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Station Blackout Risk Evaluation for Nuclear Power Plants (Draft)

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ABSTRACT

This report is an update of several previous reports analyzing the risk from loss of offsite power and subsequent station blackout events at U.S. commercial nuclear power plants. The risk measure used is core damage frequency. Standardized plant analysis risk (SPAR) models developed by the U.S. Nuclear Regulatory Commission, covering the 103 operating commercial nuclear power plants, were used to evaluate the risk. Core damage frequency results indicating contributions from station blackout scenarios and other loss of offsite power scenarios are presented for each of the 103 plants, along with plant class and industry averages. In addition, a comprehensive review of emergency diesel generator performance was performed to obtain current estimates for input to the SPAR models. Overall results indicate that core damage frequencies for loss of offsite power and station blackout are lower than previous estimates. Contributing to this risk reduction is an improvement in emergency diesel generator performance.

Contents

Appendices

FIGURES

TABLES

EXECUTIVE SUMMARY

The availability of alternating current (AC) power to commercial nuclear power plants is essential for safe operations and accident recovery. Unavailability of AC power can have a major negative impact on a power plant's ability to achieve and maintain safe shutdown conditions. This AC power normally is supplied by offsite power sources (from the electrical grid to which the plant is connected), but can be supplied by onsite emergency AC power sources if offsite power is lost. Therefore, loss of offsite power (LOOP), reliability of onsite emergency AC power sources, and subsequent restoration of offsite power are important inputs to plant probabilistic risk assessments.

A subset of LOOP scenarios involves the total loss of AC power at a commercial nuclear power plant as a result of complete failure of both offsite and onsite AC power sources. These are termed station blackout (SBO) scenarios. In SBO situations, safe shutdown must be accomplished by relying on components that do not require AC power, such as turbine-driven pumps or diesel-driven pumps. The reliability of such components, along with direct current battery depletion times and the characteristics of offsite power restoration, are important contributors to SBO risk. Historically, risk models have indicated that SBO is an important contributor to overall plant risk, contributing as much as 70 percent or more.

Based on concerns about SBO risk and associated emergency diesel generator unreliability, the U.S. Nuclear Regulatory Commission (NRC) established Task Action Plan (TAP) A-44 in 1980. The NRC report NUREG-1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*, was issued in 1988 and integrated many of the efforts performed as part of TAP A-44. In 1988 NRC issued the SBO rule, 10 CFR 50.63, and the accompanying regulatory guide, RG 1.155. That rule required plants to be able to withstand an SBO for a specified duration and maintain core cooling during that duration. As a result of the SBO rule, plants were required to enhance procedures and training for restoring offsite and onsite AC power sources. In addition, in order to meet the rule's requirements, some plants chose to make modifications such as adding additional emergency AC power sources. Emphasis was also placed on establishing and maintaining high reliability of the emergency power sources.

Finally, a widespread grid-related LOOP occurred on August 14, 2003. That event resulted in LOOPs at nine U.S. commercial nuclear power plants. As a result of that event, the NRC initiated a comprehensive program that included updating and re-evaluating LOOP frequencies and durations and SBO risk. This report is part of that overall program and focuses on SBO risk.

The purpose of this study was to evaluate the current core damage risk from SBO scenarios at U.S. commercial nuclear power plants. All 103 operating commercial nuclear power plants were included in the analysis. Risk was evaluated only for internal events during critical operation; risk from shutdown operation and external events was not addressed. The standardized plant analysis risk (SPAR) models developed by the NRC for the 103 operating plants were used to evaluate core damage risk. An extensive set of enhancements was added to the existing SPAR models to provide up-to-date modeling of LOOP and SBO risk. In addition, emergency diesel generator (EDG) performance was re-evaluated based on recent data to establish current reliability levels.

SBO risk in terms of core damage can be thought of as the product of the LOOP frequency, the failure probability of the onsite emergency power system (EPS), and the composite failure probability of SBO coping features at a given plant. Each of these three contributors to SBO risk is discussed below.

The LOOP frequency and offsite power recovery efforts are documented in a separate report, *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (draft)*. That effort generated up-to-date frequencies for five categories of LOOPs, along with associated nonrestoration (of offsite power) curves versus time. Results indicated that LOOP frequencies have historically trended downward (Figure ES-1) but the durations of such events increased during the late 1980s and early 1990s and have since been reasonably constant (Figure ES-2). Sensitivity studies performed as part of this study indicate that the decreased LOOP frequencies and increased LOOP durations tend to cancel each other in terms of effects on SBO core damage frequency risk.

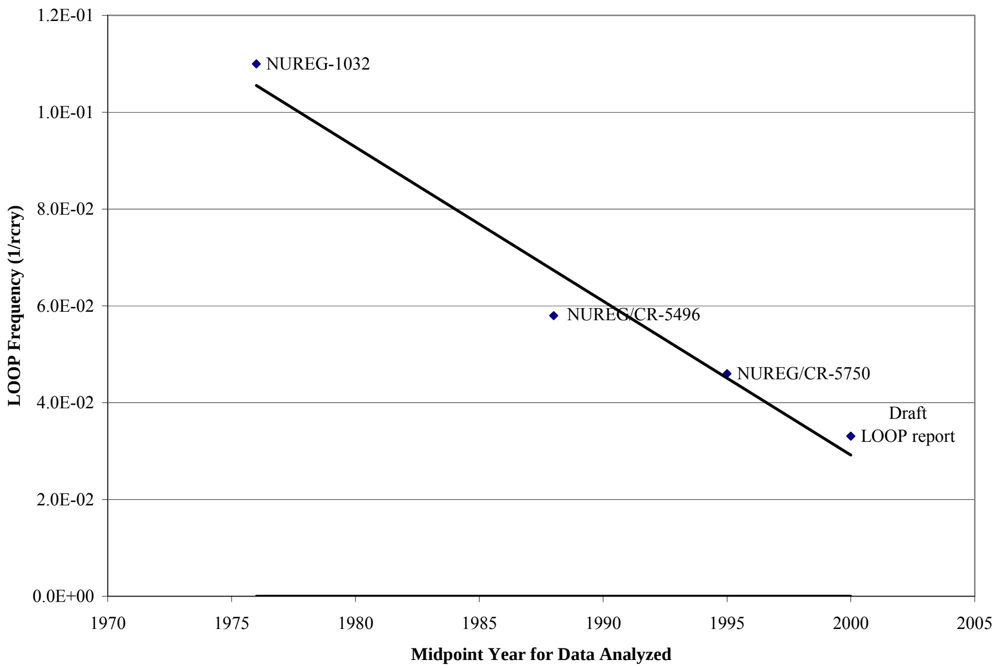


Figure ES-1. Overall industry LOOP frequency historical trend.

To develop estimates of current EDG performance, new EDG failure probabilities and rates were developed for fail to start, fail to load and run for one hour, fail to run beyond one hour, and unavailability due to test and maintenance. Values were derived from Equipment Performance and Information Exchange (EPIX) data for the period 1998 – 2002, except for the test and maintenance outages. Results were compared with EDG unplanned demand (undervoltage events requiring the EDGs to start, load and run) information from licensee event reports (LERs) over the period 1997 – 2003. Although the unplanned demand data were shown statistically to not be significantly different from the EPIX data, several issues were identified that merit continued collection and review of such data. EDG test and maintenance outage data were obtained from the Reactor Oversight Process Safety System Unavailability performance indicator for the period 1998 – 2002 (planned and unplanned outages only). Unplanned demand data were also compared with the test and maintenance outage probability and found to not be significantly different. The historical trend in EDG total unreliability (including the test and maintenance outages and assuming an eight-hour mission time) is presented in Figure ES-3. Sensitivity studies indicate that the improved EDG reliability shown in the figure is a significant factor in reducing SBO core damage risk.

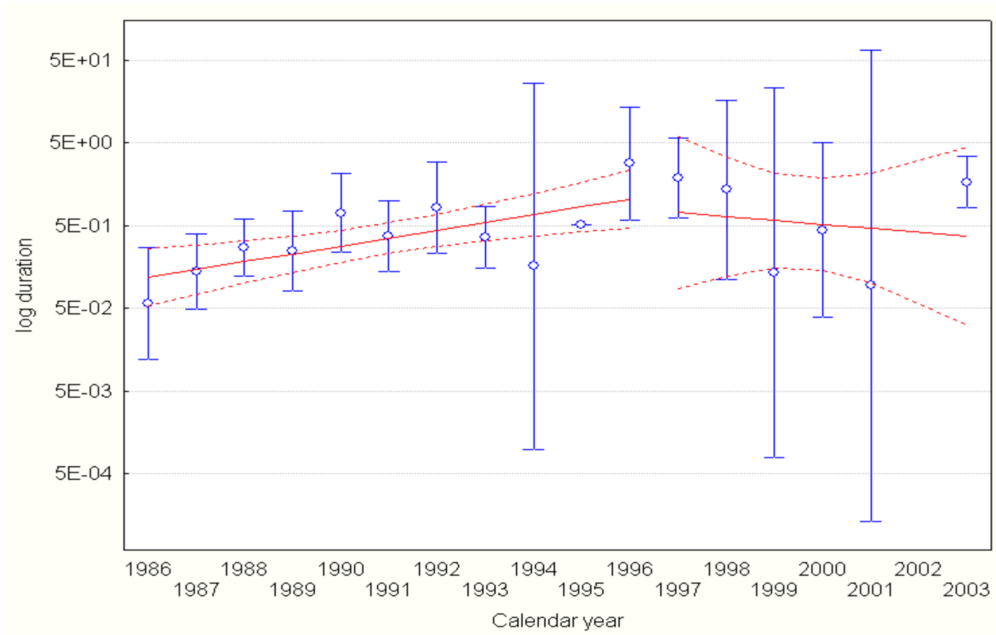


Figure ES-2. LOOP duration historical trends.

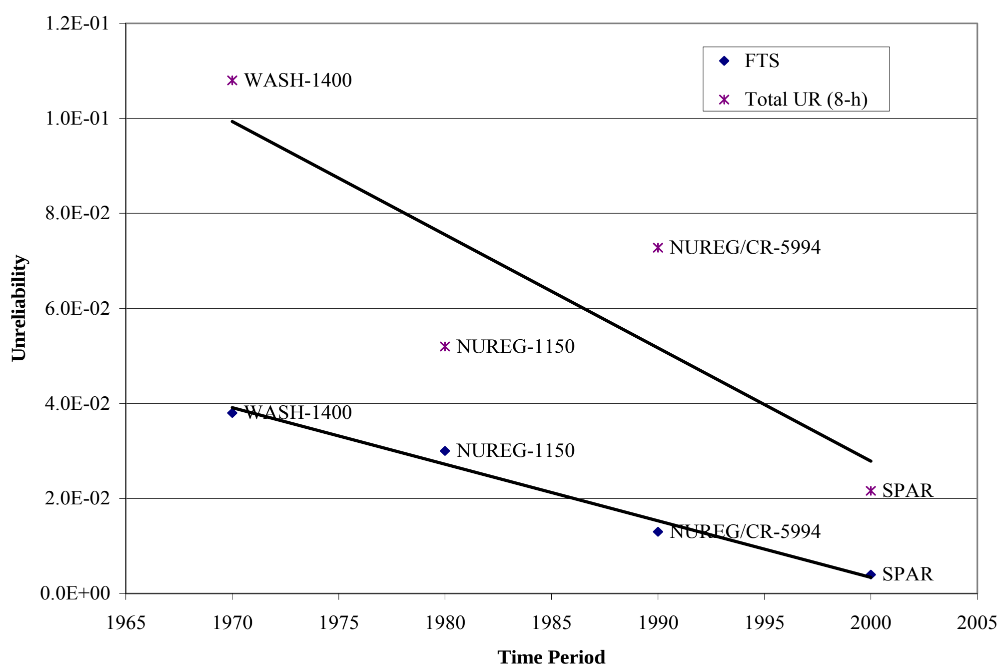


Figure ES-3. EDG fail to start and total unreliability historical trend.

SBO coping features were defined in this study to include all components, phenomena, and recoveries modeled in the SPAR SBO event trees. For components modeled in these event trees, such as turbine-driven pumps, high-pressure core spray motor-driven pumps (supported by their own EDGs), and diesel-driven pumps, updated performance data were collected and evaluated, similar to what was done for the EDGs. In all cases, the historical unreliabilities of these components have trended downward. The trend for turbine-driven pumps is presented in Figure ES-4. Improved reliability of these AC-independent components helps to reduce the SBO core damage risk, but not to the extent seen for the EDGs.

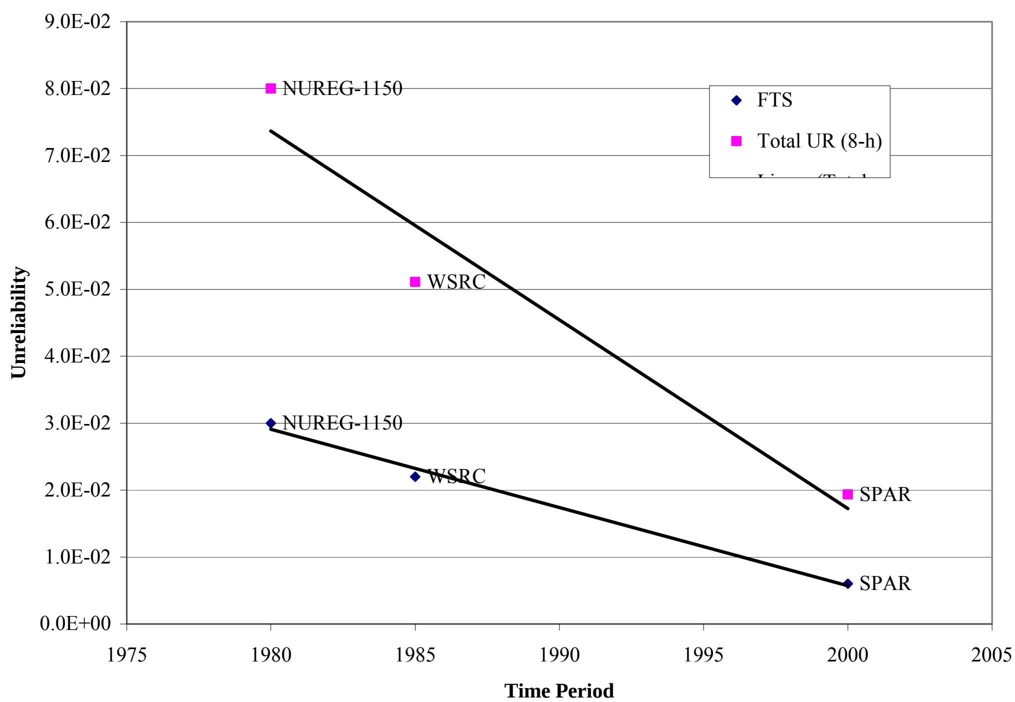


Figure ES-4. Turbine-driven pump fail to start and total unreliability historical trend.

Finally, the resulting SPAR models were quantified to obtain LOOP (non SBO) core damage frequency and SBO core damage frequency. In addition, the EPS failure probabilities were quantified, such that the SBO coping failure probabilities could be determined. Results indicate an industry average SBO core damage frequency (point estimate) of 2.9E-6 per reactor critical year (/rcry). Results were compared with historical estimates of SBO core damage frequency, ranging from approximately 1980 to the present. Again, these historical estimates trend downward, as indicated in Figure ES-5. The historical drop in SBO core damage frequency is probably the result of many changes – plant modifications made in response to the SBO rule, improvements in plant risk modeling, and improved component performance. However, the major contributor for this historical drop appears to be improved EDG performance.

Various sensitivity studies were also performed. As expected, the SBO core damage frequency is sensitive to EDG performance. In addition, the draft LOOP report identified a significantly higher LOOP frequency during the summer (May through September). Because of this difference, the potential effects from allowing 14-day outages for EDGs (assumed to occur approximately once every 36 months) is highly dependent upon when such outages occur. If such outages were to occur only during the summer months, the increase in SBO core damage frequency could be significant. However, if such outages were limited to the non-summer months, then the increase in SBO core damage frequency is negligible.

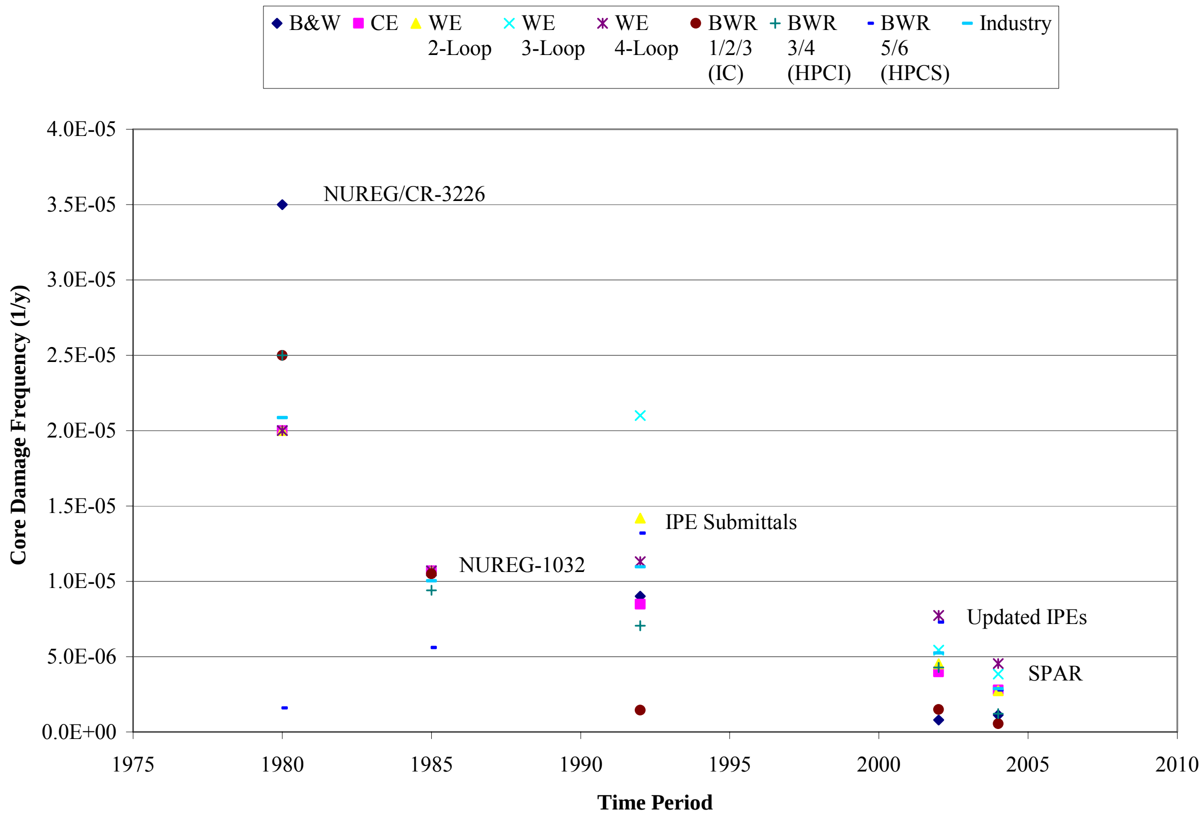


Figure ES-5. SBO core damage frequency historical trend.

Results of the study indicate several areas where continued monitoring of industry performance is recommended. First, the draft LOOP report indicated that the current LOOP frequency is dominated by the estimate for grid-related LOOPs. The grid-related LOOP frequency is heavily influenced by the August 14, 2003 widespread grid blackout that affected nine plants. Whether such events occur in the future (and if so, at what frequency) might affect the current LOOP frequency. In addition, the comparison of EDG unplanned demand data with EPIX data (used to develop the SPAR EDG failure probabilities and rates) indicated that fail to load and run failures (mostly recoverable) from the unplanned demands were different from fail to load and run failures from EPIX. In addition, the unplanned demand data for fail to run were almost significantly different. Collection of EDG unplanned demand data should continue, in order to monitor these issues. Finally, the EDG test and maintenance outage probability used in SPAR is based on Reactor Oversight Process Safety System Unavailability data. However, those data do not include overhaul maintenance outages. A limited comparison of these data with data from the Mitigating Systems Performance Index (MSPI) pilot plants (which did include such outages) indicated only an 18% to 24% increase in the probability from such outages. When MSPI unavailability data begin to be reported, the EDG (and other component) test and maintenance outage estimates should be reviewed.

