparable to that for adding a third DG, because the seismic fragility of the hydroelectric unit is expected to be similar to that for the seismically qualified DGs.

The staff notes that Duke evaluated the risk reduction potential for each SAMA in a bounding fashion. Each SAMA was assumed to completely eliminate all sequences that the specific enhancement was intended to address; therefore, the benefits are generally overestimated and conservative, including SAMAs related to SGTR events. Accordingly, the staff based its estimates of averted risk for the various SAMAs on Duke's risk reduction estimates.

5.2.5 Cost Impacts of Candidate Design Improvements

Duke's estimated costs for each potential design enhancement are provided in Tables 4-1, 4-2, and 5-1 of Attachment H to the ER. For most of the SAMAs, Duke estimated the cost of implementation to be greater than $1 million based on cost estimates developed in previous industry studies. For one SAMA, which involved installing a third DG, Duke developed plant-specific cost estimates because there was no readily available information on the estimated cost to implement similar alternatives and because the basic events associated with this alternative were found to have a high importance in the Catawba PRA. Because the safety benefits ($754,000) of the potential SAMA was significantly less than the estimated implementation costs ($2 million), the cost estimate was not further refined.

The staff compared Duke's cost estimates with estimates developed elsewhere for similar improvements, including estimates developed as part of the evaluation of SAMDA for operating reactors and advanced LWRs. The staff notes that Duke's estimated implementation costs of $1 million or greater are consistent with the values reported in previous analyses for major hardware changes of similar scope and are not unreasonable for the SAMAs under consideration, given that these enhancements involve major hardware changes and impact safety-related systems. For example, Duke estimated the cost to install a third DG to be approximately $2 million; this value is less than the cost estimates reported in previous SAMDA analyses for a similar design change.

Duke's estimate of the cost to install a dedicated line from the Wylie hydroelectric station as an alternate source of ac power also appears reasonable. This line would be buried to eliminate weather-related common cause failures. The estimated cost ($8 million) is greater than, but comparable to the cost estimates for a similar modification provided by Duke (Duke 2002b) for the McGuire Nuclear Station ($3 million) and by Dominion Power (NRC 2002c) for the Surry Nuclear Power Station ($2 to 5 million). Even the lowest of these estimates is far greater than the calculated benefit of $750,000 for Catawba.

The staff questioned Duke regarding the costs of less expensive alternatives that could offer similar risk reduction benefits, particularly with regard to installation of a watertight wall to address turbine flooding events and to improvements to control hydrogen in SBO events. Duke's estimate of the cost to install a watertight wall around the 6900/4160 V transformers in the turbine building basement is $250,000 per unit (NRC 2002a). The estimated cost breakdown is $75,000 for engineering, $25,000 for materials, and $150,000 for installation labor. These costs appear reasonable given the constraints in installing the modification in an existing plant.

In a February 1, 2002, response to staff RAIs (Duke 2002a), Duke provided additional information on the costs associated with installing a passive hydrogen control system based on the use of PARs in lieu of the present ac-dependent hydrogen igniters and the costs of powering a subset of the current hydrogen igniters from a back-up generator. For scoping purposes, Duke provided supplementary information regarding the cost of back-up power to the igniters and air-return fans in response to a follow-up RAI (NRC 2002a).

Duke's estimate of the cost to establish a capability to power a subset of igniters from a back-up generator was $205,000 for each unit. This modification, as defined by Duke, would involve pre-staging a single, dedicated generator for each unit outdoors on a concrete pad (for ventilation and exhaust considerations), and supplying the necessary power cables and circuit breakers to enable connection to the igniter branch circuits. The breakdown of this cost is $5,000 for engineering, $50,000 for materials, $110,000 for installation labor, and $40,000 for maintenance and operation. This cost estimate does not include an enclosure, tornado protection for the generator, or any seismic design. Duke further noted that providing electric power to hydrogen igniters during a SBO will not be effective without also powering at least one of the containment air-return fans and that this will further increase the cost of this option. When one air-return fan is added to this estimate, the combined cost is $540,000 per unit. The breakdown of this cost is $50,000 for engineering, $210,000 for materials, $240,000 for installation labor, and $40,000 for maintenance and operation. Duke points out there will be additional costs not included in these estimates.

The staff requested additional information on PARs because PARs are to be installed in French PWRs by 2007 to mitigate the consequences of hydrogen combustion events. In response (Duke 2002a), Duke estimated that the installation of PARs would cost more than $750,000 per unit, which is well above the estimated benefit (see Table 5-7, Section 5.2.6.2). This cost estimate is consistent with independent staff cost estimates for installing PARs.

The staff asked for further information on the basis for the greater than $1 million cost estimate for installing an automatic swap-over to high pressure recirculation. Duke (NRC 2002a) referenced NUREG-0498, Supp. 1 (NRC1995a), which estimated a cost of about $2.1 million for a similar alternative (i.e., "automate the alignment of emergency care cooling system [ECCS] recirculation to the high-pressure charging and safety injection pumps"). This would reduce the potential for related human errors made during manual realignment. This cost estimate is considerably higher than the estimated averted risk benefit for Catawba of about $448,000. (Benefits are discussed further in Section 5.2.6.)

The staff concludes that the cost estimates provided by Duke are reasonable and adequate for the purposes of this SAMA evaluation. As noted in Section 5.2.6.2, further attention will be placed on the costs associated with SBO-related plant improvements by the NRC as part of the resolution of Generic Safety Issue 189 (GSI-189) - Susceptibility of Ice-Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident (NRC 2002b). Also, as noted in Section 5.2.6.2, the need for additional evaluation and possible implementation of the watertight wall around the 6900/4160 V transformers has been identified as a current operating plant issue. Duke has made a commitment to design and install flood protection around these transformers (Duke 2002c).

5.2.6 Cost-Benefit Comparison

The cost-benefit comparison as evaluated by Duke and the staff evaluation of the cost-benefit analysis are described in the following sections.

5.2.6.1 Duke Evaluation

In the analysis provided by Duke in the ER, Duke did not include the following factors in its cost-benefit evaluation: replacement power costs for SAMAs that have the potential to reduce CDF and averted offsite property damage costs for SAMAs that have the potential to improve containment performance. In view of the significant impact of these averted costs on the estimated benefit for a SAMA, the staff requested that Duke include these factors in the cost-benefit analysis for each affected SAMA. In response to the RAI (Duke 2002a), Duke updated the benefit estimates to include averted replacement power costs and averted offsite property damage costs.

The methodology used by Duke 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 + AOEC +AOE + AOSC) - COE

where APE = present value of averted public exposure ($)
AOEC = present value of averted offsite property damage costs ($)
AOE = present value of averted onsite exposure costs ($)
AOSC = present value of averted onsite cleanup costs ($)
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. Duke's derivation of each of the associated costs is summarized below.

Averted Public Exposure (APE) Costs

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (person-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. Duke used the following expression when calculating the APE for the 20-year license renewal period:

APE = $\$2.20\times10^4$ x (Change in public exposure)

Averted Offsite Property Damage Costs (AOC)

For SAMAs that reduce CDF, 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

Duke derived the values for averted offsite property damage costs based on information provided in Section 5.7.5 of NUREG/BR-0184 (NRC 1997b). A discount factor of 7 percent and a 4-percent rate of inflation were used. Duke used the following expression when calculating the AOC for the 20-year license renewal period:

AOC = $\$3.92\times10^9$ x (Change in annual CDF)

Originally, as part of the ER, Duke did not include the AOC for containment-related SAMAs. In response to staff RAIs (Duke 2002a), Duke incorporated AOC as follows.