Overall, the study was successful in evaluating SBO core damage risk for U.S. commercial nuclear power plants. A strength of the study was the use of updated SPAR models to cover all 103 plants. In addition, EDG performance was investigated in detail.

FOREWORD

The availability of alternating current (AC) electrical power is essential for safe operation and accident recovery of commercial nuclear power plants (NPPs). This essential power is normally supplied by offsite power sources from the electrical grid to which the plant is connected. If offsite power is lost, onsite AC electrical power is provided by highly reliable emergency diesel generators. The total loss of AC power at an NPP as a result of complete failure of both offsite and onsite AC power sources, which rarely occurs, is referred to as “station blackout” (SBO).

Unavailability of AC power can have a significant adverse impact on a plant’s ability to achieve and maintain safe-shutdown conditions. In fact, risk analyses performed for NPPs indicate that the loss of all AC power can be a significant contributor to the risk associated with plant operation, contributing more than 70 percent of the overall risk at some plants. Therefore, a loss of offsite power (LOOP) and its subsequent restoration are important inputs to plant risk models, and these inputs must reflect current industry performance in order for plant risk models to accurately estimate the risk associated with LOOP-initiated scenarios.

One subset of LOOP-initiated scenarios of extreme importance involves SBO. In SBO situations, the affected plant must achieve safe shutdown by relying on components that do not require AC power, such as turbine-driven or diesel-driven pumps. Thus, the reliability of such components, direct current (DC) battery depletion times, and the characteristics of offsite power restoration, are important contributors to SBO risk.

Based on concerns about SBO risk and associated unreliability of emergency diesel generators, the U.S. Nuclear Regulatory Commission (NRC) established Task Action Plan (TAP) A-44 in 1980. The NRC also issued NUREG-1032, “Evaluation of Station Blackout Accidents at Nuclear Power Plants,” dated 1988, which incorporated many of the actions performed as part of TAP A-44. In addition, in 1988, the NRC issued the SBO rule and the associated Regulatory Guide (RG) 1.155, entitled “Station Blackout.” As set forth in Title 10, Section 50.63, of the *Code of Federal Regulations* (10 CFR 50.63), the SBO rule requires that NPPs must have the capability to withstand an SBO and maintain core cooling for a specified duration. As a result, NPPs were required to enhance procedures and training for restoring offsite and onsite AC power sources. Also, in order to meet the requirements of the SBO rule, some licensees chose to make NPP modifications, such as adding additional emergency AC power sources. The NRC and its licensees also placed additional emphasis on establishing and maintaining high reliability of the onsite emergency power sources.

Then, on August 14, 2003, a widespread grid-related blackout event resulted in LOOPs at nine U.S. commercial NPPs. As a result, the NRC initiated a comprehensive program that included updating and reevaluating LOOP frequencies and durations, as well as the associated SBO risk. This report, which focuses on SBO risk, is part of that comprehensive program.

This report presents the current core damage risk associated with SBO scenarios at all 103 operating U.S. commercial NPPs. In conducting the reported evaluation, the researchers evaluated risk only for internal events during critical operation; thus, the evaluation did not address the risks associated with either shutdown operation or external events. To evaluate core damage risk, the researchers used the standardized plant analysis risk (SPAR) models, which the NRC developed for the Nation's 103 operating plants. The researchers also augmented the existing SPAR models by adding an extensive set of enhancements to provide up-to-date modeling of LOOP and SBO risk. In addition, the researchers reevaluated emergency diesel generator performance using recent data to establish current reliability levels.

The evaluation results indicate an industry average SBO core damage frequency (point estimate) of 2.9×10^{-6} per reactor critical year (rcry). This report compares those results with historical estimates from approximately 1980 through the present, which show a downward trend from a high of 2.0×10^{-5}/rcry to the present value. This historical decrease in SBO core damage frequency is probably the result of many factors, including plant modifications in response to the SBO rule, improvements in plant risk modeling, and improved component performance. However, the major contributing factor for this historical decrease appears to be improved emergency diesel generator performance.

This report also documents several sensitivity studies. As expected, SBO core damage frequency is sensitive to emergency diesel generator performance. In addition, the companion draft report, entitled "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003," which the NRC issued for public comment on December 17, 2004, identified a significantly higher LOOP frequency during the summer months (May – September). (See the related notice in the *Federal Register*, Vol. 69, No. 242, page 75570.) As a result, the potential effects of allowing 14-day outages for emergency diesel generators (which are assumed to occur approximately once every 36 months) are highly dependent upon when such outages occur. If such outages occur only during the summer months, the increase in SBO core damage frequency would be significant. However, if such outages are limited to the non-summer months, the increase in SBO core damage frequency would be negligible.

Overall, the study succeeded in evaluating the risk of SBO core damage frequency for U.S. commercial NPPs. Strengths of the study are the use of the SPAR models to cover all 103 plants and the review of recent emergency diesel generator performance.

ACKNOWLEDGMENTS

The authors would like to acknowledge the support of J. Schroeder and R. Buell in updating the standardized plant analysis risk (SPAR) models used to estimate the core damage frequency risk from loss of offsite power initiators and subsequent station blackout events. In addition, significant software support for the SAPHIRE code was provided by T. Wood and K. Kvarfordt. Finally, C. Gentillon performed the statistical comparison of the SPAR emergency diesel generator data with unplanned demand data from 1997 – 2003.

ACRONYMS

AC	alternating current
AFW	auxiliary feedwater system
ATWS	anticipated transient without scram
BW or B&W	Babcock & Wilcox
BWR	boiling water reactor
CCF	common-cause failure
CD	core damage
CDF	core damage frequency
CE	Combustion Engineering
CNID	constrained noninformative distribution
CY	calendar year
DDP	diesel-driven pump
EDG	emergency diesel generator
EPIX	Equipment Performance and Information Exchange
EPS	emergency power system
FTLR	fail to load and run (for one hour)
FTR	fail to run (beyond one hour)
FTS	fail to start
GE	General Electric
GTG	gas turbine generator
HPCI	high-pressure coolant injection
HPCS	high-pressure core spray
HTG	hydro turbine generator
IC	isolation condenser system
IPE	Individual Plant Examination
LER	licensee event report
LERF	large early release fraction
LOOP	loss of offsite power
MDP	motor-driven pump
MOOS	maintenance out of service
MSPI	Mitigating Systems Performance Index
PORV	power-operated relief valve
PRA	probabilistic risk assessment
PWR	pressurized water reactor
RADS	Reliability and Availability Database System

Acronyms

RCIC	reactor core isolation cooling
RCP	reactor coolant pump
ROP	Reactor Oversight Process
rcry	reactor critical year
rcy	reactor calendar year
SBO	station blackout
SER	safety evaluation report
SPAR	standardized plant analysis risk
SSU	safety system unavailability
TAP	task action plan
TDP	turbine-driven pump
TM	test and maintenance outage
UA	Unavailability
UR	Unreliability
WE	Westinghouse

GLOSSARY

Actual bus restoration time – the duration, in minutes, from the event initiation until the first offsite electrical power was restored to a safety bus. This is the actual time taken to restore offsite power from the first available source to a safety bus.

Extreme-weather-related loss of offsite power event – a LOOP event caused by extreme weather. Examples of extreme weather are hurricanes, strong winds greater than 125 miles per hour, and tornadoes. Extreme-weather-related LOOP events are also distinguished from severe-weather-related LOOP events by their potential to cause significant damage to the electrical transmission system and long offsite power restoration times.

Grid-related loss of offsite power event – a LOOP event in which the initial failure occurs in the interconnected transmission grid that is outside the direct control of plant personnel. Failures that involve transmission lines from the site switchyard are usually classified as switchyard-centered events if plant personnel can take actions to restore power when the fault is cleared. However, the event should be classified as grid related if the transmission lines fail from voltage or frequency instabilities, overload, or other causes that require restoration efforts or corrective action by the transmission operator.

Loss of offsite power (LOOP) event – the simultaneous loss of electrical power to all unit safety buses (also referred to as emergency buses, Class 1E buses, and vital buses) requiring all emergency power generators to start and supply power to the safety buses. The non-essential buses may also be de-energized as a result of this.

Plant-centered loss of offsite power event – a LOOP event in which the design and operational characteristics of the nuclear power plant unit itself play the major role in the cause and duration of the loss of offsite power. Plant-centered failures typically involve hardware failures, design deficiencies, human errors, and localized weather-induced faults such as lightning. The line of demarcation between plant-centered and switchyard-centered events is the nuclear power plant main and station power transformers high-voltage terminals.

Potential bus restoration time – the duration, in minutes, from the event initiation until the first offsite electrical power could have been restored to a safety bus. This time estimate is less than or equal to the actual bus restoration time.

Severe-weather-related loss of offsite power event – a LOOP event caused by severe weather, in which the weather was widespread, not just centered on the site, and capable of major disruption. Severe weather is defined to be weather with forceful and non-localized effects. A LOOP is classified as a severe-weather event if it was judged that the weather was widespread, not just centered at the power plant site, and capable of major disruption. An example is storm damage to transmission lines instead of just debris blown into a transformer. This does not mean that the event had to actually result in widespread damage, as long as the potential is there. Examples of severe weather include thunderstorms, snow, and ice storms. Lightning strikes, though forceful, are normally localized to one unit, and so are coded as plant centered or switchyard centered. LOOP events involving hurricanes, strong winds greater than 125 miles per hour, and tornadoes are included in a separate category – extreme-weather-related LOOPs.

Station blackout (SBO) – the complete loss of alternating current (AC) electrical power to safety and non-essential buses in a nuclear power plant unit. Station blackout involves the loss of offsite power concurrent with the failure of the onsite emergency AC power system. It does not include the loss of available AC power to safety buses fed by station batteries through inverters or successful HPCS operation.

Switchyard-centered loss of offsite power event – a LOOP event in which the equipment or human-induced failures of equipment in the switchyard play the major role in the loss of offsite power. The line of demarcation between switchyard-related events and grid-related events is the output bus bar in the switchyard.

Switchyard restoration time – the duration, in minutes, from the event initiation until the first offsite electrical power was actually restored (or could have been restored, whichever time is shorter) to the switchyard. Such items as no further interruptions to the switchyard, adequacy of the frequency and voltage levels to the switchyard, and no transients that could be disruptive to plant electrical equipment should be considered in determining the time.

Total unreliability – the probability of a component failing to accomplish its mission because or either unreliability or unavailability.

Unavailability (UA) – the probability of a component failing to accomplish its mission because it is unavailable when demanded due to being in a test configuration or undergoing maintenance or repair. UA events are identified as TM events in the SPAR models. UA (or TM) is also identified as maintenance out of service (MOOS) in the NRC system studies.

Unreliability (UR) – the probability of a component failing to accomplish its mission because of either failure to start or failure to run (over a specified mission time). For components that must start and run, UR includes fail to start (FTS), failure to run for the first hour (FTR <1h), and failure to run for the remainder of the mission time (FTR >1h). The EDGs are a special case in that the FTR <1h failure mode is replaced by a similar event, failure to load and run for one hour (FTLR).

Station Blackout Risk Evaluation for Nuclear Power Plants

1. INTRODUCTION

The availability of alternating current (AC) power to commercial nuclear power plants is essential for safe operations and accident recovery. Unavailability of AC power can have a major negative impact on a power plant's ability to achieve and maintain safe shutdown conditions. This AC power normally is supplied by offsite power sources (from the electrical grid to which the plant is connected), but can be supplied by onsite emergency AC power sources if offsite power is lost. Therefore, loss of offsite power (LOOP), reliability of onsite emergency AC power sources, and subsequent restoration of offsite power are important inputs to plant probabilistic risk assessments (PRAs).

A subset of LOOP scenarios involves the total loss of AC power at a commercial nuclear power plant as a result of complete failure of both offsite and onsite AC power sources. These are termed station blackout (SBO) scenarios. (The detailed definitions of LOOP and SBO are presented in the Glossary.) In SBO situations, safe shutdown must be accomplished by components that do not rely on AC power, such as turbine-driven pumps (TDPs) or diesel-driven pumps (DDPs). The reliability of such components, along with direct current (DC) battery depletion times and the characteristics of offsite power restoration, are important contributors to SBO risk. Historically, risk models have indicated that SBO is an important contributor to overall plant risk, contributing up to 70% or more to the overall core damage frequency (CDF).

Based on concerns about SBO risk and associated emergency diesel generator (EDG) unreliability, the U.S. Nuclear Regulatory Commission (NRC) established Task Action Plan (TAP) A-44 in 1980[1]. To support TAP A-44, the report *Station Blackout Accident Analyses (Part of NRC Task Action Plan A-44)*, NUREG/CR-3226[2] was issued in 1983. That report is one of the first comprehensive looks at SBO risk at U.S. commercial nuclear power plants. The report estimated SBO CDFs for two classes of pressurized water reactors (PWRs) and three classes of boiling water reactors (BWRs). The range was 1.5E-6 per reactor calendar year (rcy) to 3.5E-5/rcy. No industry average or typical plant estimate was listed in the report, but based on the mix of plant types presently operating, the industry average for SBO risk would be approximately 2E-5/rcy. The NRC report NUREG-1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*[3], was issued in 1988 and integrated many of the efforts performed as part of TAP A-44. That report again comprehensively addressed the entire industry and included a detailed analysis of LOOP frequencies and a survey of EDG unreliability parameters. NUREG-1032 estimated that SBO CDF at plants ranged from 1E-6/rcy to 1E-4/rcy, with a typical plant value of approximately 1E-5/rcy.

NUREG-1032 provided the technical basis for NRC issuing the SBO rule, 10 CFR 50.63[4], and the accompanying regulatory guide, RG 1.155[5], in 1988. That rule required plants to be able to withstand an SBO for a specified duration and maintain core cooling during that duration. The plant-specific duration depended upon four factors:

- redundancy of emergency AC power sources,
- reliability of those sources,
- frequency of LOOP at the plant, and
- offsite power restoration characteristics.

As a result of the SBO rule, plants were required to enhance procedures and training for restoring offsite and onsite AC power sources. In addition, in order to meet the rule's requirements, some plants chose to make modifications such as adding additional emergency AC power sources [typically EDGs or gas turbine generators (GTGs)]. Finally, emphasis was placed on establishing and maintaining high reliability of the EDGs.

Individual plant examination (IPE) submittals by licensees in the early 1990's provided a follow-on picture of industry SBO risk. These plant risk model results were representative of plant configurations around approximately 1990, so some of the studies reflected plant modifications resulting from the SBO rule, and some did not. The industry average SBO CDF from these IPE submittals was 1.1E-5/rcy[6], with individual plant results ranging from negligible to 6.5E-5/rcy.

Finally, a widespread grid-related LOOP occurred on August 14, 2003. That event resulted in LOOPs at nine U.S. commercial nuclear power plants. As a result of that event, the NRC initiated a comprehensive program that included updating and re-evaluating LOOP frequencies and durations and SBO risk. This report is part of that overall program and focuses on SBO risk.

The purpose of this study is to evaluate the current core damage risk from SBO scenarios at U.S. commercial nuclear power plants. Also covered are non-SBO, LOOP scenarios leading to core damage. All 103 operating commercial nuclear power plants are addressed. Risk is evaluated only for critical operation; risk from shutdown operation is not addressed in this report. Risk is defined as CDF. Other risk measures such as large early release fraction (LERF) are not covered. The standardized plant analysis risk (SPAR) models developed by the NRC for the 103 operating plants were used to evaluate CDF risk.

The structure of the rest of this report is as follows. Section 2 describes the SPAR models and enhancements used for this study. Section 3 summarizes the LOOP frequency and duration results from the companion report *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (draft)*[7]. Characteristics and performance of emergency power systems (EPSs) are described in Section 4. SBO coping characteristics and performance are discussed in Section 5. Baseline SBO (and non-SBO, LOOP) CDF results are summarized in Section 6, and sensitivity results are in Section 7. Finally, summary and conclusions are presented in Section 8.

2. SPAR MODELS

The NRC maintains a set of CDF risk models covering the 103 operating nuclear power plants in the U.S. These SPAR models started out in the mid 1990s as simplified risk models for use in accident sequence precursor (ASP) analyses. However, the current SPAR models are now much more detailed, with expanded support system modeling and a broader range of initiating events.

2.1 SPAR Enhancements

SPAR enhancements performed as part of the ongoing SPAR development program and to support this SBO study are discussed in this section. The enhancements include the areas of reactor coolant pump (RCP) seal leakage models, LOOP frequency and duration models, basic event and initiating event updates, and common-cause failure (CCF) updates.

For RCP seal leakage during loss of seal cooling conditions, the SPAR enhancements are listed below:

- For Westinghouse (WE) plants, the SPAR models now use the RCP seal failure and loss-of-coolant accident (LOCA) models outlined in the recent Westinghouse Owners' Group submittal to NRC, as accepted in the related NRC Safety Evaluation Report or SER[8]. Note that this new model postulates a range of leakage rates for plants with newer RCP O-ring seals, allowing for more time to recover AC power for many of the SBO accident sequences.
- For Combustion Engineering (CE) plants, the SPAR models use the RCP seal failure and LOCA models outlined in the recent CE Owners Group submittal to NRC[9]. (The related NRC SER has not been completed, but the CE submittal is expected to be accepted with few changes or conditions.) The leakage probabilities for this new model are significantly lower than those previously included in the SPAR models.
- For Babcock & Wilcox (B&W or BW) plants, there is no recent or pending submittal to NRC. Therefore, the existing SPAR models were used for B&W plants.
- For General Electric (GE) plants, no changes were made to the SPAR models.

Overall, these changes in the RCP seal leakage models result in lower leakage rates or lower probabilities of high leakage rates, thereby reducing the estimates of SBO risk.

The LOOP frequency and offsite power nonrestoration curve model in SPAR was modified to incorporate the updated information presented in the companion draft LOOP report. This involved subdividing LOOPs into five categories, each with its own frequency and offsite power nonrestoration curve. The combined effects of LOOP frequency and offsite power nonrestoration curve on SBO risk can be examined by reviewing the frequency of exceedance curves as explained in the draft LOOP report. The updated frequency of exceedance composite curve lies above that previously used in SPAR except for the first half hour, so these updates tend to increase the SPAR SBO risk estimates.

Also included in the SPAR enhancements was a comprehensive updating of component failure rates, test and maintenance (TM) outage probabilities (also termed unavailability or UA), and initiating event frequencies to reflect industry average performance centered about the year 2000. The component failure rates were obtained from the Equipment Performance and Information Exchange (EPIX)[10] database maintained by the Institute for Nuclear Power Operations (INPO), as accessed using the NRC-developed Reliability and Availability Database System software[11]. Data for the period 1998 – 2002 were used to develop the failure rates. For train TM outages, data from the Reactor Oversight Process (ROP) Safety System Unavailability (SSU) database (planned and unplanned outages only) for 1998 – 2002 were used[12]. Finally, initiating event frequencies were obtained from the initiating events database maintained by the NRC[13]. The baseline periods used to determine the frequencies varied by initiator but all ended in 2002. In general, almost all of the updated component failure rates, TM outage probabilities, and initiating event frequencies are lower than those previously used in the SPAR models. This reflects general improvements in industry performance from the late 1980s and early 1990s to the present. These enhancements generally reduce the SPAR SBO risk estimates.

Additionally, the CCF modeling in the SPAR models was updated. This effort included regenerating CCF parameters (alpha factors) using the updated CCF database maintained by the NRC[14]. The updated CCF parameters generally are lower than those previously used in SPAR, so again these updates tend to reduce the SPAR SBO risk estimates.