For containment-related SAMAs (which impact population dose but not CDF), Duke estimated the combined AOC and APE costs based on a conversion factor of $3000/person-rem, which Duke attributed to NUREG/CR-6349 (NRC 1995b). Duke used the following expression when calculating these costs (for containment-related SAMAs) for the 20-year license renewal period:

$$AOC + APE = \$3.23 \times 10^4 \text{ x (Change in public exposure)}$$

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

Duke derived the values for averted occupational exposure based on information provided in Section 5.7.3 of NUREG/BR-0184 (NRC 1997b). Best estimate values provided for immediate occupational dose 33 person-Sv (3300 person-rem) and long-term occupational dose [200 person-Sv (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 NUREG/BR-0184 in conjunction with a monetary equivalent of unit dose of $2000 per person-rem, a discount rate of 7 percent, and a time period of 20 years to represent the license-renewal period. Duke used the following expression when calculating the AOE for the 20-year license renewal period:

$$AOE = \$3.1 \times 10^8 \text{ x (Change in annual CDF)}$$

Averted Onsite Cleanup Costs (AOSC) (Not Including Replacement Power Costs)

The AOSCs, as calculated by Duke, include averted cleanup and decontamination costs. NUREG/BR-0184, Section 5.7.6.2 states that long-term replacement power costs must also be considered (NRC 1997b). Duke did not include this cost in the ER. However, Duke did add it in the responses (Duke 2002a) to the staff's RAIs.

Averted cleanup and decontamination costs (ACC) are 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 (NRC 1997b) as $\$1.5{\times}10^9$ (undiscounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. Duke used the following expression when calculating the ACC for the 20-year license renewal period:

$$ACC = \$1.18{\times}10^{10} \text{ x (Change in annual CDF)}$$

<u>Averted Power Replacement Cost (APRC)</u>

The Duke estimate of the annual power replacement cost for Catawba is based on an assumed discount rate of 7 percent for the 20-year license renewal period.

The estimated present power replacement costs of a severe accident occurring in each year of the license renewal period is given by (equation from NUREG/BR-0184, page 5.44):

$$PV_{RP} = [\$1.2{\times}10^8/0.07][1 - \exp(-0.07 \text{ x } 20)]^2$$

$$PV_{RP} = \$9.73{\times}10^8$$

Then, to estimate the net present value of power replacement over the 20-year license renewal (equation from NUREG/BR-0184, page 5.44):

$$U_{RP} = [PV_{RP}/0.07][1 - \exp(-0.07 \text{ x } 20)]^2$$

$$U_{RP} = \$7.89{\times}10^9$$

$$APRC = U_{RP} \text{ x (Change in annual CDF)}$$

Since the APRC from the NUREG is in 1990 dollars, an assumption is made to include a 4 percent inflation rate over 11 years to bring the value into 2001 dollars; therefore,

$$APRC = \$1.21{\times}10^{10} \text{ x (Change in annual CDF)}$$

<u>Duke Results</u>

The total benefit associated with each of the 14 SAMAs evaluated by Duke (six that reduce CDF and eight that improve containment performance) is provided in Tables 5-5 and 5-6. Two of the SAMAs have a positive net value (i.e., the total benefit is greater than the cost of the enhancement). These SAMAs involve installing a watertight wall around the 6900/4160 V transformers and installing back-up power to igniters and air-return fans. All of the remaining

SAMAs have a negative net value even given the bounding risk reduction benefits inherent in these estimates.

5.2.6.2 Staff Evaluation

The cost-benefit analysis provided by Duke (Duke 2001a; Duke 2002a) was based primarily on NRC's *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997b). In the original Catawba ER, Duke did not include averted replacement power costs for SAMAs that reduce CDF and averted offsite property damage costs for SAMAs that improve containment performance. However, the impact of these factors was included in supplemental analyses provided by Duke in response to the staff's RAIs (Duke 2002a; NRC 2002a). The APRC were assessed appropriately and the values calculated by Duke are consistent with independent staff assessments.