The enhanced SPAR models developed for this study use industry average values for component unreliability, train TM outage probabilities, and initiating event frequencies. An alternative would be to use plant-specific values obtained by updating the industry average results with plant-specific data from a recent period such as three, five, or seven years. This plant-specific alternative was not used based on the following observations. First, it appears that plant-to-plant variation in component performance, train TM, and initiating event frequencies is presently not as large as it was in the past. This is probably the result of programs such as the Maintenance Rule[15] and ROP[16], and more licensee awareness of typical industry performance. If a plant is deviating significantly from the norm, efforts are expended to bring the plant back into the norm. A limited review of component failure data and initiating event data supports this view. For EDGs and TDPs, plant-specific unreliability estimates were generated using the industry averages as priors and EPIX plant-specific data from two periods, 1997 – 1999 and 2001 – 2003. The plants were then ranked from worst to best in terms of the resulting component unreliability estimates. Of the ten plants with the highest unreliabilities for the period 1997 – 1999, only one was also in the ten with highest unreliabilities for 2001 – 2003. This was true for both EDGs and TDPs. In addition, a similar analysis was performed for five initiating events: PWR and BWR general transients, PWR and BWR loss of heat sink, and LOOP. Only approximately two (depending on the type of initiating event) of the ten plants with highest initiating event frequencies using 1997 – 1999 data were also among the ten highest plants using 2001 – 2003 data. This data review supports the view that plants that trend away from industry norm performance generally move back into the norm within a few years. Therefore, if baseline SPAR models were to use plant-specific data, the SPAR inputs would need to be updated frequently to attempt to reflect these short-term deviations from the norm. It is recognized that in a few cases, plant data may reflect continuing performance that is outside of the industry norm. In such cases, plant-specific analyses may need to account for such deviations. In addition, special analyses may require the use of plant-specific data. However, for the purposes of this study, the industry average inputs are appropriate.

The overall characterization of the enhanced SPAR models used to support this study is summarized below:

- up to date in essentially all areas related to LOOP and SBO modeling
- plant-specific design
- standardized modeling
- standardized, industry average data representative of industry performance in the year 2000 (1998 – 2002 data period)
- conservative recovery modeling for LOOP and SBO accident sequences (no convolution to address the potential for failure to run events occurring significantly beyond time zero, and limited credit for component operation and recovery following DC battery depletion).

2.2 SPAR Modeling of LOOP and SBO

A representative LOOP event tree for WE (PWR) SPAR models is presented in Figure 2-1[17]. Following the initiating event, the next top event questions whether the control rods drop into the core to shut down the reactor. If not, the sequence transfers to the anticipated transient without scram (ATWS) event tree for further development. The third top event questions whether the onsite AC EPS successfully starts and provides power to essential buses. If the EPS fails, then the plant is in an SBO situation, and the sequence transfers to a separate SBO event tree (Figure 2-2) for further development. The remaining top events question whether auxiliary feedwater (AFW) is successful, whether a power-operated relief valve (PORV) opens and fails to reclose, whether RCP seal cooling is lost, whether feed and bleed is successful, and whether long-term residual heat removal is successful. Depending upon the combinations of system successes and failures, the remaining accident sequences are flagged as “OK”, meaning the plant is successfully shut down without core damage, “CD”, meaning the sequence ends in core damage, or transferring to additional LOOP event trees. Of special note are the two top events questioning whether offsite power is recovered by two or six hours. Nonrecovery probabilities for these events are determined from the nonrestoration curves presented in the draft LOOP report. (If alternate AC power sources not modeled in EPS are available, then the probability of failure of these sources is factored into this nonrecovery probability using an “AND” gate.) All of the sequences ending with “CD” in Figure 2-1 (and its transfers to other event trees, except for the transfer to the SBO event tree) contribute to what is termed the non-SBO, LOOP CDF for the plant.

The representative SBO event tree is presented in Figure 2-2. The frequency of entering this event tree is termed the SBO frequency, and is the product of the LOOP frequency and the failure probability of the EPS, as modeled in the EPS fault tree. However, the SBO frequency is not the SBO CDF frequency. Only a fraction of SBO events is predicted to lead to core damage, because the plant coping features modeled in the SBO event tree successfully mitigate most such events. The structure of the SBO event tree is similar to the LOOP event tree in terms of systems and functions questioned. However, feed and bleed is not included (pumps available for the feed function require AC power), but RCP seal leakage is questioned. In addition, during SBO conditions, only the auxiliary AFW TDP (or DDP for some plants) is available for core cooling. In addition, no system is available to provide coolant injection if a RCP seal leakage occurs until AC power is recovered. Again, of special note is the top event questioning whether offsite power is recovered by certain times following the LOOP. Depending upon the specific accident sequence, the nonrecovery times are one, two, three, four, six, or seven hours. Nonrecovery probabilities for these events are determined from the nonrestoration curves presented in the draft LOOP report. These nonrecovery probabilities also include credit for starting alternate AC power sources (such as GTGs) not modeled in the EPS fault tree, if such sources exist at the plant. In addition, recovery (including repair) of a failed EDG is modeled as the last top event in the SBO event tree. All of the sequences in the SBO event tree in Figure 2-2 (and in transfers to additional SBO event trees) ending with “CD” contribute to the SBO CDF for the plant.

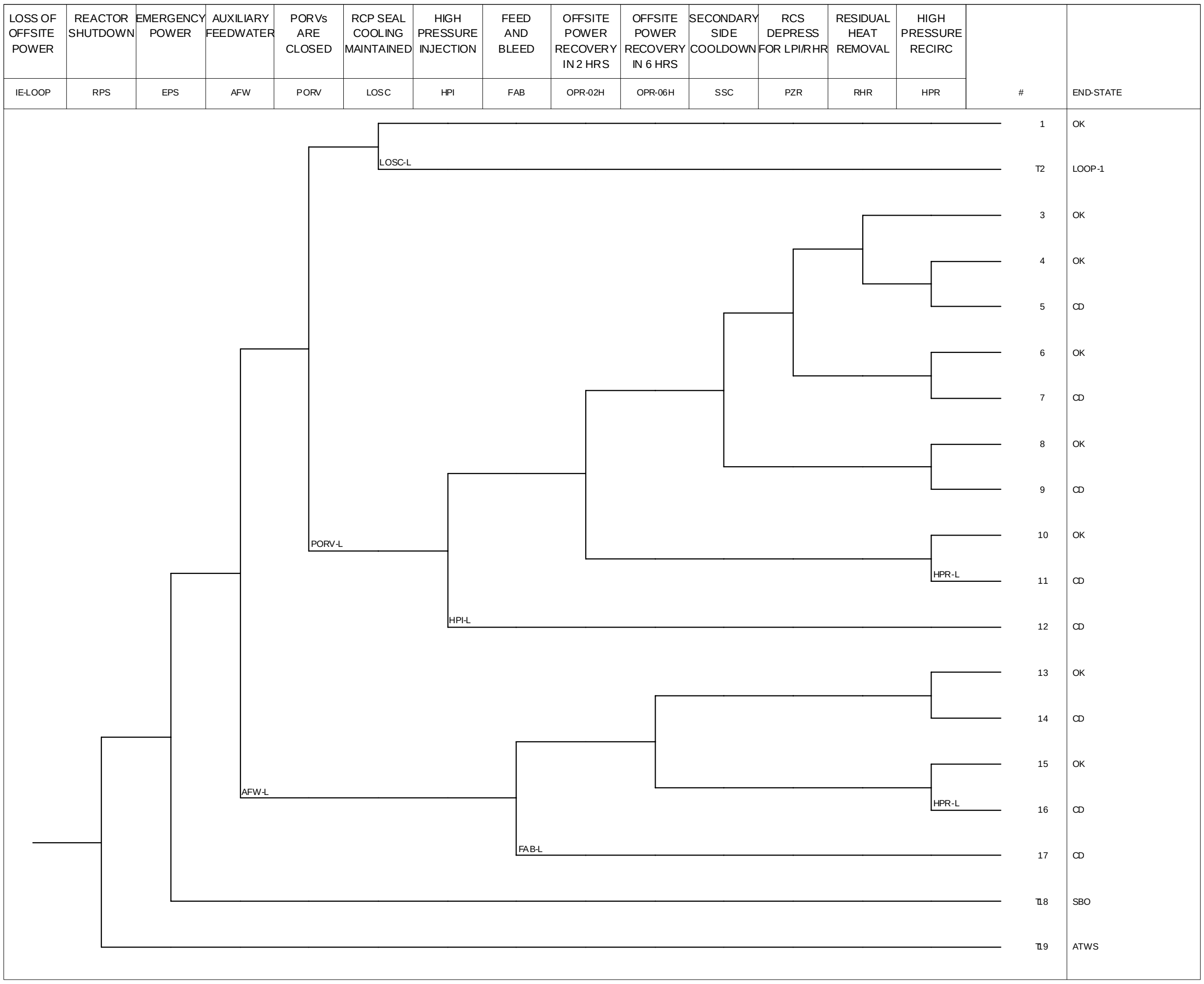


Figure 2-1. Representative LOOP event tree for Westinghouse PWRs.

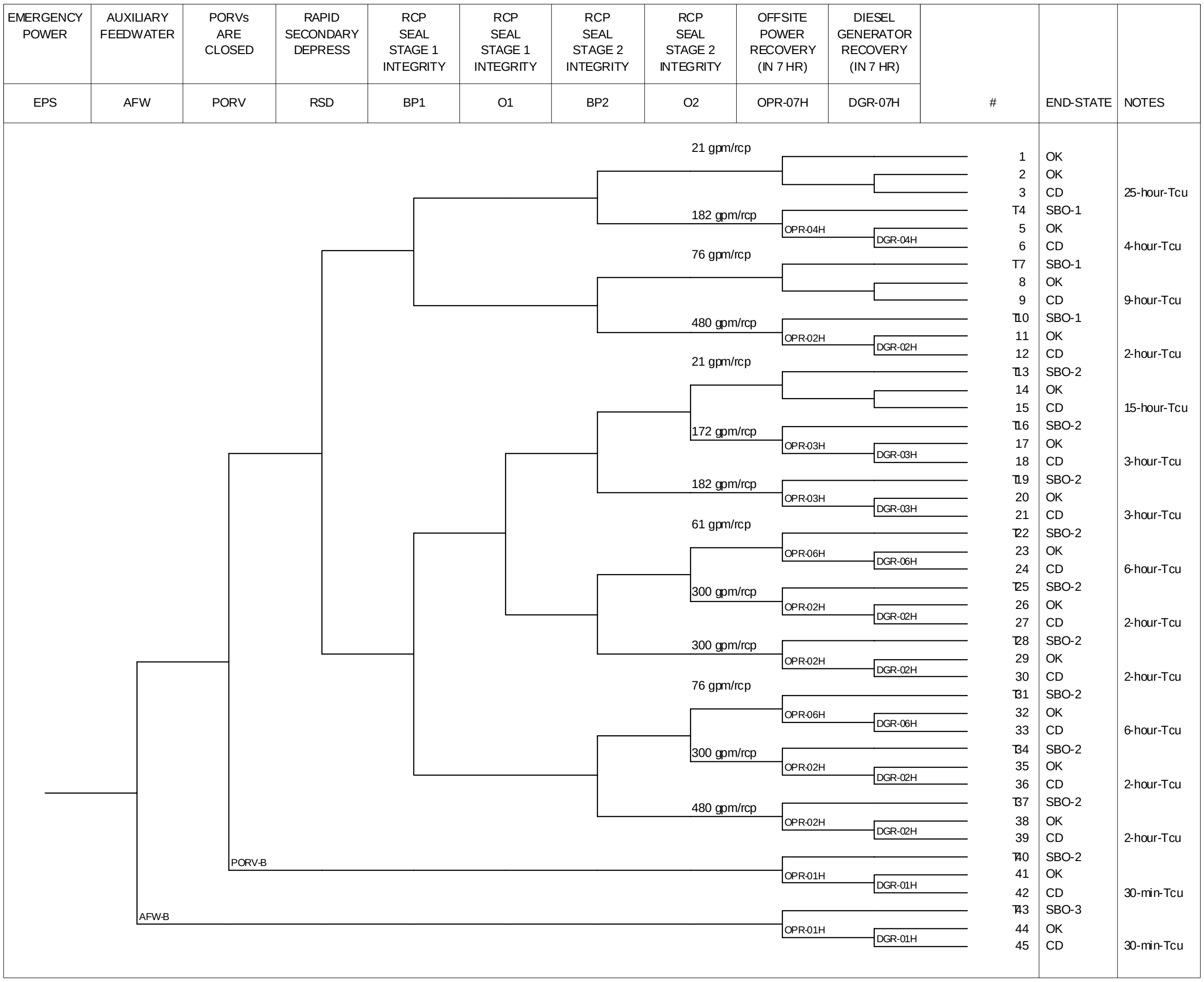


Figure 2-2. Representative SBO event tree for Westinghouse PWRs.

BWR LOOP and SBO event trees are generally similar to the PWR versions in terms of safety functions required. However, for BWRs, RCP seal leakage is not a significant concern during SBO conditions. In addition, most BWRs have two systems available for short-term core cooling – high pressure coolant injection (HPCI) or high pressure core spray (HPCS), and reactor core isolation cooling (RCIC), both of which have TDPs [or a motor-driven pump (MDP) with its own EDG to supply AC power for HPCS] that can function under SBO conditions.

Based on the typical LOOP and SBO event trees within the SPAR models, the following are potentially important contributors to SBO risk:

- LOOP frequency,
- offsite power nonrestoration curve,
- EPS design (redundancy and diversity of onsite AC emergency power sources),
- EPS power source (typically EDGs) reliability and availability,
- nonrecovery (including repair) curve for EDGs,
- RCP seal leakage model (PWRs),
- battery depletion time,

- AC-independent component (TDP, DDP, and HPCS MDP with associated EDGs) reliability and availability, and
- operator errors associated with starting emergency power sources and/or aligning sources to appropriate buses.

Most of these contributors are discussed in the following sections of the report.

3. LOOP FREQUENCY AND DURATION

As indicated earlier in this report, LOOP frequency and duration information have been updated to reflect current performance across the U.S. nuclear power plant industry. Results of that effort are documented in the draft report *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (draft)*. A brief summary of those results is presented in this section.

Industry LOOP frequencies for nuclear power plant critical operation were determined for each of five LOOP event categories: plant centered, switchyard centered, grid related, severe weather related, and extreme weather related. Results are summarized in Table 3-1. These industry LOOP frequencies are considered to represent current performance of the U.S. commercial nuclear power plant industry. The current overall frequency, 3.3E-2/rcry, based mainly on data over the period 1997 – 2003, is lower than past performance. For example, NUREG/CR-5750[18] estimated an overall LOOP frequency of 4.6E-2/rcry for the period 1987 - 1995, NUREG/CR-5496[19] estimated 5.8E-2/rcy for the period 1980 - 1996, while NUREG-1032 estimated 1.1E-1/rcy for the period 1968 – 1985. These estimates are plotted in Figure 3-1.

Table 3-1. Current industry LOOP frequencies.

		LOOP Frequency				
Mode	LOOP Category	Data Group	Events	Reactor Critical Years	Mean Frequency (note a)	Frequency Units (note b)
Critical operation	Plant centered	1997 – 2003	1	629.5	2.38E-03	/rcry
	Switchyard centered	1997 – 2003	5	629.5	8.74E-03	/rcry
	Grid related	1997 – 2003	10	629.5	1.67E-02	/rcry
	Severe weather related	1986 – 2003	4	1508.8	2.98E-03	/rcry
	Extreme weather related	1986 – 2003	3	1508.8	2.32E-03	/rcry
	All	Several			3.31E-02	/rcry

a. The mean is a Bayesian update using a Jeffreys prior. Mean = (0.5 + events)/(critical or shutdown years).
b. Frequency units are per reactor critical year (/rcry).

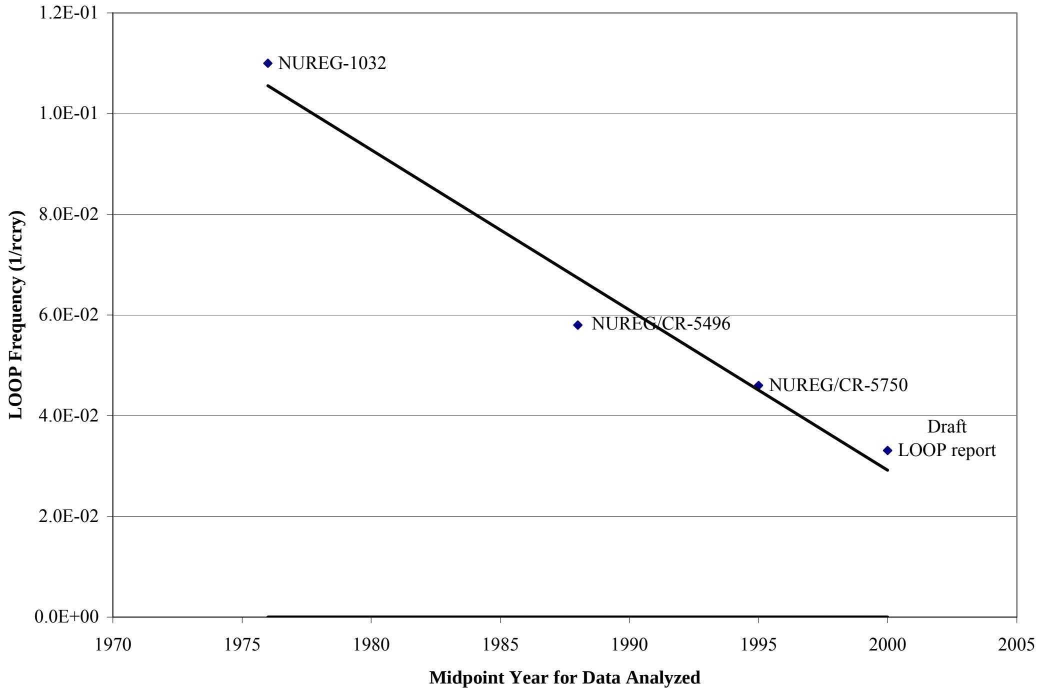


Figure 3-1. Overall industry LOOP frequency trend with time.

Uncertainty distributions for the industry LOOP frequencies are presented in Table 3-2. Presented are the 5%, median, mean, 95%, error factor (95%/median), and shape (α) and scale (β) parameters for the gamma distributions. The overall mean frequency of 3.3E-2/rcry has a lower bound (5%) of 4.8E-3/rcry and an upper bound (95%) of 8.2E-2/rcry. The error factor for this gamma distribution is 3.0.

In the draft LOOP report, the LOOP duration data were converted to probability of exceedance versus duration Weibull curves for each of the five LOOP categories. The Weibull density and cumulative distribution functions used in that report are the following:

$$f(t) = \frac{\alpha}{t}\left(\frac{t}{\beta}\right)^{\alpha} e^{-(t/\beta)^{\alpha}} \tag{1}$$

$$F(t) = 1 - e^{-(t/\beta)^{\alpha}} \tag{2}$$

where t = offsite power restoration time

α = Weibull shape parameter

β = Weibull scale parameter (h).

Table 3-2. LOOP frequency distributions.

Mode	LOOP Category	LOOP Frequency Distribution (note a)							
		5%	Median (50%)	Mean	95%	Error Factor	Gamma Shape Parameter (α)	Gamma Scale Parameter (β, years)	Source (note b)
Critical operation	Plant centered	9.37E-06	1.08E-03	2.38E-03	9.15E-03	8.44	0.500	209.83	CNID
	Switchyard centered	3.44E-05	3.97E-03	8.74E-03	3.36E-02	8.44	0.500	57.23	CNID
	Grid related	6.56E-05	7.59E-03	1.67E-02	6.41E-02	8.44	0.500	29.98	CNID
	Severe weather related	1.17E-05	1.36E-03	2.98E-03	1.15E-02	8.44	0.500	167.64	CNID
	Extreme weather related	9.12E-06	1.06E-03	2.32E-03	8.91E-03	8.44	0.500	215.54	CNID
	All	4.87E-03	2.70E-02	3.31E-02	8.22E-02	3.04	1.737	52.47	Simulation

a. The frequency units for 5%, median, mean, and 95% are per reactor critical year (/rcry).

b. CNID - constrained noninformative distribution, simulation - sum of 5 categories simulated and fit to gamma

The draft LOOP report addressed three possible offsite power restoration times: time to restore offsite power to the switchyard, potential time to restore offsite power to a safety bus, and actual time to restore offsite power to a safety bus. As discussed in that report, the appropriate restoration time for use in PRAs is the potential time. Results of the Weibull curve fits to the potential bus restoration times are summarized in Table 3-3. For plant-centered LOOPs, the mean duration from the Weibull curve fit is 0.5 hour. Switchyard-centered LOOPs have a longer mean duration, 1.3 hours from the curve fit. Grid-related LOOPs have a mean duration of 2.7 hours. Finally, severe- and extreme-weather-related LOOPs have mean durations of 4.7 and 78 hours, respectively.

As an example of how to interpret the nonrestoration curve results summarized in Table 3-3, consider a duration of two hours following initiation of the LOOP. For plant-centered LOOPs, there is a 0.050 probability of not restoring offsite power to a safety bus within that two-hour period. If the LOOP had been switchyard centered, the probability is 0.20. Similarly, the grid-related, severe-weather-related, and extreme-weather-related LOOP probabilities are 0.43, 0.36, and 0.99, respectively. However, the baseline SPAR model uses an overall LOOP frequency (sum of the five LOOP category frequencies) and its associated composite nonrestoration curve. The composite nonrestoration curve is just a frequency-weighted average of the five LOOP category nonrestoration curves. The composite curve presented in Table 3-3 indicates a 0.37 probability of not restoring offsite power to a safety bus within a two-hour period.

Figure 3-2 presents all five probability of exceedance curves in one graph for comparison purposes. The plant-centered LOOPs result in the lowest probabilities of exceedance versus duration, and switchyard-centered LOOPs have the next lowest probabilities. Severe-weather-related LOOPs and grid-related LOOPs have curves that intersect, with severe-weather-related LOOPs having lower probabilities of exceedance up to approximately three hours and higher probabilities after three hours. Finally, the extreme-weather-related LOOPs result in the highest probabilities of exceedance.

LOOP duration data over the entire period 1986 – 2003 were used to generate probability of exceedance versus duration curves for each of the five LOOP categories. Statistical analyses indicated that within each category, there was not a statistically significant difference between the 1986 – 1996 data and the 1997 – 2003 data. However, if all of the LOOP data are combined, a statistically significant increasing trend in durations is observed over the period 1986 – 1996. In contrast, the 1997 – 2003 duration data do not exhibit a significant trend. The results of this trending analysis are presented in Figure 3-3. Finally, if the entire period 1986 – 2003 is considered, there is no statistically significant trend in LOOP durations.

The combined impact of LOOP frequency and LOOP duration on plant risk can be examined by generating frequency of exceedance versus duration curves. These curves are similar to the conditional probability of exceedance curves, but multiplied by the LOOP frequency. The draft LOOP study results for the five LOOP categories are presented in Figure 3-4. Given a plant risk model with constant input parameters except for the LOOP category frequencies and durations, the curves in Figure 3-4 are approximate indications of the relative risk from SBO core damage scenarios from each LOOP category. The higher the curve, the higher the SBO core damage risk.

As indicated in Figure 3-4 for critical operation, grid-centered LOOPs dominate the frequency of exceedance versus duration curves up to approximately six hours. This reflects the relatively high frequency for grid-related LOOPs during critical operation and the moderate durations. Beyond six hours, the extreme-weather-related LOOPs dominate. In addition, up to approximately one and one-half hours, the switchyard-centered LOOPs are important contributors, again mainly because of the relatively high frequency.

Table 3-3. Probability of exceedance versus duration curve fits and summary statistics.

Duration (h)	Probability of Exceedance (Potential Bus Restoration)						
	LOOP Category (Critical or Shutdown Operation)					Critical Operation	
	Plant Centered	Switchyard Centered	Grid Related	Severe Weather Related	Extreme Weather Related	Composite (note a)	Actual Data
0.0	1.000	1.000	1.000	1.000	1.000	1.000	1.000
0.1	0.729	0.875	0.959	0.805	1.000	0.910	0.889
0.2	0.517	0.740	0.895	0.698	1.000	0.816	0.852
0.5	0.276	0.531	0.760	0.564	0.999	0.664	0.667
1.0	0.140	0.363	0.617	0.464	0.998	0.529	0.482
1.5	0.081	0.264	0.510	0.402	0.997	0.438	0.444
2.0	0.050	0.198	0.426	0.358	0.995	0.373	0.278
3.0	0.021	0.119	0.305	0.295	0.991	0.282	0.241
4.0	0.010	0.075	0.222	0.252	0.986	0.224	0.222
6.0	0.003	0.033	0.123	0.195	0.976	0.157	0.148
8.0	0.001	0.016	0.071	0.158	0.964	0.122	0.074
10.0	0.000	0.008	0.041	0.131	0.952	0.102	0.074
12.0	0.000	0.004	0.025	0.112	0.938	0.089	0.074
16.0	0.000	0.001	0.009	0.084	0.909	0.076	0.074
20.0	0.000	0.000	0.004	0.066	0.878	0.069	0.056
24.0	0.000	0.000	0.001	0.053	0.845	0.065	0.037
Weibull Fits							
p value (goodness of fit)	0.306	0.760	0.892	0.667	0.969		
Shape factor (α)	0.610	0.678	0.819	0.422	1.400		
Scale factor (β)	0.330	0.981	2.431	1.872	85.630		
Curve Fit 95% (h)	2.00	4.96	9.29	25.14	187.44		
Curve Fit Mean (h)	0.49	1.28	2.71	5.39	78.04		
Actual Data Mean (h)	0.51	1.31	2.72	4.71	77.91		
Curve Fit Median (h)	0.18	0.57	1.55	0.79	65.91		
Curve Fit 5% (h)	0.00	0.01	0.06	0.00	10.27		

a. The composite curve is a frequency-weighted average of the five individual category curves. Frequencies are presented in Table 3-1.

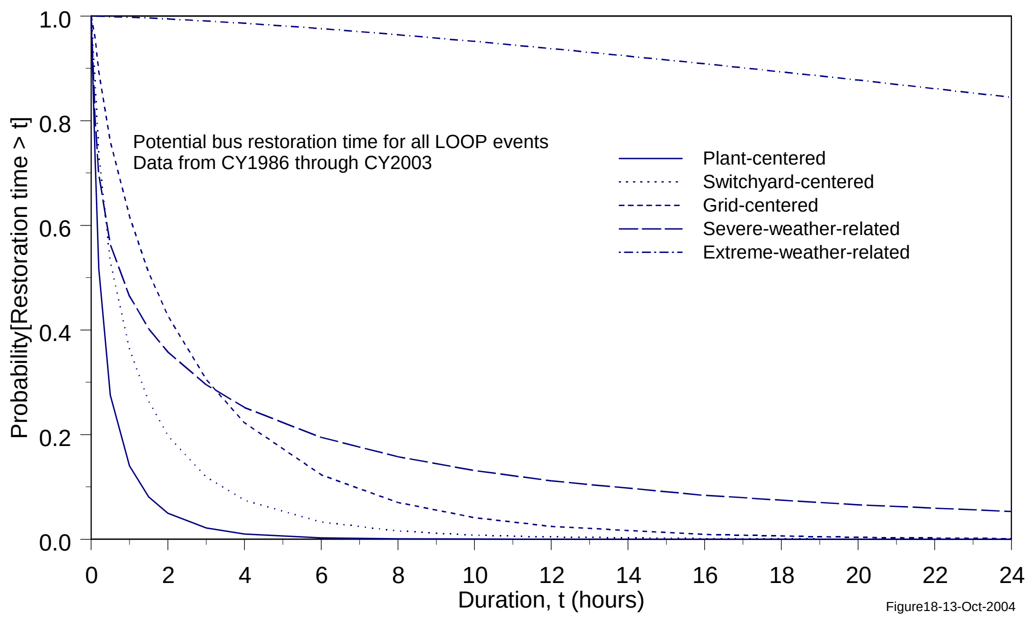
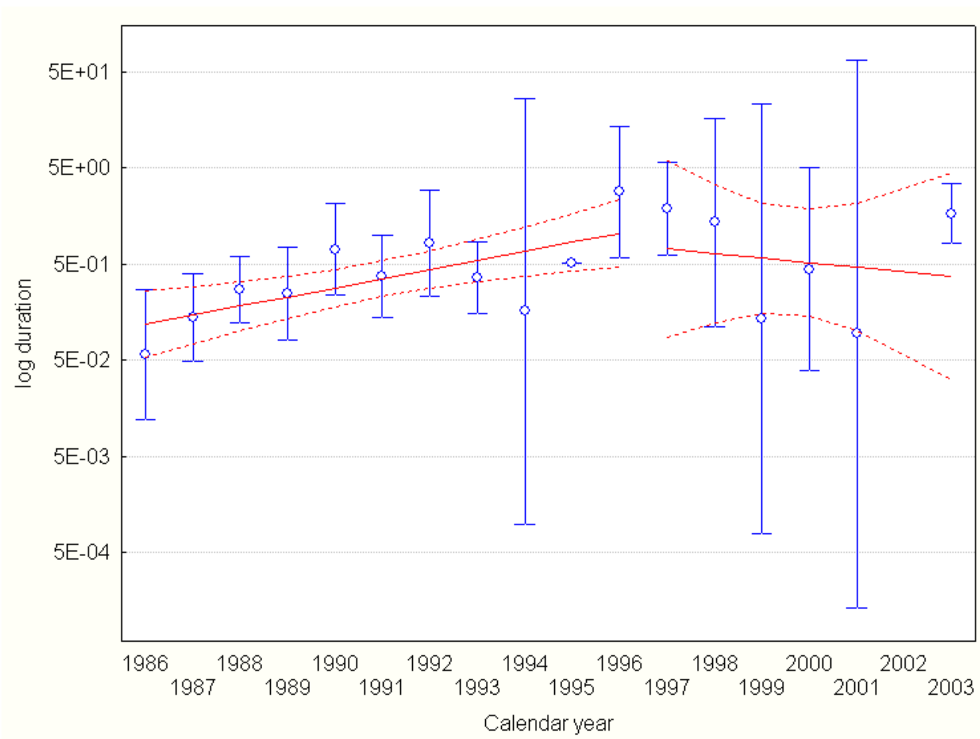


Figure 3-2. Summary of probability of exceedance versus duration curves.



Note – The increasing trend over for 1986 – 1996 is statistically significant (p-value for the slope is 0.016), while the apparently decreasing trend over 1997 – 2003 is not statistically significant (p-value for the slope is 0.736).

Figure 3-3. Trend plot of LOOP duration for 1986 – 1996 and 1997 – 2003.

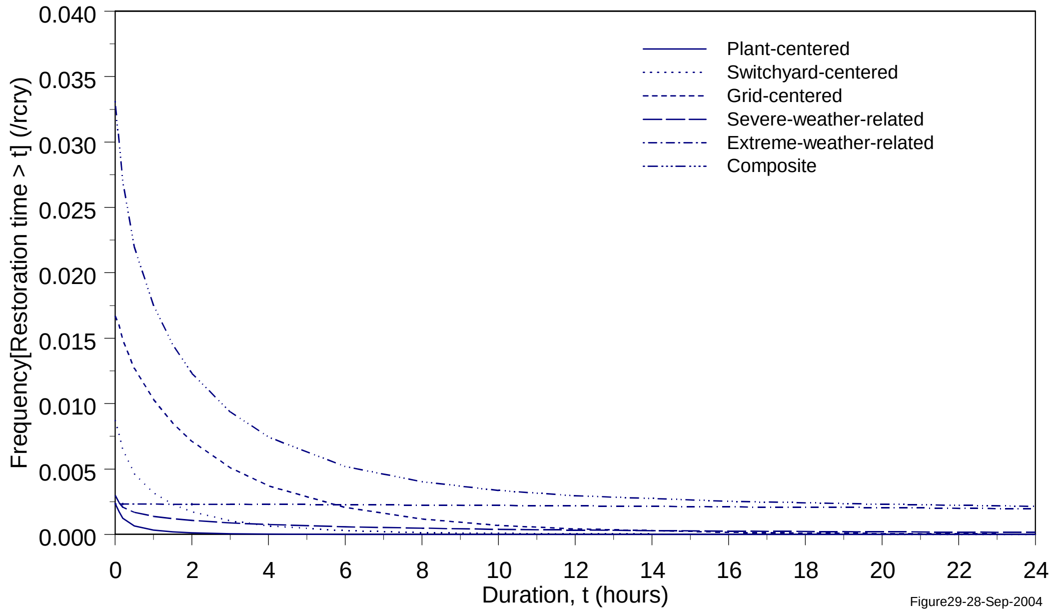


Figure 3-4. Frequency of exceedance versus duration for critical operation.

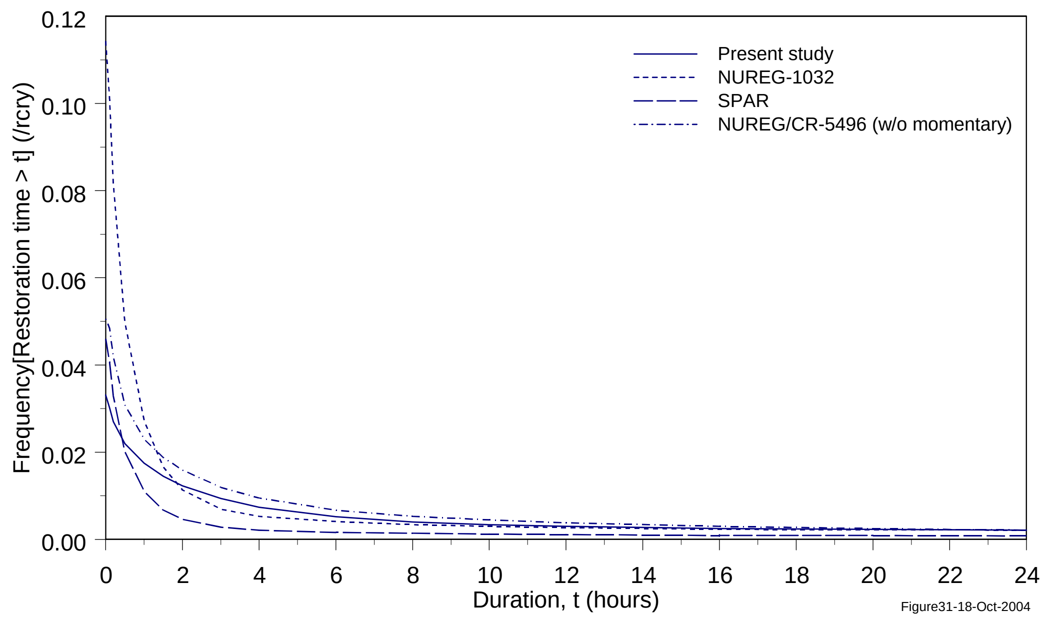


Figure 3-5. Frequency of exceedance versus duration comparison for critical operation.

LOOP Frequency and Duration

4. EPS MODELING AND PERFORMANCE

This section discusses EPS designs, EDG (and other emergency power source) performance, and resulting EPS fault tree quantification results.

4.1 EPS Designs and SPAR Modeling

The EPS is designed to provide backup, onsite AC power to essential buses given a LOOP until offsite power can be restored to the plant. EPS designs vary widely among the 103 U.S. commercial nuclear power plants. A summary of those designs is presented in Table 4-1. Typical EPS designs include two, three, or four EDGs, with only one of the EDGs required for success. However, as indicated in Table 4-1, there are many variations of these typical designs, including shared EDGs and/or the ability to cross-tie to other EDGs (at multi-plant sites), and availability of alternate AC sources such as GTGs or hydro turbine generators (HTGs). In addition, several of the plants require two EDGs for success, rather than one.

SPAR modeling of EPSs incorporates the plant-to-plant design and operational differences indicated in Table 4-1. All AC emergency power sources that either are automatically started and aligned to essential buses given a LOOP or can be manually started and aligned within approximately 30 minutes are included in the SPAR EPS fault trees. Additional emergency power sources such as GTGs or HTGs that require more than 30 minutes to start and align to essential buses are included in other parts of the SBO event tree, typically as additional credit for recovery of AC power. Included in the SPAR EPS fault trees are dependencies such as room cooling, service water cooling, and DC power.

4.2 EDG and Other Emergency Power Source Performance

EDG failure modes in the SPAR models include failure to start (FTS), failure to load and run for one hour (FTLR), failure to run (beyond one hour), and TM outage. In this report, unreliability (UR) is defined to include FTS, FTLR, and FTR. Unavailability (UA) is defined as the TM contribution. Finally, total UR is defined to include both UR and UA. Various CCF events are also included. SPAR models use industry average failure probabilities and rates for FTS, FTLR, and FTR. These were obtained from EPIX data for the period 1998 – 2002, using the RADS software. The data and resulting values are presented in Table 4-2. Also shown in Table 4-2 is a comparison of the EPIX data with unplanned demand (actual undervoltage conditions requiring the EDG to start, load, and run) data obtained from a review of licensee event reports (LERs) over the period 1997 – 2003. The detailed list of EDG unplanned demand data is presented in Appendix A. These unplanned demands are relatively rare, as indicated by the number of demands. Over the period 1997 – 2003, there were 163 such unplanned demands. If the data are limited to 1998 – 2002 to agree with the EPIX data collection period, there were 95 such unplanned demands. This compares with 23983 demands from both tests and unplanned demands from EPIX. Therefore, there are approximately 250 test demands for every unplanned (undervoltage) demand on the EDGs.

Table 4-1. EPS configurations at U.S. commercial nuclear power plants.

<table>
<tr><th colspan="12">EPS Components and Success Criteria</th></tr>
<tr><th colspan="12">Alphabetical by Plant Name</th></tr>
<tr><th rowspan="3">Plant</th><th colspan="3">Safety Class EDGs</th><th colspan="2">Other EDGs</th><th colspan="2">Alternate Power</th><th colspan="2">EPS Success Criterion (note a)</th><th rowspan="3">Other (Late) (note c)</th><th rowspan="3">Comments</th></tr>
<tr><th rowspan="2">Dedicated</th><th colspan="2">Multi-Unit Sites</th><th rowspan="2">SBO</th><th rowspan="2">HPCS</th><th rowspan="2">HTG</th><th rowspan="2">GTG</th><th rowspan="2">Required</th><th rowspan="2">Total (note b)</th></tr>
<tr><th>Cross Tied</th><th>Swing</th></tr>
<tr><td>Arkansas 1</td><td>2</td><td></td><td></td><td rowspan="2">1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Arkansas 2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Beaver Valley 1</td><td>2</td><td></td><td></td><td rowspan="2">1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Beaver Valley 2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Braidwood 1</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Braidwood 2</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Browns Ferry 2</td><td>4</td><td>4</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>4+</td><td></td><td></td></tr>
<tr><td>Browns Ferry 3</td><td>4</td><td>4</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>4+</td><td></td><td></td></tr>
<tr><td>Brunswick 1</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Brunswick 2</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Byron 1</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Byron 2</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Callaway</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2</td><td></td><td></td></tr>
<tr><td>Calvert Cliffs 1</td><td>2</td><td>2</td><td></td><td rowspan="2">1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Calvert Cliffs 2</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Catawba 1</td><td>2</td><td></td><td></td><td rowspan="2">1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Catawba 2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Clinton 1</td><td>2</td><td></td><td></td><td></td><td>1</td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Columbia Nuclear</td><td>2</td><td></td><td></td><td></td><td>1</td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Comanche Peak 1</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Comanche Peak 2</td><td>2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Cook 1</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2</td><td></td><td></td></tr>
<tr><td>Cook 2</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2</td><td></td><td></td></tr>
<tr><td>Cooper Station</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2</td><td></td><td></td></tr>
<tr><td>Crystal River 3</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2</td><td></td><td></td></tr>
<tr><td>Davis-Besse</td><td>2</td><td></td><td></td><td>1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Diablo Canyon 1</td><td>3</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>3</td><td></td><td></td></tr>
<tr><td>Diablo Canyon 2</td><td>3</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>3</td><td></td><td></td></tr>
<tr><td>Dresden 2</td><td>1</td><td>1</td><td rowspan="2">1</td><td>1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Dresden 3</td><td>1</td><td>1</td><td>1</td><td></td><td></td><td></td><td>1</td><td>2+</td><td></td><td></td></tr>
<tr><td>Duane Arnold</td><td>2</td><td></td><td></td><td></td><td></td><td></td><td></td><td>1</td><td>2</td><td></td><td></td></tr>
</table>

Table 4-1. EPS configurations at U.S. commercial nuclear power plants. (continued)