Duke used a conversion factor of $3,000/person-rem to determine the averted offsite property damage and APE costs. This effectively assumes a $1,000/person-rem conversion factor as a surrogate for averted offsite property damage, in addition to the accepted $2,000/person-rem conversion factor for averted offsite public exposure costs. Because offsite property damage costs are plant and site-specific, it would be more consistent with standard practice to actually calculate the property damage using the MACCS code. Nevertheless, the averted offsite costs values (for health effects and property damage) calculated by Duke provide reasonably good agreement with typical site values and are acceptable for purposes of estimating the value of containment-related SAMAs. Inclusion of averted replacement power and offsite property damage costs did not result in identification of any additional cost-beneficial SAMAs, and would not call into question Duke's decision to eliminate seismic SAMAs from consideration given the large costs associated with seismic SAMAs.

Based on the staff evaluation, two SAMAs (which involve installing a watertight wall around the 6900/4160 V transformers and installing back-up power to igniters and air-return fans) are potentially cost-beneficial and are discussed below. Several of the containment-related SAMAs (Table 5-6) have total benefits that are only slightly less than the estimated cost to implement the enhancement, specifically, installation of an independent containment spray system, a filtered containment vent system, and a containment inerting system. However, the estimated risk reduction in Table 5-6 is based on the bounding assumption that all early and late containment failures would be completely eliminated. Realistically, only a small fraction of the total risk would be eliminated by any one SAMA. Also, the cost to implement any of these three SAMAs would be substantially (i.e., a factor of 5) greater than $1 million, as each SAMA would involve a major hardware modification. Thus, these three SAMAs would not be cost-beneficial. All of the remaining SAMAs have costs that are at least a factor of two higher than the dollar equivalent of the associated benefits. This difference is considered to provide ample margin to cover uncertainties in the risk and cost estimates since estimates for these factors were generally evaluated in a conservative manner. This is true even when considering the 3-percent versus 7-percent discount rate sensitivity case or the use of a 40-year versus 20-year time period.

The positive net value of the watertight wall is due in part to the relatively large (approximately 24 percent) contribution of internal floods to total CDF. Duke assumed that the watertight wall would completely eliminate the turbine building flood initiators. The net value of this SAMA is approximately $400,000 (the difference between the estimated benefit and estimated cost in Table 5-5). This value is based on risk reduction estimates derived from PRA Revision 2b, and is consistent with the NRC's *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997b): the value assumes a 7-percent discount rate and includes averted onsite costs and averted power replacement costs.

Duke (NRC 2002a) provided a revised risk reduction estimate for the watertight wall based on an updated PRA model which accounts for recently installed reactor coolant pump seals that use O-ring materials that perform better at high temperature. This plant modification is expected to reduce the probability of a reactor coolant pump seal LOCA following a loss of seal cooling. Since a large fraction of the core damage sequences initiated by the turbine building flood involve seal LOCAs, the modification will reduce the CDF contribution from the flood and the risk reduction associated with the watertight wall. Using the revised PRA model, Duke estimates that the watertight wall will provide a CDF reduction of 1.0×10^{-5} per year and a population dose reduction of 0.151 person-Sv (15.1 person-rem) per year.

Based on the revised risk reduction values, the watertight wall would have an estimated benefit of $550,000 (positive net value of $300,000). Use of a 3-percent discount rate would increase the net value to about $500,000. If averted onsite costs and averted power replacement costs are neglected in the analysis, the estimated benefit would be approximately $214,000 (negative net value of $36,000). However, using either a 3-percent discount rate or 40-year time period, the net value would remain positive even when averted onsite costs and averted power replacement costs are neglected. Based on this information, the staff concludes that the installation of the watertight wall would be cost-beneficial. The need for additional evaluation and possible implementation of the watertight wall around the 6900/4160 V transformers will be addressed as a current operating plant issue. Duke has made a commitment to design and install flood protection around these transformers (Duke 2002c).