EPS Components and Success Criteria — Alphabetical by Plant Name											
Plant	Safety Class EDGs			Other EDGs		Alternate Power		EPS Success Criterion (note a)		Other (Late) (note c)	Comments
	Dedicated	Multi-Unit Sites: Cross Tied	Multi-Unit Sites: Swing	SBO	HPCS	HTG	GTG	Required	Total (note b)		
Farley 1	1		3					1	2+		
Farley 2	1							1	2+		
Fermi 2	4						1	1	4+		
Fitzpatrick	4							1	4		
Fort Calhoun	2							1	2		
Ginna	2			2 (no credit)				1	2+		
Grand Gulf	2				1			1	2		
Harris	2							1	2		
Hatch 1	2		1					1	2+		
Hatch 2	2							1	2+		
Hope Creek	4						1	2	4	GTG	
Indian Point 2	3						3	1	3	GTG	
Indian Point 3	3			1 (no credit)			3	1	3	GTG	
Kewaunee	2			1 (not in EPS)				1	2	TSC EDG	
LaSalle 1	2	2			1			1	2+		
LaSalle 2	2	2			1			1	2+		
Limerick 1	4							1	4		
Limerick 2	4							1	4		
McGuire 1	2						3	1	2	GTG	
McGuire 2	2							1	2	GTG	
Millstone 2	2			1				1	3		
Millstone 3	2							1	2		
Monticello	2							1	2		
Nine Mile Point 1	2							1	2		
Nine Mile Point 2	2				1			1	2+		
North Anna 1	2	2		1				1	2+		
North Anna 2	2	2						1	2+		
Oconee 1				1 (not in EPS)		2		1	2	SBO	
Oconee 2				1 (not in EPS)		2		1	2	SBO	
Oconee 3				1 (not in EPS)		2		1	2	SBO	
Oyster Creek	2						2	1	2	GTGs	

Table 4-1. EPS configurations at U.S. commercial nuclear power plants. (continued)

EPS Components and Success Criteria											
Alphabetical by Plant Name											
Plant	Safety Class EDGs			Other EDGs		Alternate Power		EPS Success Criterion (note a)		Other (Late) (note c)	Comments
	Dedicated	Multi-Unit Sites		SBO	HPCS	HTG	GTG	Required	Total (note b)		
		Cross Tied	Swing								
Palisades	2							1	2		
Palo Verde 1	2							1	2+		Both GTGs must start for success if all plants at the site experience a LOOP.
Palo Verde 2	2						2	1	2+		Both GTGs must start for success if all plants at the site experience a LOOP.
Palo Verde 3	2							1	2+		Both GTGs must start for success if all plants at the site experience a LOOP.
Peach Bottom 2			4			1		2	4	Hydro	1 EDG does not have cooling without support from another EDG
Peach Bottom 3			4					2	4	Hydro	1 EDG does not have cooling without support from another EDG
Perry	2				1			1	2+		
Pilgrim	2			1 (not in EPS)				1	2	SBO	
Point Beach 1			4				1	1	4+		
Point Beach 2			4					1	4+		
Prairie Island 1	2	2						1	2+		
Prairie Island 2	2	2						1	2+		
Quad Cities 1	1	1	1	2				1	2+		
Quad Cities 2	1	1						1	2+		
River Bend	2				1			1	2?		
Robinson 2	2			1 (not in EPS)				1	2	SBO	
Salem 1	3						1	2	3+		
Salem 2	3						1	2	3+		
San Onofre 2	2	2						1	2+		
San Onofre 3	2	2						1	2+		
Seabrook	2							1	2		
Sequoyah 1	2	2						1	2+		

Table 4-1. EPS configurations at U.S. commercial nuclear power plants. (continued)

EPS Components and Success Criteria											
Alphabetical by Plant Name											
Plant	Safety Class EDGs			Other EDGs		Alternate Power		EPS Success Criterion (note a)		Other (Late) (note c)	Comments
	Dedicated	Multi-Unit Sites		SBO	HPCS	HTG	GTG	Required	Total (note b)		
		Cross Tied	Swing								
Sequoyah 2	2	2						1	2+		
South Texas 1	3							1	3		
South Texas 2	3							1	3		
St. Lucie 1	2	2						1	2+		
St. Lucie 2	2	2						1	2+		
Summer	2							1	2		
Surry 1	1	1	1	1				1	1+		
Surry 2	1	1						1	1+		
Susquehanna 1			5					1	5		
Susquehanna 2								1	5		
Three Mile Island 1	2			1				1	2+		
Turkey Point 3	2	2		5 (shared)				1	2+		
Turkey Point 4	2	2		5 (shared)				1	2+		
Vermont Yankee	2			1 (not in EPS)		1		1	2+	SBO (battery charging and valve operation)	
Vogtle 1	2							1	2		
Vogtle 2	2							1	2		
Waterford 3	2							1	2		
Watts Bar 1	2	2						1	2+		
Wolf Creek	2							1	2		
Totals	202		28	33	8	8	18				

Acronyms: EDG (emergency diesel generator), EPS (emergency power system), GTG (gas turbine generator), HPCS (high-pressure core spray), hydro (hydro turbine generator), SBO (station blackout), TSC (technical support center)

a. The SPAR EPS models include emergency power sources that either start automatically given a LOOP or can be started and aligned within approximately 30 minutes following the LOOP. Listed are PRA success criteria, which may differ from design basis success criteria.

b. A "+" indicates that other emergency power sources are also included in the EPS fault tree, but operation action is required to start and/or align these additional sources to appropriate buses. The operator actions have failure probabilities ranging from very low to 0.5, so the benefit of these additional sources can vary widely, depending upon the human error probabilities.

c. Emergency power sources not included in the SPAR EPSs are credited "later" in the SBO event trees as part of the AC power recovery events.

Table 4-2. SPAR emergency power source failure parameters and supporting data.

Component	Failure Mode	Data 1998 - 2002 (note a)		SPAR Failure Probability or Rate (note b)				Unplanned Demand Data 1997 - 2003 (note c)		
		Failures	Demands or Hours	5%	Median	Mean	95%	Failures	Demands or Hours	Significantly Different from SPAR Data? (note d)
EDG	FTS	98	23983	1.3E-04	2.6E-03	4.0E-03	1.3E-02	1	163	No (limited data)
	FTLR (1/h)	58	21105	4.6E-04	2.5E-03	3.0E-03	7.4E-03	1	163	No (limited data)
	FTR (1/h)	50	61070	2.5E-05	5.1E-04	8.0E-04	2.6E-03	3	1286	No
	TM	N/A	N/A	1.7E-05	3.7E-03	9.0E-03	3.6E-02	0	96	No (limited data)
GTG	FTS	4	120	4.6E-08	4.7E-03	4.0E-02	2.1E-01			No data
	FTLR (1/h)	2	120	2.0E-08	2.1E-03	2.0E-02	1.0E-01			No data
	FTR (1/h)	1	82712	2.0E-11	2.1E-06	2.0E-05	1.0E-04			No data
	TM (note e)	N/A	N/A	6.0E-08	6.1E-03	5.0E-02	2.6E-01			No data
HTG	FTS	3	1788	2.1E-09	2.1E-04	2.0E-03	1.0E-02			No data
	FTLR (1/h)	0	686	7.1E-10	7.3E-05	7.0E-04	3.6E-03			No data
	FTR (1/h)	0	3359	7.1E-11	7.3E-06	7.0E-05	3.6E-04			No data
	TM (note f)	N/A	N/A	5.3E-10	5.4E-05	5.2E-04	2.7E-03			No data

Acronyms: EDG (emergency diesel generator), EPIX (Equipment Performance and Information Exchange), FTLR (fail to load and run for 1 h), FTR (fail to run), FTS (fail to start), GTG (gas turbine generator), HTG (hydro turbine generator), IPE (individual plant examination), LER (licensee event report), N/A (not applicable), PRA (probabilistic risk assessment), ROP (Reactor Oversight Process), SSU (Safety System Unavailability), TM (test and maintenance outage)

a. FTS, FTLR, and FTR data are from EPIX. TM probability is from the ROP SSU (planned and unplanned outages only).

b. The mean failure probability or rate has been rounded.

c. The data cover unplanned (undervoltage) demands on the EDG (GTG or HTG) requiring them to start, load, and run over the period 1997 - 2003. These events were identified from a review of LERs. Events that were easily recovered were not counted as failures.

d. A significance test was performed to determine whether the rate or probability could be the same from both sets of data. If the p-value was greater than 0.05, then the two results were not considered to be statistically different. For the TM comparison, if the unplanned demand estimate obtained using a Bayesian update with a Jeffreys prior lay within the 5% and 95% interval of the SPAR TM distribution, then the data were not considered to be statistically different.

e. From original IPE submittals, but with a reduction of 50% to account for improved performance.

f. The mean value is from the licensee's PRA.

As indicated in Table 4-2, the unplanned demand data were compared with the EPIX data to determine if the two data sets could have the same failure probability or rate. For each of the EDG failure modes – FTS, FTLR, FTR, and TM – the significance tests indicated that the two data sets are not statistically different. However, three of the four failure modes had zero or one failure, so the unplanned demand data for these are limited. In addition, the FTR significance test resulted in a p-value of 0.097, which is close to the 0.05 criterion for declaring the two data sets to be significantly different. Because of the limited EDG unplanned demand data set, it is recommended that such data collection continue, and the results should be periodically reviewed to determine whether these data become significantly different from the EPIX (mainly test) data and ROP SSU data.

The detailed data set for EDG unplanned (undervoltage) demands presented in Appendix A also lists failures that were easily recovered. The single TM event (termed maintenance out of service or MOOS in Appendix A) was quickly recovered. However, even if this event is counted as a failure, the MOOS data are not significantly different from the ROP SSU data. In contrast, the FTLR data indicate five FTLR events, four of which were easily recovered. If the five FTLR events are all considered failures, then the unplanned demand data for FTLR are significantly different from the EPIX data. The recovered events appear to be different from those typically detected during tests and often include sequencer problems. Therefore, the unplanned demands appear to be more of a test on the overall FTLR failure mode than monthly or cyclic tests. However, as noted previously, if only the nonrecovered FTLR events are considered, the two data sets are similar. As additional unplanned demand data are collected, this apparent difference in the FTLR events should be investigated further.

EDG UR has decreased with time, as indicated in Figure 4-1. Shown in the figure are four historical estimates for EDG FTS and EDG total UR (assuming an eight-hour mission time). An eight-hour mission time was chosen so that FTR estimates would not overwhelm the total UR, compared with a 24-hour mission time. In addition, eight hours is an approximate upper bound on battery depletion times for most plants. The total UR includes FTS, FTLR, FTR (up to eight hours), and TM contributions. Figure 4-1 indicates that the total UR estimate has dropped from approximately 1.1E-1 in 1970 from WASH-1400[20] to 2.2E-2 in 2000 (current SPAR estimates). The intermediate values of 5.2E-2 and 7.3E-2 came from NUREG-1150[21] and NUREG/CR-5994[22].

An interesting trend exists for the TM contribution to total UR. The 1970 and 1980 estimates are 6.0E-3. These apparently were based on actual data. However, the 1990 estimate, again based on actual data, was 2.7E-2. (This estimate also agrees with typical EDG TM estimates contained in the IPE submittals in the early 1990s.) Finally, the current SPAR estimate is 9.0E-3, based on ROP SSU data (planned and unplanned outages only). It is not known why EDG TMs were so low in the 1970s and early 1980s. However, it is clear that EDG TM peaked in the late 1980s and early 1990s and then dropped significantly to its current value of 9.0E-3. This same trend exists for some other types of components, so it is not unique to EDGs.

As discussed previously, the SPAR EDG TM baseline of 9.0E-3 is based on ROP SSU data (planned and unplanned outages only) over the period 1998 – 2002. Reporting requirements for the ROP SSU specify that planned component overhaul maintenance performed during critical operation is not to be included in the planned outage hours. However, such outages do contribute to EDG TM as used in plant risk models. The Mitigating Systems Performance Index (MSPI), proposed to replace the ROP SSU, will include such outages in the planned outage hours. (However, support system contributions now reported under the ROP SSU will be reported separately under the support system indicator in the MSPI.) Overall, the MSPI reporting requirements for UA (TM) match those needed for use in plant risk models. To estimate how much of an impact the MSPI reporting requirements may change the ROP SSU results, the EDG UA data submitted by plants in the MSPI pilot program were compared with comparable ROP SSU results. The data submitted by the 20 pilot plants covered the period July 1999 through June

2002. Averaging the EDG UA data, the result was 0.0126. ROP SSU data for the same 20 plants over the same period result in 0.0107. Therefore, for this limited data set, including overhaul maintenances (and removing support system maintenances) increased the UA estimate by 18%. If only MSPI plants with 14-day allowed outage times (in effect during the data collection period) are included, UA increases by 24%. These increases in EDG UA would not significantly affect the EDG total UR and SBO CDF results presented in this report. However, when MSPI EDG UA data begin to be reported, results should be monitored to determine whether the SPAR baseline EDG TM value of 9.0E-3 needs to be modified.

Finally, CCF alpha factors used in the updated SPAR models for EDGs, GTGs, and HTGs are summarized in Table 4-3. These were generated using CCF data for U.S. commercial nuclear power plants over the period 1991 – 2001. Alpha factors are presented for FTS and FTR (including FTLR). The alpha factors for EDGs are based on actual EDG data. Alpha factors for GTGs and HTGs are generic estimates because of insufficient CCF event information for these component types. Several of the EDG parameters can be compared with older estimates from NUREG-1032. For a group size of two, the probability of both EDGs failing is 0.021 for FTS and 0.028 for FTLR and FTR (alpha 2, group size 2 in Table 4-3). The historical estimate from NUREG-1032 is 0.035 (for all failure modes), indicating a higher CCF probability in NUREG-1032. For a group size of three, the probability of all three EDGs failing is 0.0047 for FTS and 0.0074 for FTR (alpha 3, group size 3 in Table 4-3). The comparable value from NUREG-1032 is 0.031, which is again higher than the new SPAR values. The new SPAR CCF parameters reflect an improvement in both CCF performance and CCF modeling compared with the past.

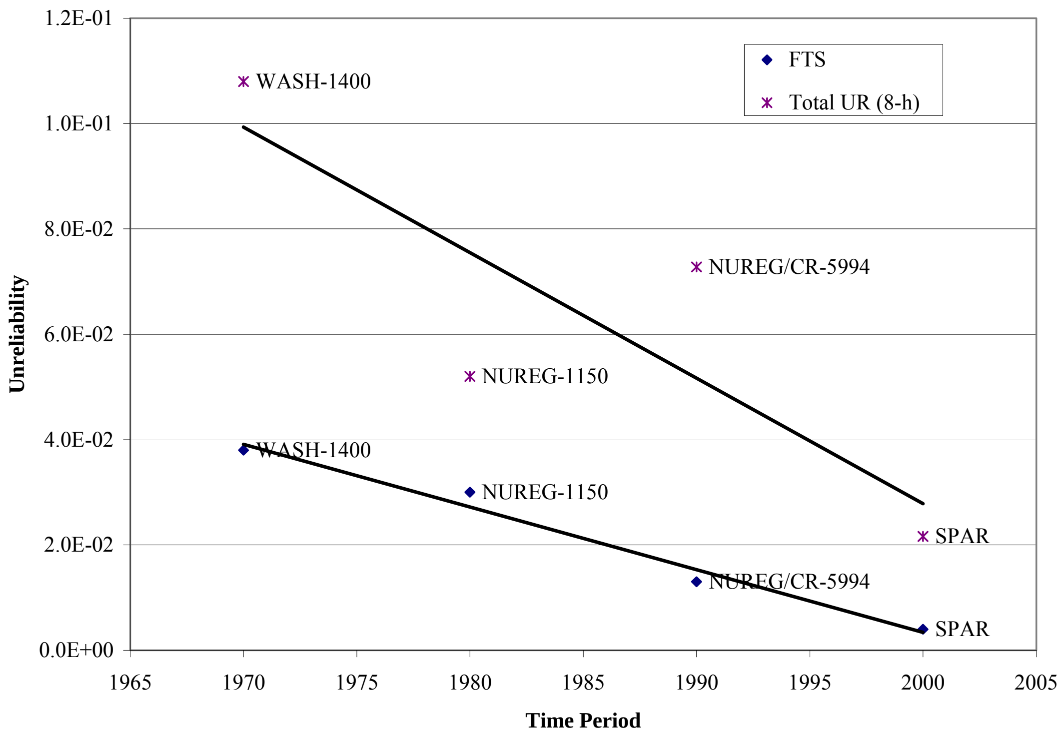


Figure 4-1. EDG FTS and total UR trend with time.

Table 4-3. Emergency power source CCF parameters.

Component Type	Failure Mode	Group Size	Alpha 1	Alpha 2	Alpha 3	Alpha 4
EDG	FTS	2	0.979	0.021		
		3	0.981	0.014	0.0047	
		4	0.982	0.012	0.0048	0.0012
	FTLR and FTR	2	0.972	0.028		
		3	0.975	0.018	0.0074	
		4	0.976	0.015	0.0073	0.0021
GTG and HTG	FTS	2	0.959	0.041		
		3	0.968	0.024	0.0077	
	FTLR and FTR	2	0.962	0.038		
		3	0.971	0.019	0.0094	

Acronyms: EDG (emergency diesel generator), FTLR (fail to load and run for 1 hour), FTR (fail to run), FTS (fail to start), GTG (gas turbine generator), HTG (hydro turbine generator)

4.3 EPS Total UR Results

The EPS fault trees from the updated SPAR models were evaluated for each of the 103 operating U.S. commercial nuclear power plants. Results including uncertainty for each of the plants are presented in Appendix B. Point estimate results are summarized by EPS class and entire industry in Figure 4-2. In the figure, the high, low, and average point estimates are shown for plants within each class and for the industry.

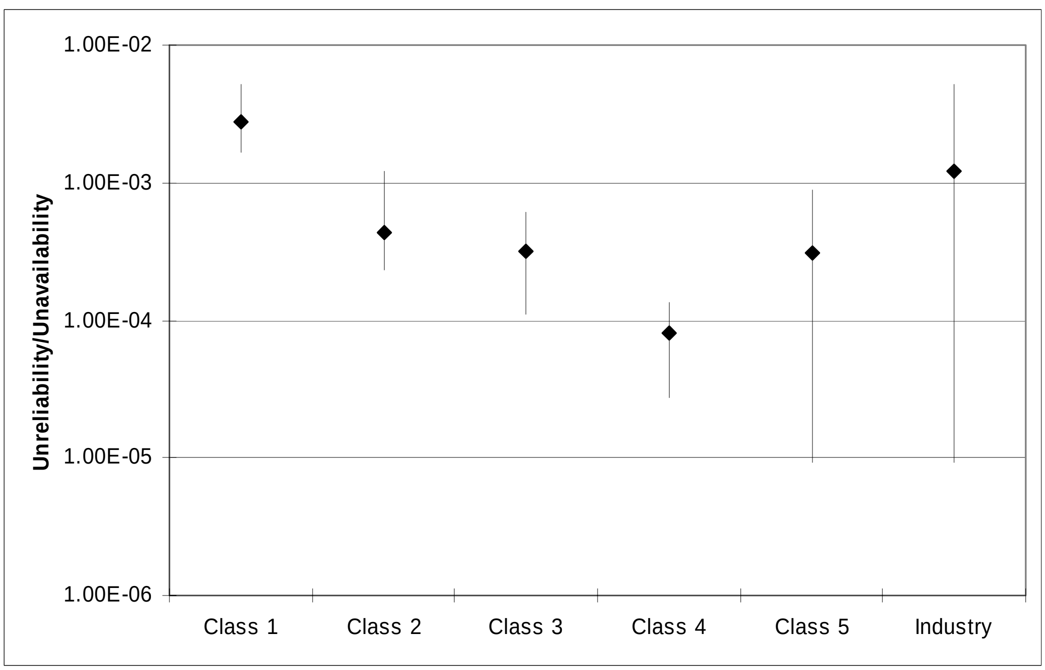


Figure 4-2. EPS total UR point estimate results by class and industry.

EPSs were grouped into five classes based on design considerations and configurations. Class 1 EPSs include two EDGs with a success criterion of one of two. The range of EPS total URs (point estimates) for this class is 1.6E-3 to 5.1E-3. The low value is approximately the lower bound for this type of configuration, using the current SPAR data summarized in Tables 4-2 and 4-3. Higher estimates within this class are the result of additional failures from support systems and/or operator errors. Class 2 EPSs include three EDGs, with a success criterion of one of three. The range of total URs is 2.3E-4 to 1.2E-3. Again, the low value is approximately the lower bound for this type of configuration, while higher values reflect additional failures. EPS designs involving four EDGs and a success criterion of one of four are included in Class 3. The low value in this class, 1.1E-4, is significantly higher than the lower bound estimate of approximately 5.5E-4, indicating that support system failures and operator errors are significant contributors to the total UR. Class 4 includes EPS designs with five or more EDGs. This class includes mainly plants with capability to cross-tie to other plant EDGs (at the same site). Finally, Class 5 includes EPS designs with GTGs and/or HTGs available as backup sources in the near term. Overall, the EPS point estimates range from a low of 9.1E-6 to a high of 5.1E-3. The average of 103 point estimates is 1.2E-3. Uncertainty distributions for each of the EPS classes and the overall industry distribution are presented in Figure 4-3. The uncertainty information in the figure includes the 95%, 5%, and mean. Uncertainty distributions for the EPS classes include both plant design variability (within a class) and parameter uncertainty.