The positive net value of installing back-up power to igniters is due in part to the relatively high frequency of SBO events for Catawba (which account for 43 percent of the total CDF of 5.8×10^{-5} per year based on Revision 2b of the PRA), combined with the vulnerability of ice-condenser containments to hydrogen combustion in SBO events, as described in NUREG/CR-6427 (NRC 2000). This NUREG provided a simplified Level 2 analysis for the purpose of investigating the importance of direct containment heating (DCH). The NUREG found that early containment failure is dominated by hydrogen combustion events rather than DCH events and that no ice-condenser plant is inherently robust to all credible DCH or hydrogen combustion events in station blackout. The study concluded that all ice-condenser plants would benefit from reducing SBO frequency or from providing some means of hydrogen control that is effective in SBO events. It should be noted that the NUREG contains several assumptions that may be justified for purposes of dispositioning the DCH issue but are not necessarily consistent with the best-estimate philosophy of PRA (such as a bounding assumption that random ignition prior to vessel breach will not occur). Accordingly, the NUREG is useful for understanding the uncertainties associated with early containment failure probabilities, but should not be interpreted as providing a realistic or best-estimate evaluation of the potential for early containment failure as a result of hydrogen combustion during SBO events.

In light of the issues raised in NUREG/CR-6427 concerning the likelihood of early containment failure in SBO events, the staff requested Duke to provide a reevaluation of the benefits associated with the hydrogen control measures (install back-up power to igniters and air-return fans) assuming a containment response consistent with the findings in NUREG/CR-6427 (i.e., using the containment failure probabilities for DCH and non-DCH events reported in the study, in place of the conditional failure probabilities implicit in the baseline PRA). Under these assumptions, Duke estimated that the averted population dose from eliminating early containment failures would rise from a base case value of 0.073 person-Sv (7.3 person-rem) per year to 0.12 person-Sv (12.0 person-rem) per year. The benefit values based on use of the NUREG/CR-6427 containment failure probability for Catawba are reported in Table 5-7. Also shown are the benefit values for the sensitivity case involving use of a 3-percent discount rate instead of a 7-percent discount rate. All of the values in Table 5-7 include averted offsite property damage.

A number of points are worth noting regarding the Duke base case results and these sensitivity assessments:

- Not all early and late releases can be eliminated by providing hydrogen control. For example, late failures due to long-term containment over-pressure could still occur. Also, the non-safety related, non-seismic back-up power source may not be available in large seismic and tornado events if it is not designed to withstand such events. An upper bound estimate can be provided by assuming that all containment failures, early and late, would be eliminated. More realistically, most of the early and some of the late releases would be eliminated. The assumption that hydrogen control would eliminate all early failures is considered to provide a reasonable estimate of the risk reduction benefit. Accordingly, the estimated benefits shown in Table 5-7 are based on eliminating all early containment failures.

Table 5-7. Sensitivity Results for Hydrogen Control SAMAs
(all benefits based on eliminating early failures only)

SAMA	Estimated Cost (per unit)	Estimated Benefits for Hydrogen Control SAMAs Under Various Assumptions (per unit)		
		Based on Revision 2b of the PRA	Based on conditional containment failure probabilities from NUREG/CR-6427	Based on a 3% discount rate compared to a 7% discount rate in the base case
Back-up power to igniters and air-return fans	$540,000	$236,000	$387,000	$329,000
PARs	$750,000	$236,000	$387,000	$329,000
Back-up power to igniters only	$205,000	Duke: no benefit, since air-return fans are needed	Duke: no benefit, since air-return fans are needed	Duke: no benefit, since air-return fans are needed

- It is Duke's position that powering the igniters without also powering the air-return fans would not achieve effective hydrogen control. According to Duke, in order to realize the stated benefits, the air-return fans must also have a back-up power source. More than half of the cost of the SAMA to provide back-up power to igniters and air-return fans comes from powering the fans. Based on available technical information, it is not clear that operation of the air-return fans is necessary to provide effective hydrogen control. The need to also supply back-up power to the air-return fans is being further assessed by the NRC as part of the resolution of GSI-189. If only the igniters need to be powered during SBO, a less-expensive option of powering a subset of igniters from a back-up generator, addressed by Duke in responses to RAIs (Duke 2002a; NRC 2002a), is within the range of averted risk benefits and would warrant further consideration.