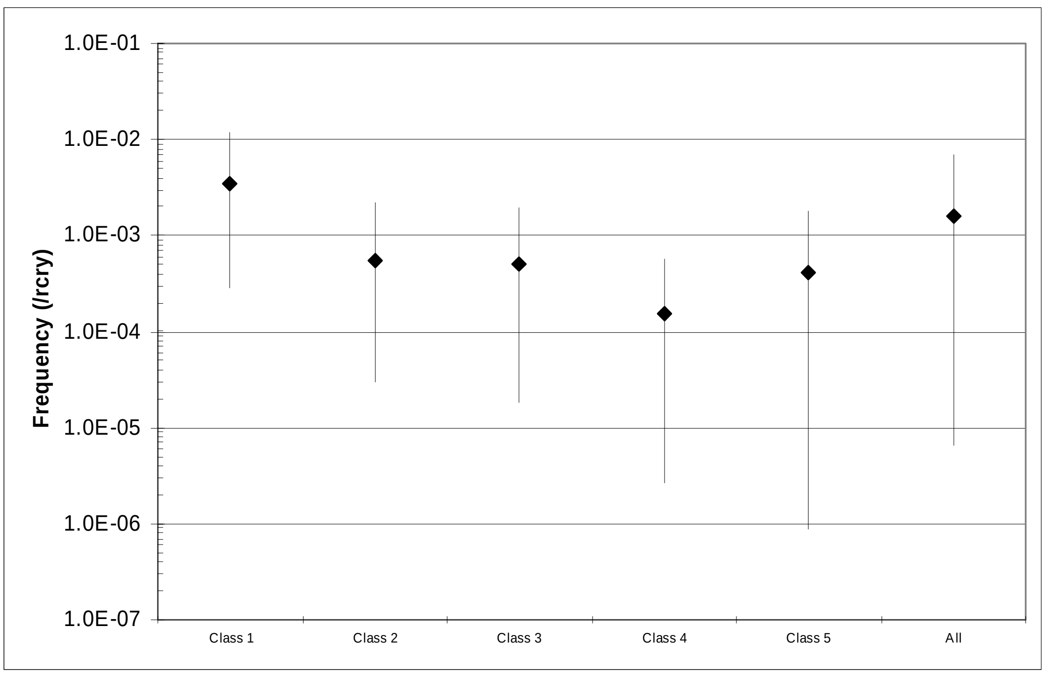


Figure 4-3. EPS total UR uncertainty results by class and industry.

5. SBO COPING FEATURES

As indicated in Section 2, SBO coping features as defined in this report include all of the systems, phenomena, and power recovery events included in the SPAR SBO event tree (Figure 2-2). For PWRs, the AFW system is modeled in the SBO event tree for decay heat removal. Given SBO conditions, only the TDP or DDP is operable. However, these components often require DC power for control, so when the DC batteries deplete, these components typically are assumed to fail if AC power is not recovered by that time. Similarly, for BWRs the HPCI (or HPCS) and RCIC (or isolation condenser) systems are questioned for both coolant injection and decay heat removal. Again, only the TDPs (or MDP with associated EDG) are available during SBO conditions. Figure 5-1 shows how TDP FTS and total UR estimates have dropped as industry performance has improved. The NUREG-1150 estimates cover data over the period before 1970 through approximately 1983. Industry average estimates in the WSRC database[23] cover the period before 1980 through approximately 1990. (Note that the WSRC database does not include TM estimates, so averages from IPE submittals were used.) Finally, the current SPAR estimates are based on EPIX data for the period 1998 – 2002. Total UR (including FTS, FTR <1h, FTR >1h, and TM) is based on an eight-hour mission time to address typical upper bound DC battery depletion times. TDP total UR has dropped from approximately 8E-2 in 1980 to 2E-2 in 2000. Similar trends for the HPCS MDP and associated EDG and for the AFW DDP are presented in Figure 5-2 and Figure 5-3.

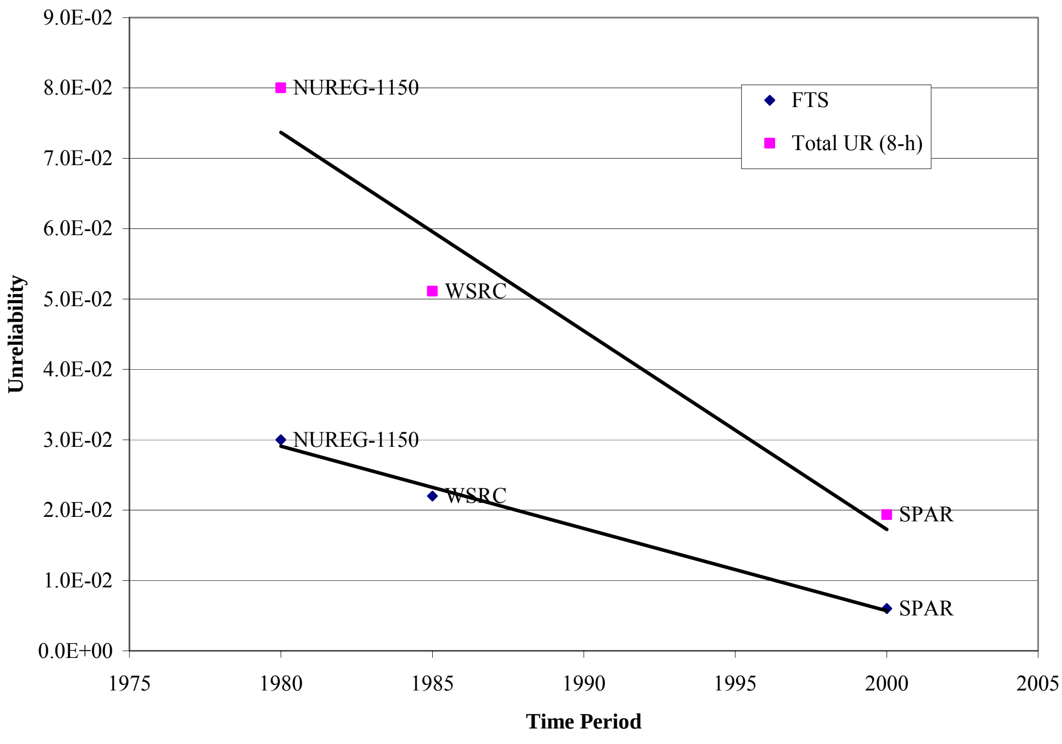


Figure 5-1. TDP FTS and total UR trend with time.

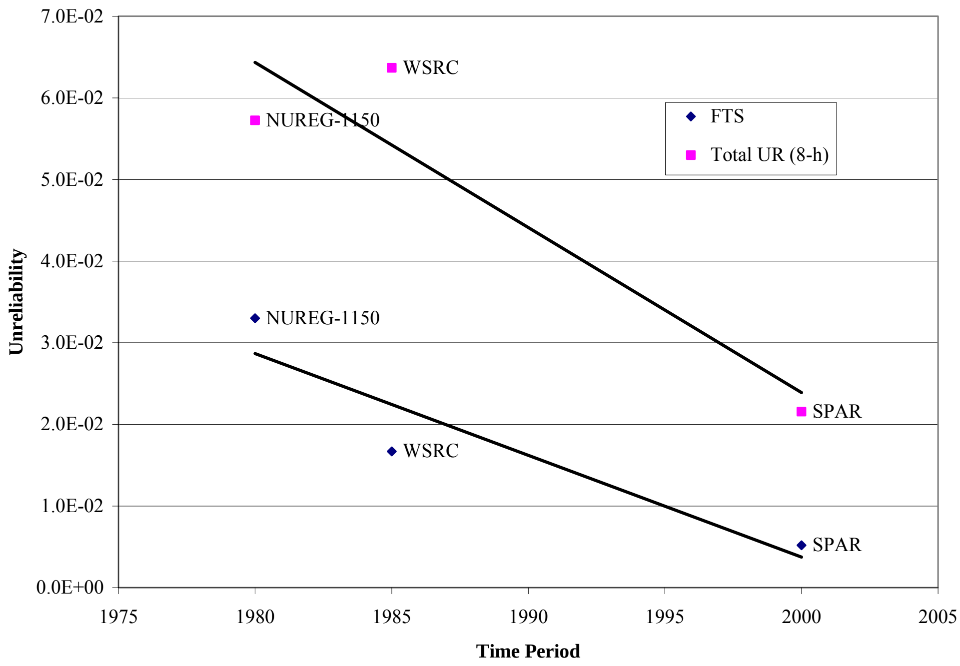


Figure 5-2. HPCS MDP/EDG FTS and total UR trend with time.

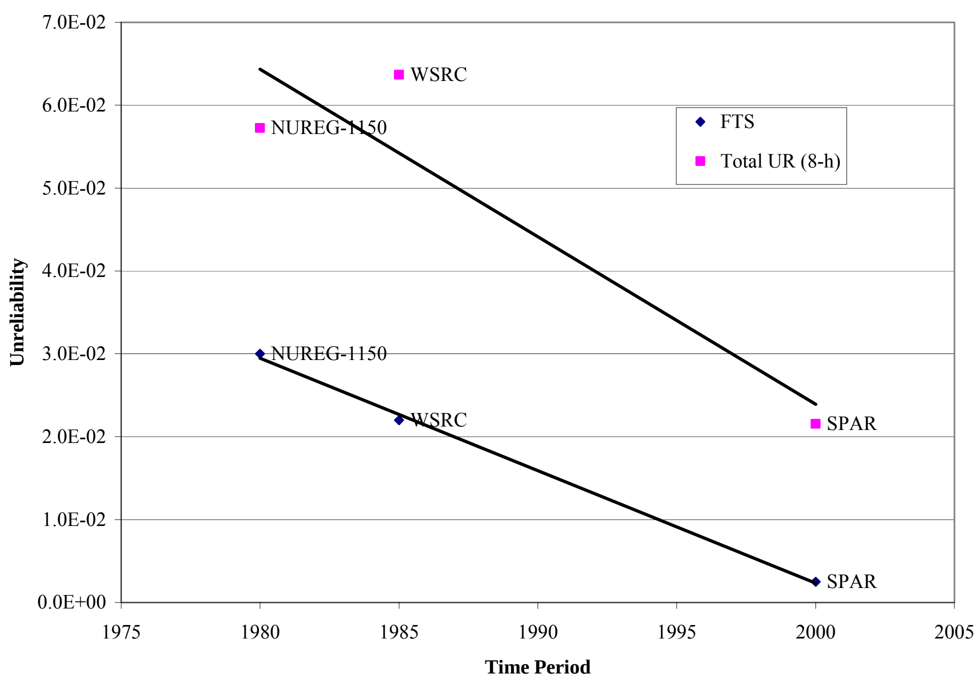


Figure 5-3. AFW DDP FTS and total UR trend with time.

Additional top events in the SBO event tree question whether power-operated relief valves (PORVs) stick open and what size RCP seal leakage develops (if any). As discussed previously, the PWRs do not have coolant injection capabilities during an SBO, so leakage of reactor coolant through PORVs or the RCP seals is important. The time to core uncovery based on these leakage rates generally determines the sequence-specific times before which AC power must be recovered, although some may be based on battery depletion times or boil-off given failure of AFW. The offsite power recovery event in the SBO event tree is quantified on a sequence-specific basis, as indicated in Figure 2-2, with recovery times ranging from one to seven hours (for the example plant). The probability of nonrecovery of offsite AC power for these events is determined from the composite probability of exceedance curve presented in Table 3-3. If alternate AC power sources are available to the plant, then the failure probability of these sources is combined with the Table 3-3 result, using an “AND” gate. These alternate AC power sources are modeled as unavailable up to the time the plant has indicated is required to start the sources, and available beyond that time (but with a failure probability representing the total UR of the alternate AC power source).

Recovery of EDGs is modeled in the final top event in the SBO event tree. This event models the probability of not repairing at least one EDG within the specific time listed for each accident sequence. (These times are the same as those used to model nonrecovery of offsite power.) The few EDG failures resulting from unplanned demands listed in Appendix A do not provide sufficient information to develop a probability of exceedance curve for EDG repair times. Therefore, the model already in SPAR (based on the NUREG-1032 recommendation that a median repair time of four hours is appropriate, given SBO conditions and more than one failed EDG to choose from) was used for this study. Probability of exceedance values from this model are listed in Table 5-1.

Table 5-1. Probability of exceedance for EDG repair times.

Duration (h)	Probability of Exceedance (EDG Repair Times) (note a)
0.0	1.000
0.5	0.917
1.0	0.841
1.5	0.771
2.0	0.707
3.0	0.595
4.0	0.500
6.0	0.354
8.0	0.250
10.0	0.177
12.0	0.125
16.0	0.063
20.0	0.031
24.0	0.016

a. Modeled as an exponential distribution with a median of 4 h

SBO Coping Features

6. BASELINE SPAR CDF RESULTS FOR SBO

Baseline SPAR models covering all 103 U.S. commercial nuclear power plants were quantified to obtain overall CDF (from internal events only), total LOOP CDF (including both SBO and non-SBO contributions), LOOP CDF, SBO CDF, EPS failure probability, and SBO coping failure probability. Plant-specific results are presented in Appendix C. Baseline point estimate CDF results from the SPAR models are summarized in Table 6-1, grouped into eight plant classes as identified in the IPE summary report, NUREG-1560[24]. Also presented in the table are the average results for PWRs, BWRs, and all 103 plants. Figure 6-1 shows the high, low, and average point estimates for the subset of SBO CDF. The extremely low point in the BWR 3/4 category is due to a single plant that has a very reliable EPS system. Without this plant, the minimum value would be 4.1E-08 and would also reduce the band for the BWR and All Plants categories.

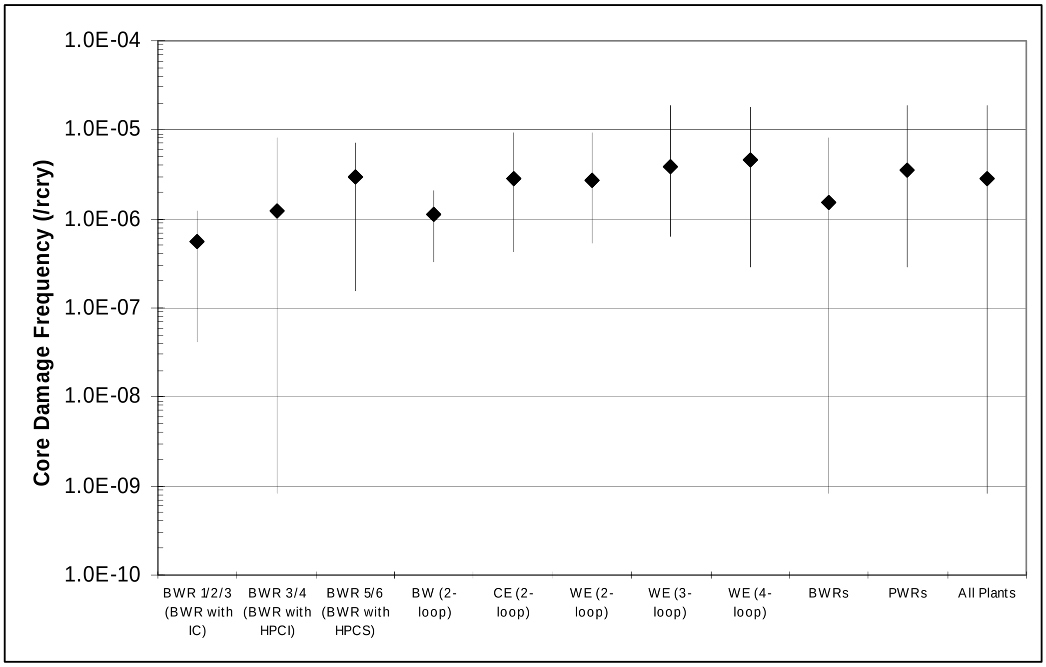


Figure 6-1. SBO CDF point estimate results by class, type, and industry.

The average total CDF for the 103 plants is 1.8E-5/rcry. SBO contributes 2.9E-6/rcry to this total, or 16.1%. SBO CDF risk can be viewed as the product of the LOOP frequency, the EPS failure probability, and the SBO coping failure probability. For all of the plants, the LOOP frequency is 3.3E-2/rcry. Additionally, the average EPS failure probability is 1.2E-3 (as indicated in Section 4). Therefore, the average SBO coping failure probability is 7.2E-2. The SBO coping failure probability is a composite representation of the failure of SBO mitigating features modeled in the SBO event trees.

For all PWRs, the average total CDF is 2.2E-5/rcry, while for BWRs the result is 9.8E-6/rcry. The SBO CDFs are 3.5E-6/rcry and 1.5E-6/rcry, respectively. The SBO contribution to total CDF for both types of plants is approximately 16%.

Plant class results indicate a spread in average total CDF from 1.9E-6/rcry to 2.9E-5/rcry. SBO CDFs range from 5.6E-7/rcry to 4.5E-6/rcry. SBO contributions to total CDF range from 9.5% to 44.3%.

Baseline SPAR CDF Results for SBO

Uncertainty analyses were performed for each of the SPAR model CDF results. Plant-specific results for total CDF and SBO CDF are presented in Appendix C. Plant class, BWR and PWR, and overall industry results are presented in Table 6-2 for SBO CDF. Figure 6-2 shows the 95%, 5%, and mean for SBO CDF. These uncertainty results reflect both plant variability and parameter uncertainty.

Table 6-1. Baseline SPAR CDF point estimate results by class, type, and industry.

Plant Class	Number of Plants	Point Estimates: Total CDF (1/rcry)	Total LOOP CDF (1/rcry)	LOOP (non SBO) CDF (1/rcry)	SBO CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Coping Failure Probability
BW (2-loop)	7	1.17E-05	1.44E-06	3.17E-07	1.13E-06	9.6%	3.31E-02	1.88E-03	1.81E-02
CE (2-loop)	14	2.62E-05	3.29E-06	4.97E-07	2.79E-06	10.7%	3.31E-02	9.18E-04	9.18E-02
WE (2-loop)	6	1.51E-05	3.62E-06	8.70E-07	2.75E-06	18.3%	3.31E-02	6.94E-04	1.20E-01
WE (3-loop)	13	2.93E-05	4.32E-06	4.62E-07	3.85E-06	13.1%	3.31E-02	7.94E-04	1.47E-01
WE (4-loop)	29	2.06E-05	4.77E-06	2.30E-07	4.54E-06	22.0%	3.31E-02	1.27E-03	1.08E-01
BWR 1/2/3 (BWR with IC)	5	1.95E-06	7.69E-07	2.12E-07	5.56E-07	28.6%	3.31E-02	9.02E-04	1.86E-02
BWR 3/4 (BWR with HPCI)	21	1.28E-05	1.92E-06	7.00E-07	1.22E-06	9.5%	3.31E-02	9.14E-04	4.02E-02
BWR 5/6 (BWR with HPCS)	8	6.75E-06	4.35E-06	1.36E-06	2.99E-06	44.3%	3.31E-02	3.02E-03	2.99E-02
PWRs (BW, CE, and WE)	69	2.20E-05	3.94E-06	3.92E-07	3.55E-06	16.2%	3.31E-02	1.12E-03	9.57E-02
BWRs	34	9.76E-06	2.32E-06	7.84E-07	1.54E-06	15.7%	3.31E-02	1.41E-03	3.30E-02
All	103	1.80E-05	3.41E-06	5.21E-07	2.89E-06	16.1%	3.31E-02	1.22E-03	7.17E-02

Acronyms: BW (Babcock & Wilcox), BWR (boiling water reactor), CDF (core damage frequency), CE (Combustion Engineering), EPS (emergency power system), HPCI (high-pressure coolant injection), HPCS (high-pressure core spray), IC (isolation condenser), LOOP (loss of offsite power), PWR (pressurized water reactor), rcry (reactor critical year), SBO (station blackout), WE (Westinghouse)

Table 6-2 Baseline SPAR SBO CDF uncertainty results by class, type, and industry.

Plant Class	Total CDF (1/rcry)					SBO CDF (1/rcry)				
	Point Estimate	**5%**	**Median**	**Mean**	**95%**	**Point Estimate**	**5%**	**Median**	**Mean**	**95%**
BW (2-loop)	1.17E-05	4.57E-07	3.88E-06	1.21E-05	4.48E-05	1.13E-06	3.83E-09	1.86E-07	1.21E-06	4.94E-06
CE (2-loop)	2.62E-05	1.05E-06	9.45E-06	2.72E-05	1.05E-04	2.79E-06	7.56E-09	4.47E-07	3.34E-06	1.48E-05
WE (2-loop)	1.51E-05	1.23E-06	6.20E-06	1.49E-05	5.54E-05	2.75E-06	1.18E-08	5.11E-07	2.81E-06	1.15E-05
WE (3-loop)	2.93E-05	6.09E-07	5.81E-06	2.97E-05	1.20E-04	3.85E-06	1.16E-08	6.36E-07	4.47E-06	1.94E-05
WE (4-loop)	2.06E-05	6.96E-07	5.63E-06	2.12E-05	8.01E-05	4.54E-06	1.81E-08	8.53E-07	5.14E-06	2.17E-05
BWR 1/2/3 (BWR with IC)	1.95E-06	5.31E-08	7.98E-07	2.09E-06	7.80E-06	5.56E-07	1.66E-10	8.17E-08	6.71E-07	2.79E-06
BWR 3/4 (BWR with HPCI)	1.28E-05	1.14E-07	2.06E-06	1.34E-05	3.40E-05	1.22E-06	1.34E-10	9.12E-08	1.36E-06	5.48E-06
BWR 5/6 (BWR with HPCS)	6.75E-06	1.97E-07	2.14E-06	7.24E-06	2.94E-05	2.99E-06	7.33E-09	4.17E-07	3.24E-06	1.48E-05
PWRs (BW, CE, and WE)	2.20E-05	7.12E-07	6.13E-06	2.25E-05	8.60E-05	3.55E-06	1.05E-08	5.81E-07	4.05E-06	1.74E-05
BWRs	9.76E-06	1.08E-07	1.80E-06	1.03E-05	2.82E-05	1.54E-06	2.55E-10	1.30E-07	1.70E-06	7.24E-06
All	1.80E-05	2.80E-07	4.31E-06	1.85E-05	6.80E-05	2.89E-06	2.47E-09	3.76E-07	3.27E-06	1.42E-05

Acronyms: BW (Babcock & Wilcox), BWR (boiling water reactor), CDF (core damage frequency), CE (Combustion Engineering), EPS (emergency power system), HPCI (high-pressure coolant injection), HPCS (high-pressure core spray), IC (isolation condenser), LOOP (loss of offsite power), PWR (pressurized water reactor), rcry (reactor critical year), SBO (station blackout), WE (Westinghouse)

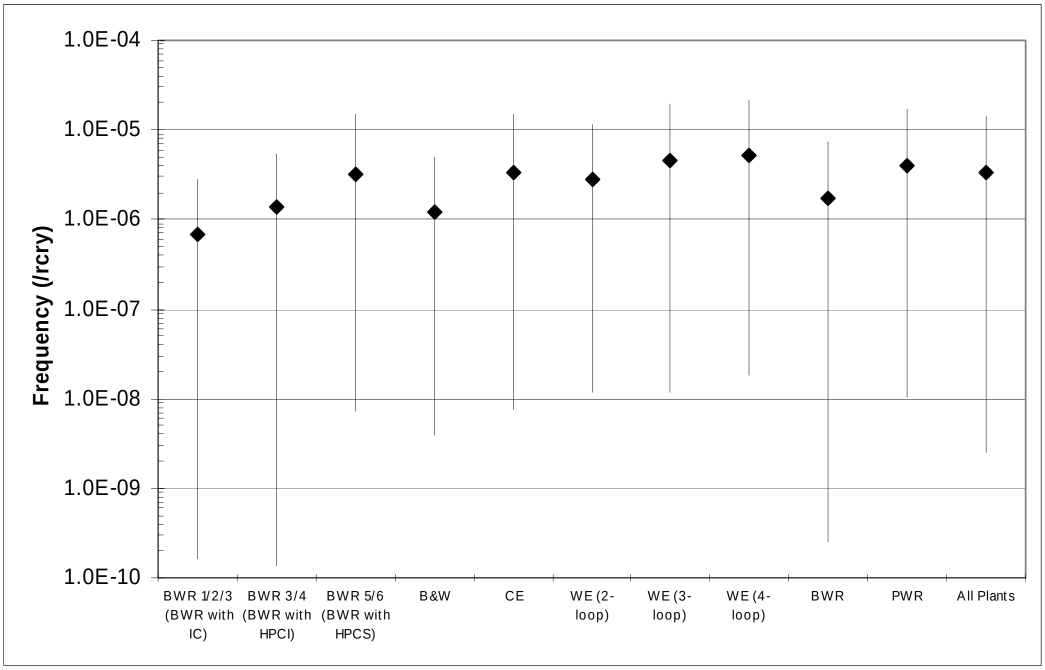


Figure 6-2. SBO CDF uncertainty by class, type, and industry.

SBO CDF contributions from each of the five categories of LOOPs are presented in Table 6-3 and Figure 6-3. The table summarizes the industry average point estimate results for each category, while the figure shows the spread in individual plant point estimate results (high, low, and average). Grid-related LOOPs contribute 50% to the overall SBO CDF. This is to be expected, based on the frequency of exceedance curves for offsite power recovery times (Figure 3-4). In that figure, the grid-related LOOP nonrestoration curve lies above all of the other LOOP category curves until approximately six hours. The next highest contributor to overall SBO CDF is extreme-weather-related LOOPs, at 27%. Again, from Figure 3-4, these LOOPs have a nonrestoration curve that lies above all other categories beyond six hours. Because these LOOPs contribute significantly to the overall SBO CDF, this indicates that offsite power nonrecovery events beyond six hours are significant contributors to SBO CDF. Switchyard-centered and severe-weather-related LOOPs each contribute approximately 10% to the overall SBO CDF. From Figure 3-4, these two curves intersect at approximately three hours, with the switchyard-centered LOOP curve higher up to three hours, so the similar contributions to overall SBO CDF are expected. Finally, the plant-centered curve in Figure 3-4 lies significantly below all of the other curves, so the contribution to overall SBO CDF from these types of LOOPs is expected to be low. The results in Table 6-3 confirm this, indicating only a 1% contribution from plant-centered LOOPs.

Table 6-3. Baseline SBO CDF contributions by LOOP category.

	Point Estimates							
LOOP Category	**Total CDF (1/rcry)**	**Total LOOP CDF (1/rcry)**	**LOOP (non SBO) CDF (1/rcry)**	**SBO CDF (1/rcry)**	**SBO % of Total SBO CDF**	**LOOP Frequency (1/rcry)**	**EPS Failure Probability**	**SBO Coping Failure Probability**
Plant Centered	1.46E-05	5.32E-08	2.30E-08	3.02E-08	1.0%	3.31E-02	1.22E-03	7.48E-04
Switchyard Centered	1.50E-05	4.26E-07	9.49E-08	3.31E-07	11.5%	3.31E-02	1.22E-03	8.20E-03
Grid Related	1.62E-05	1.67E-06	2.23E-07	1.45E-06	50.2%	3.31E-02	1.22E-03	3.59E-02
Severe Weather Related	1.49E-05	3.26E-07	4.93E-08	2.77E-07	9.6%	3.31E-02	1.22E-03	6.86E-03
Extreme Weather Related	1.55E-05	9.15E-07	1.28E-07	7.87E-07	27.3%	3.31E-02	1.22E-03	1.95E-02
All	1.80E-05	3.41E-06	5.21E-07	2.89E-06	100.0%	3.31E-02	1.22E-03	7.17E-02

Acronyms: CDF (core damage frequency), EPS (emergency power system), LOOP (loss of offsite power), SBO (station blackout)

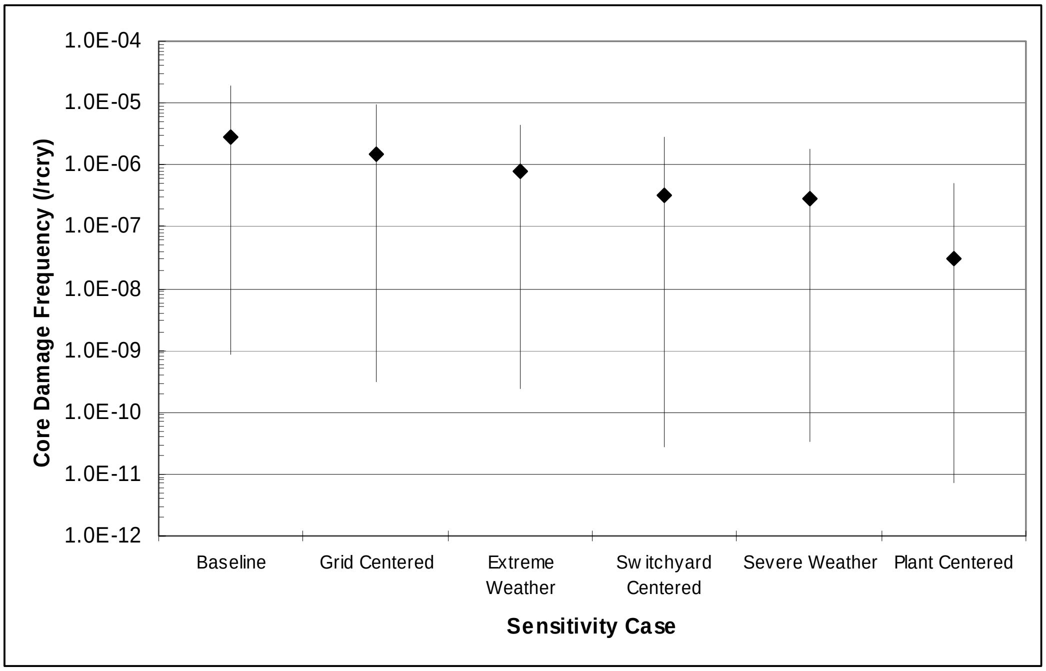


Figure 6-3. Decomposition of overall SBO CDF into LOOP category contributions.

Current SPAR results for SBO CDF are compared with historical estimates in Figure 6-4. Shown in the figure are SBO CDF estimates from four other sources: NUREG/CR-3226 (representing a period ending approximately in 1980), NUREG-1032 (period ending around 1985), Individual Plant Examination (IPE) submittals (period ending around 1992), and updated IPE models (representing approximately 2002). The SPAR results are considered to be more current than the updated IPE models (mainly because of the updated LOOP frequency and duration data, component failure and TM data, initiating event data, and CCF data), so they were placed at 2004 in the figure. SBO CDF results in Figure 6-4 are presented for the eight plant classes, in addition to the overall average. All of the estimates in Figure 6-4 have been normalized to reflect the 103 plants now in operation. In addition, all results are presented in terms of CDF per reactor critical year, although the earlier estimates were based on CDF per reactor calendar year or per site year. Results in Figure 6-4 show a dramatic reduction in SBO frequency estimates over the years and a corresponding reduction in the spread of estimates for the different plant classes. The overall average SBO CDF from NUREG/CR-3226 is 2.1E-5/rcy, while NUREG-1032 indicated an average of 1.0E-5/rcy. IPE submittals resulted in an average of 1.1E-5/rcy, while recent updated IPEs indicate an average of 5.2E-6/rcy. (The updated IPE average is actually for total LOOP CDF, rather than SBO CDF. However, the SPAR results indicate that SBO CDF contributes 85% to the total LOOP CDF. Therefore, the results presented in Figure 6-4 for the updated IPE models are probably close to the actual SBO CDF results.) In comparison, the current SPAR result is 2.9E-6/rcry.

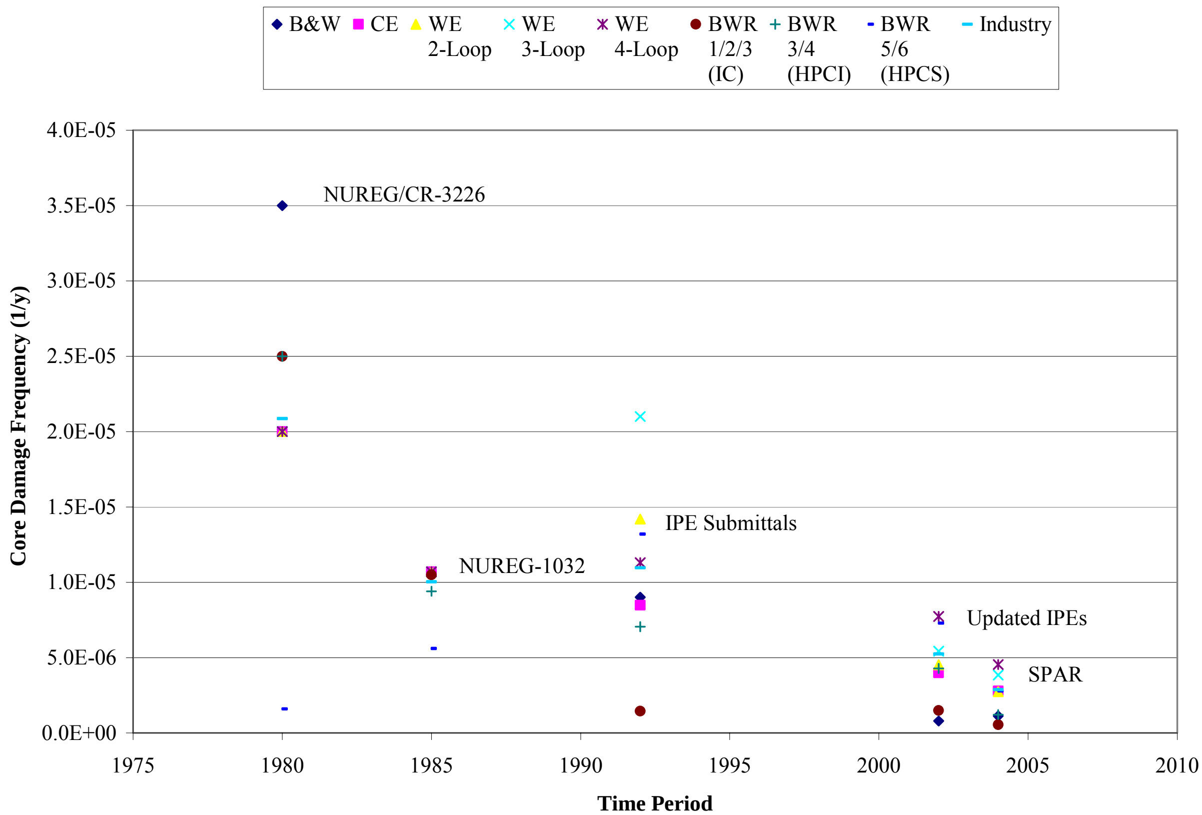


Figure 6-4. Summary of historical estimates of SBO CDF.

7. SENSITIVITY ANALYSIS RESULTS

Sensitivity analyses were performed in four general areas: EDG modeling and performance, offsite power recovery times, seasonal variations, and historical input data. In addition, SBO results were calculated using plant-specific LOOP frequencies. Each of these types of sensitivity analyses is discussed below. Sensitivity analysis results are summarized in Table 7-1. All sensitivity results presented in this section are point estimates. No uncertainty analyses were performed for the sensitivity cases. A description of each of the sensitivity case inputs to the SPAR models is presented in Appendix D.

To evaluate the sensitivity of the industry SBO CDF baseline results to EDG modeling and performance, four cases were identified. To identify the sensitivity to EDG performance, two cases were used, one with all four EDG total UR parameters (FTS, FTLR, FTR, and TM) increased by a factor of two, and the other with all four parameters reduced by a factor of two. These two cases identify how sensitive the SBO CDF results are to increased or degraded EDG performance (relative to the performance reflected in the EPIX data over the period 1998 – 2002). If EDG performance degrades by a factor of two (EDG parameters multiplied by two), the industry average SBO CDF increases from 2.9E-6/rcry to 8.3E-6/rcry. If EDG performance is improved by a factor of two (EDG parameters divided by two), the SBO CDF decreases from 2.9E-6/rcry to 1.3E-6/rcry. For the first case, increasing the EDG parameters by a factor of two increases SBO CDF by approximately a factor of three. This behavior is explained by typical cut sets for the EPS fault tree. Because EPSs require more than one EDG to fail in order to fail the system, dominant cut sets involve both CCF events (which increase linearly with increasing EDG failure probability) and combinations of independent EDG failures (which increase by powers of two, three or four, depending upon the number of EDGs and the success criterion). Therefore, increasing the EDG total UR by a factor of two effectively increases the SBO CDF by a factor of three. However, reducing the EDG total UR by a factor of two does not decrease the SBO CDF by a factor or three (the factor is closer to two) because other EPS failures (support systems and human errors) become significant contributors.

An additional EDG sensitivity case involves approximating a potential increase in EDG TM that could occur for plants with NRC approval for 14-day EDG outages during critical operation. This situation was modeled by assuming such outages occur once every two cycles (36 months). This extra TM outage contribution was added to the baseline probability of 9.0E-3 (which corresponds to approximately 3.3 days/rcry) to obtain a new TM value of 2.3E-2. As indicated in Table 7-1, this sensitivity case increased the SBO CDF from 2.9E-6/rcry to 3.8E-6/rcry.

The final EDG sensitivity case involved changing the EDG mission time in the SPAR models from 24 hours to eight hours. The SPAR models before the enhancements discussed in Section 2 were implemented included plant-specific EDG mission times based on plant-specific offsite power nonrestoration curves derived from information in NUREG-1032. Those mission times were based on the duration at which 95% of the LOOPs were recovered (offsite power was restored). Resulting plant-specific EDG mission times ranged from less than two hours to beyond eight hours. The draft LOOP report presents updated LOOP and offsite power restoration results indicating much longer durations for LOOPs and less variation between plants. Using the industry average results from that study, a mission time based on the 95% criterion just discussed would be approximately 24 hours. (The composite nonrestoration curve presented in Table 3-3 indicates a nonrestoration probability of 0.065 at 24 hours, which is close to 0.05.) Therefore, the updated base SPAR models all use 24 hours for the EDG mission times. Changing this mission time to eight hours resulted in the SBO CDF dropping from 2.9E-6/rcry to 1.4E-6/rcry.

All four EDG sensitivity case results are also summarized in Figure 7-1. In that figure, the individual plant SBO CDFs are presented (high, low, and average).

Table 7-1. Sensitivity analysis results summary.

Sensitivity Case	Total CDF (1/rcry)	Total LOOP CDF (1/rcry)	LOOP (non SBO) CDF (1/rcry)	SBO CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Coping Failure Probability
Baseline	1.80E-05	3.41E-06	5.21E-07	2.89E-06	16.1%	3.31E-02	1.22E-03	7.17E-02
EDG Total UR Doubled	2.38E-05	9.22E-06	9.50E-07	8.27E-06	34.8%	3.31E-02	3.27E-03	7.64E-02
EDG Total UR Halved	1.62E-05	1.67E-06	3.75E-07	1.29E-06	8.0%	3.31E-02	5.85E-04	6.69E-02
EDG 14-Day Outages	1.90E-05	4.44E-06	6.22E-07	3.82E-06	20.1%	3.31E-02	1.80E-03	6.39E-02
EDG 8-Hour Mission Time	1.64E-05	1.81E-06	3.97E-07	1.42E-06	8.7%	3.31E-02	6.77E-04	6.33E-02
30 Minute Nonrestoration Curve	1.86E-05	4.09E-06	5.43E-07	3.55E-06	19.0%	3.31E-02	1.22E-03	8.81E-02
Actual Bus Nonrestoration Curve	2.02E-05	5.63E-06	6.93E-07	4.94E-06	24.5%	3.31E-02	1.22E-03	1.23E-01
Summer and EDG 14-Day Outages (note a)	2.79E-05	1.34E-05	1.72E-06	1.16E-05	41.7%	7.28E-02	3.04E-03	5.25E-02
Non-Summer and EDG 14-Day Outages (note b)	1.53E-05	7.57E-07	1.00E-07	6.57E-07	4.3%	4.70E-03	2.46E-03	5.69E-02
NUREG-1032 Inputs	2.67E-05	1.22E-05	2.32E-06	9.86E-06	36.9%	1.14E-01	3.74E-03	2.31E-02
NUREG-1032 Inputs (w/o EDG)	1.89E-05	4.32E-06	1.28E-06	3.03E-06	16.1%	1.14E-01	1.22E-03	2.19E-02
NUREG/CR-5496 Inputs	2.40E-05	9.47E-06	1.16E-06	8.31E-06	34.6%	5.06E-02	2.71E-03	6.06E-02
NUREG/CR-5496 Inputs (w/o EDG)	1.91E-05	4.51E-06	7.52E-07	3.75E-06	19.7%	5.06E-02	1.22E-03	6.10E-02
Plant-Specific LOOP Frequencies	1.78E-05	3.27E-06	5.12E-07	2.76E-06	15.5%	3.29E-02	1.22E-03	6.90E-02

Acronyms: CDF (core damage frequency), EDG (emergency diesel generator), EPS (emergency power system), LOOP (loss of offsite power), SBO (station blackout), UR (unreliability)

a. This applies only to the five summer months (May through September).

b. This applies only to the seven non-summer months.