- If a 3-percent discount rate is assumed in contrast to the 7-percent discount rate assumed in the base case analysis, the SAMA is cost-beneficial if back-up power to the air-return fans is not needed. This further supports the position that the benefits are large and that a hydrogen-related SAMA may be cost-beneficial.

- The effect of implementing the SAMA in the near term rather than delaying implementation until the start of the license renewal period (i.e., use of a 40-year rather than a 20-year period in the value analyses) is bounded by the sensitivity study that assumed a 3-percent discount rate.

The NRC has recognized that ice-condenser containments like Catawba's are vulnerable to hydrogen burns in the absence of power to the in-place hydrogen ignitor system. This is sufficiently important for all PWRs with ice-condenser containments that NRC has made the issue a Generic Safety Issue, GSI-189 - Susceptibility of Ice-Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident (NRC 2002b). As part of the resolution of GSI-189, NRC is evaluating potential improvements to hydrogen control provisions in ice-condenser plants to reduce their vulnerability to hydrogen-related containment failures in SBO. This will include an assessment of the costs and benefits of supplying igniters from alternate power sources, such as a back-up generator, as well as containment analyses to establish whether air-return fans also need an ac-independent power source, as part of this modification. The need for plant design and procedural changes will be resolved as part of GSI-189 and addressed for Catawba and other ice-condenser plants as a current operating license issue.

5.2.7 Conclusions

Duke completed a comprehensive effort to identify and evaluate potential cost-beneficial plant enhancements to reduce the risk associated with severe accidents at Catawba. As a result of this assessment, Duke concluded in the ER that no additional mitigation alternatives are cost-beneficial and warrant implementation at Catawba. Based on its review of SAMAs for Catawba, the staff concludes that two of the SAMAs are cost-beneficial under certain assumptions. These SAMAs involve installing a watertight wall around the 6900/4160 V transformers and providing back-up power to the hydrogen igniters for SBO events.

Based on the analyses presented, the staff concludes that installing a watertight wall around the transformer is cost-beneficial. However, as this SAMA does not relate to adequately managing the effects of aging during the period of extended operation, it need not be implemented as part of license renewal pursuant to 10 CFR Part 54. The staff intends to pursue this matter as a current operating license issue. By letter dated August 8, 2002, Duke committed to designing and scheduling the installation of flood protection for the 6900/4160 V transformers (Duke 2002c).

Duke's position, regarding the SAMA that would establish hydrogen control in SBO events by providing back-up power to igniters, is that this SAMA is not cost-effective because back-up power would need to be supplied to the air-return fans from ac-independent power sources in order to ensure mixing of the containment atmosphere, and the cost of powering both the igniters and the air-return fans would exceed the expected benefit. However, based on available technical information, it is not clear that operation of air-return fans is necessary to provide effective hydrogen control. If only the igniters need to be powered during SBO, a less-expensive option of powering a subset of igniters from a back-up generator, addressed by Duke in responses to RAIs (Duke 2002a; NRC 2002a), is within the range of the averted risk benefits and would warrant further consideration. Even if air-return fans are judged to be necessary to ensure effective hydrogen control in SBOs, the results of sensitivity studies suggest that this combined SAMA might also be cost-beneficial.

The staff concludes that the SAMA that would establish hydrogen control in SBO events by providing back-up power to igniters is cost-beneficial under certain assumptions, which are being examined in connection with resolution of GSI-189. However, this SAMA does not relate to adequately managing the effects of aging during the period of extended operation. Therefore, it need not be implemented as part of license renewal pursuant to 10 CFR Part 54. The need for plant design and procedural changes will be resolved as part of GSI-189 and addressed for Catawba and all other ice-condenser plants as a current operating license issue.

5.3 References

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

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

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