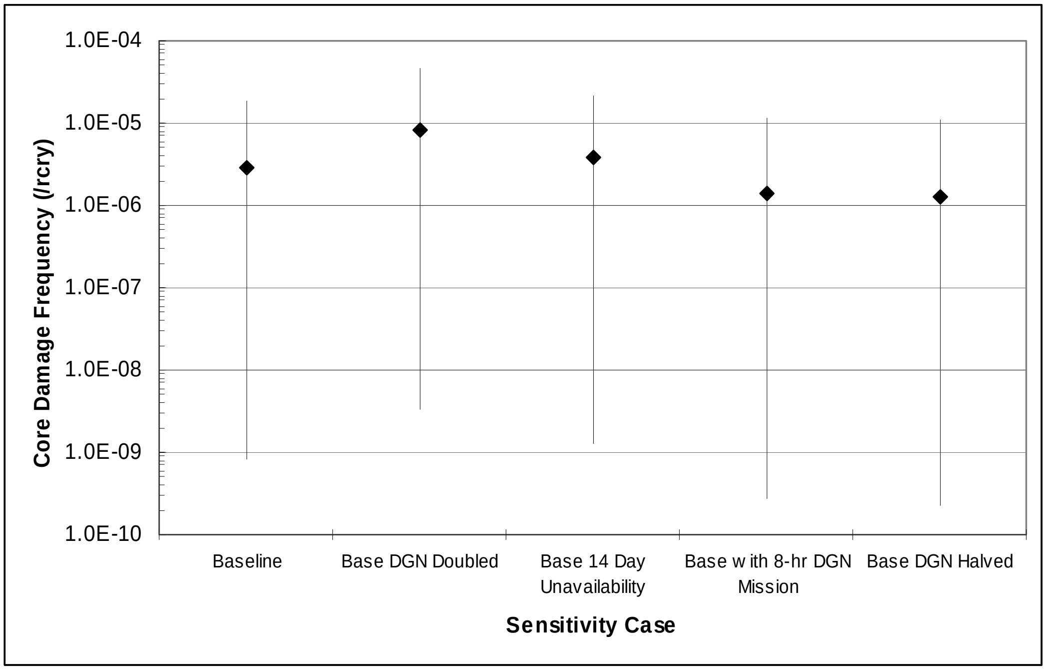


Figure 7-1. SBO CDF results for EDG sensitivity cases.

Another set of sensitivity analyses deals with variations in the offsite power nonrestoration curves documented in the draft LOOP report. As discussed previously, the nonrestoration curves based on potential time to restore offsite power to an emergency bus are most appropriate for use in the baseline SPAR models. Because there was some uncertainty in estimating these potential times to restore offsite power, the draft LOOP report included a sensitivity analysis in which 30 additional minutes were added to potential times that were uncertain. The resulting composite nonrestoration curve from that report was inserted into the SPAR models and the change in SBO CDF determined. As indicated in Table 7-1, the SBO CDF increased from 2.9E-6/rcry to 3.5E-6/rcry. An additional sensitivity was performed using the nonrestoration curves derived from actual bus restoration times in the draft LOOP report. (These times are often much longer than the potential bus restoration times, because plants often run their EDGs beyond the time at which power is restored to the switchyard.) Using the actual bus restoration times increased the SBO CDF to 4.9E-6/rcry. Both sensitivity cases are summarized in Figure 7-2.

Two seasonal sensitivity cases were also evaluated. The draft LOOP report indicated that the overall LOOP frequency varies by time of year. In that report, summer was defined as the period May through September, while non-summer covered the remainder of the year. The summer LOOP frequency was determined to be approximately 2.2 times higher than the annual average, while the non-summer frequency was approximately 7 times lower. Given these two very different seasonal frequencies, a question arises as to how much of an additional impact the EDG 14-day outages might have on the results if such outages were to occur only during the summer or only during the non-summer months. Therefore, one sensitivity case was run using the summer LOOP frequency and the EDG TM value reflecting 14-day outages occurring during the summer. The impact on SBO CDF was an increase from 2.9E-6/rcry to 1.2E-5/rcry (Table 7-1). However, that increase applies to only five of the 12 months in a year. The annual average impact on SBO CDF for this sensitivity would be

(1.16E-5/rcry)(5/12) + (2.89E-6/rcry)(1/7)(7/12) = 4.83E-6/rcry + 2.41E-7/rcry = 5.07E-6/rcry.

Therefore, performing 14-day EDG outages only during the summer (assuming such outages occur approximately once every two cycles) increases the SBO CDF from 2.9E-6/rcry to 5.1E-6/rcry.

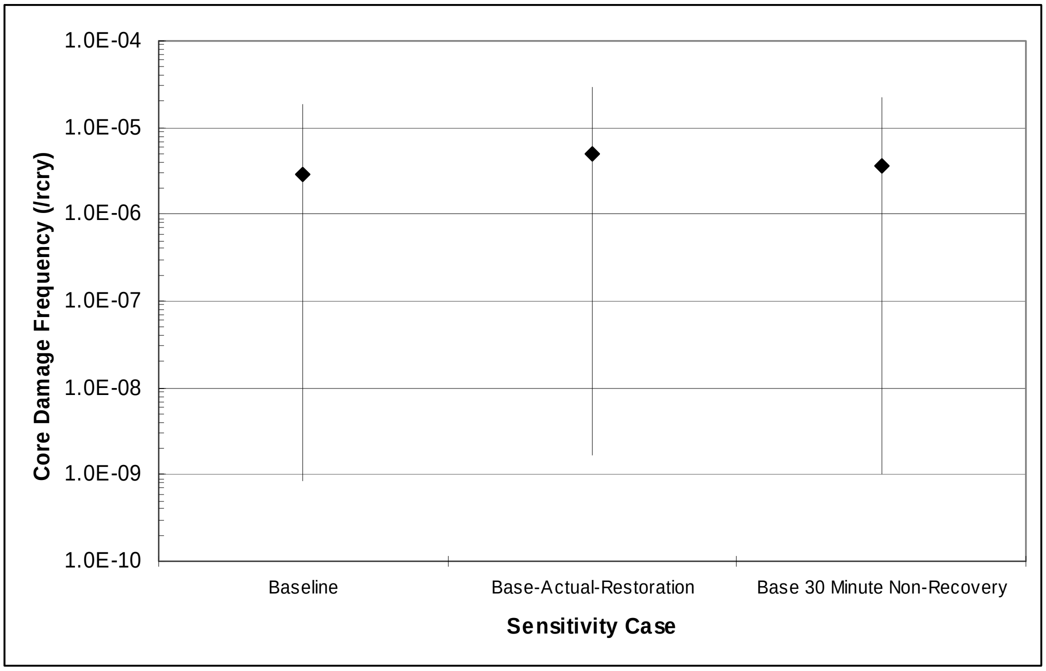


Figure 7-2. SBO CDF results for offsite power nonrestoration curve sensitivity cases.

The other seasonal sensitivity involved performing EDG 14-day outages only during the non-summer months. The resulting SBO CDF is 6.6E-7/rcry (Table 7-1), which applies only to the seven non-summer months. In this case, the annual average impact on SBO CDF is

(6.57E-7/rcry)(7/12) + (2.89E-6/rcry)(2.2)(5/12) = 3.83E-7/rcry + 2.65E-6 = 3.03E-6/rcry.

In this case, allowing EDG 14-day outages (with the frequency of such events being approximately once every two cycles) but only during non-summer months increases the SBO CDF from 2.9E-6/rcry to 3.0E-6/rcry, which is a negligible increase.

To determine how historical estimates for LOOP frequency, offsite power recovery, and EDG performance affect the baseline results, four sensitivity cases were analyzed. Two involved modifying the baseline SPAR models by incorporating NUREG-1032 inputs. One of these two included NUREG-1032 data for all three types of inputs, while the other used NUREG-1032 data for LOOP frequency and offsite power recovery but SPAR baseline EDG performance. Including all three types of NUREG-1032 inputs, the SBO CDF increases from 2.9E-6/rcry to 9.9E-6/rcry. However, if the SPAR baseline EDG performance is not changed, the increase is from 2.9E-6/rcry to 3.0E-6/rcry, which is negligible. Therefore, the improved EDG performance from the NUREG-1032 period to the present is the main reason for the drop in SBO CDF. (The historical reduction in LOOP frequency is countered by the historical increase in offsite power recovery times.) The other two sensitivity cases are similar but involve the use of NUREG/CR-5496 historical data (and associated EDG performance from NUREG/CR-5994). If all three types of inputs are modified, the SBO CDF increases from 2.9E-6/rcry to 8.3E-6/rcry. However, if the SPAR EDG performance is left unchanged, the increase is only to 3.7E-6/rcry. Again, the main driver in reducing the SBO CDF is the improved EDG performance. These four sensitivity case results are summarized in Figure 7-3.

Finally, a sensitivity case was run using plant-specific LOOP frequencies presented in Appendix D of the draft LOOP report. Plant-specific results are presented in Appendix E. Summary results are presented in Table 7-1. At the industry average level, the SBO CDF drops from 2.9E-6/rcry to 2.8E-6/rcry, which is negligible.

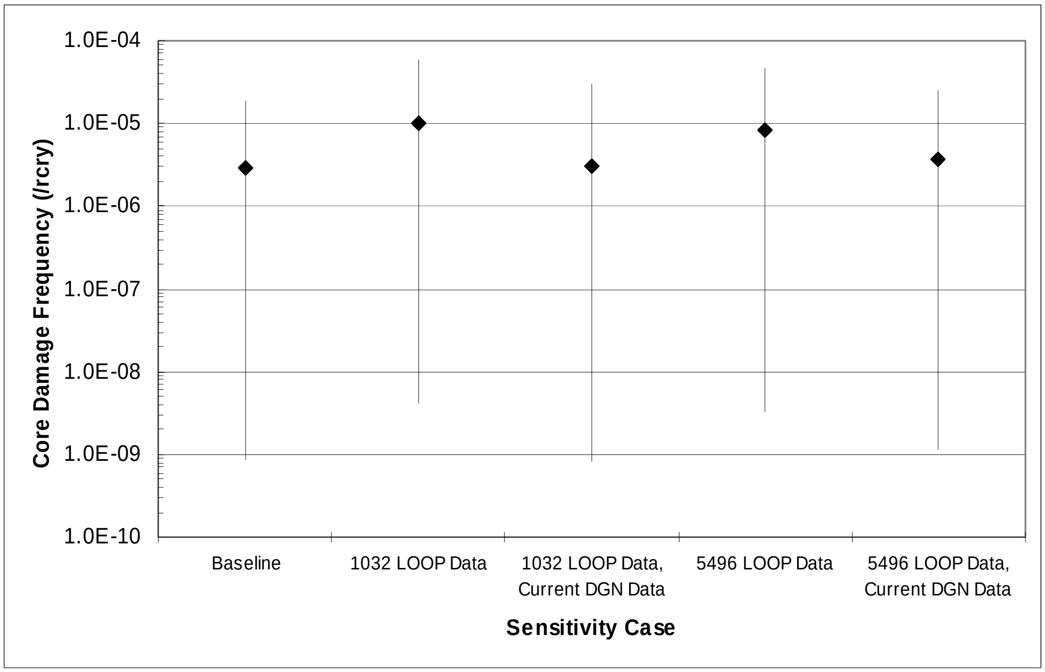


Figure 7-3. SBO CDF results for historical inputs sensitivity cases.

Sensitivity Analysis Results

8. SUMMARY AND CONCLUSIONS

The purpose of this study was to evaluate the current core damage risk from SBO scenarios at U.S. commercial nuclear power plants. Risk was to be evaluated for internal events during critical operation. To accomplish this, the following tasks were performed:

1. update LOOP and offsite power recovery data and models,

2. enhance the NRC-developed SPAR models covering all 103 U.S. commercial nuclear power plants (as part of the ongoing program to continually improve these models),

3. update EDG performance data,

4. update modeling and performance data for SBO coping features, and

5. quantify the SBO CDF for all 103 plants and summarize the results and sensitivities.

Each of these tasks was successfully completed.

The LOOP frequency and offsite power recovery efforts are documented in a separate report, the draft LOOP report. That effort generated up-to-date frequencies for five categories of LOOPs, along with associated nonrestoration (of offsite power) curves versus time. Results indicated that LOOP frequencies have historically trended downward, but the durations of such events increased during the late 1980s and early 1990s and have since been reasonably constant.

To specifically support the SBO effort, SPAR models were enhanced in the following areas: LOOP frequency and offsite power restoration, RCP seal leakage modeling, basic event data, and CCF data. These enhancements have resulted in SPAR models that are considered up to date in essentially all areas affecting LOOP and SBO predictions of CDF.

To support the development of estimates of current EDG performance, new EDG failure probabilities and rates were developed for FTS, FTLR, FTR, and TM. The FTS, FTLR, and FTR values were derived from EPIX data for the period 1998 – 2002. Results were compared with EDG unplanned demand (undervoltage events requiring the EDGs to start, load and run) information from LERs over the period 1997 – 2003. Although the unplanned demand data were shown statistically to not be significantly different from the EPIX data, several issues were identified that merit continued collection and review of such data. EDG TM data were obtained from the ROP SSU for the period 1998 – 2002 (planned and unplanned outages only). That result was also compared with unplanned demand data and found to not be significantly different. Finally, a comparison of current EDG UR with previous estimates indicates a historical trend downward.

SBO coping features were defined in this study to include all components, phenomena, and recoveries modeled in the SPAR SBO event trees. For components modeled in these event trees, such as TDPs, HPCS MDPs supported by EDGs, and DDPs, updated performance data were collected and evaluated, similar to what was done for the EDGs. In all cases, the historical URs of these components have trended downward.

Finally, the resulting SPAR models were quantified to obtain total CDF, total LOOP CDF, LOOP (non SBO) CDF, and SBO CDF. In addition, the EPS failure probabilities were quantified, such that the SBO coping failure probabilities could be determined. Results indicate an industry average SBO CDF (point estimate) of 2.9E-6/rcry. Results were compared with historical estimates of SBO CDF, ranging from approximately 1980 to the present. Again, these historical estimates trend downward. The historical drop in SBO CDF is probably the result of many changes – plant modifications made in response to the SBO rule, improvements in plant risk modeling, and improved component performance. However, the major contributor for this historical drop appears to be improved EDG performance.

Various sensitivity studies were also performed. As expected, the SBO CDF is sensitive to EDG performance. In addition, the draft LOOP report identified a significantly higher LOOP frequency during the summer (May through September). Because of this difference, the potential effects from allowing 14-day outages for EDGs (assumed to occur approximately once every 36 months) is highly dependent upon when such outages occur. If such outages were to occur only during the summer months, the increase in SBO CDF could be significant. However, if such outages were limited to the non-summer months, then the increase in SBO CDF is negligible.

Results of the study indicate several areas where continued monitoring of industry performance is recommended. First, the draft LOOP report indicated that the current LOOP frequency is dominated by the estimate for grid-related LOOPs. The grid-related LOOP frequency is heavily influenced by the August 14, 2003 widespread grid blackout that affected nine plants. Whether such events occur in the future (and if so, at what frequency) might affect the current LOOP frequency. In addition, the comparison of EDG unplanned demand data with EPIX data (used to develop the SPAR EDG failure probabilities and rates) indicated that FTLR failures (mostly recoverable) from the unplanned demands were different from FTLR failures from EPIX. In addition, the unplanned demand data for FTR were almost significantly different. The EDG unplanned demand data collection should continue to monitor these issues. Finally, the EDG TM (UA) probability used in SPAR is based on ROP SSU data. However, those data do not include overhaul maintenance outages. A limited comparison of the ROP SSU data with data from the MSPI pilot plants (which did include such outages) indicated only an 18% to 24% increase in the TM probability from such outages. When MSPI UA data begin to be reported, the EDG (and other component) TM estimates should be reviewed.

Overall, the study was successful in evaluating SBO CDF risk for U.S. commercial nuclear power plants. A strength of the study was the use of updated SPAR models to cover all 103 plants. In addition, EDG performance was investigated in detail.

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Appendix A

Emergency Diesel Generator Unplanned Demand Data

1997 – 2003

APPENDIX A

Emergency Diesel Generator Unplanned Demand Data

1997 – 2003

A.1 INTRODUCTION

Emergency diesel generator (EDG) unplanned demands involving bus undervoltage were identified from licensee event reports (LERs) and other sources for the period 1997 – 2003 for U.S. commercial nuclear power plants. Those events are listed in this appendix. Two tables are presented, each representing a different breakdown of the information. Those tables are summarized below:

Table A-1	Listing of all EDG unplanned demand events for 1997 – 2003, sorted by date.
Table A-2	Summary of the demands and failures.

A.2 EXPLANATION OF COLUMN HEADINGS

LER Number – The LER number describing the EDG event. If the number ends in “000”, there is no LER.

Event Date – The date of the EDG demand and/or failure event.

Plant Name – The name of the plant experiencing the EDG event.

Plant Status – Critical events are considered to be demands that occurred during critical operation, while Shutdown events are considered to be demands that occurred during shutdown operation.

Demands – The number of EDGs demanded at that time.

Run Time – The time in minutes that each demanded EDG ran. The total run time is the product of the demands and the run time.

Run Time Certainty – The degree of information that was available in the LER to accurately determine the run time. “C” if the analyst was certain, “U” if the analyst was uncertain. In general, if the run time was uncertain and no other information was available, 30 minutes was assumed.

Run Time (>60 minutes) – The number of run time minutes greater than 60 minutes. This is the run time used for the “FTR” failure mode.

EDG FTS – The number of observed FTS failures of the EDG.

EDG FTLR – The number of observed FTLR failures of the EDG.

EDG FTR – The number of observed FTR failures of the EDG.

EDG MOOS – The number of observed MOOS failures of the EDG.

LOOP ? – Did a LOOP cause the demand.

Comments – Explanatory notes about the event.

A.3 DATA TABLES

Table A-1. EDG unplanned demands and failures.

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
2961997001	05-Mar-97	Browns Ferry 3	Shutdown	1	58	C	0					Yes	No information on recovery of MOOS (not needed).
2961997001	05-Mar-97	Browns Ferry 3	Shutdown	1	58	C	0					Yes	
2961997001	05-Mar-97	Browns Ferry 3	Shutdown	1	58	C	0					Yes	
2961997001	05-Mar-97	Browns Ferry 3	Shutdown	1	0	C	0				1	Yes	
2931997004	07-Mar-97	Pilgrin	Shutdown	1	752	C	692					No	No information on recovery of MOOS (not needed).
2931997004	07-Mar-97	Pilgrin	Shutdown	1	0	C	0				1	No	
2951997007	11-Mar-97	Zion 1	Shutdown	1	3821	U	3761					Yes	
2951997007	11-Mar-97	Zion 1	Shutdown	1	3821	U	3761					Yes	
2951997007	11-Mar-97	Zion 1	Shutdown	1	3821	U	3761					Yes	
3271997007	04-Apr-97	Sequoyah 2	Shutdown	1	346	C	286					No	
3271997007	04-Apr-97	Sequoyah 2	Shutdown	1	686	C	626					No	
4581997001	06-May-97	River Bend	Critical	1	185	C	125					No	
3821997024	28-May-97	Waterford 3	Shutdown	1	2308	C	2248					No	
3251997006	08-Jun-97	Brunswick 1	Critical	1	272	C	212			1		No	Demand occurred due to testing. FTR repair required 497 min. No urgency to repair more quickly.
2861997008	16-Jun-97	Indian Point 3	Shutdown	1	204	C	144					Yes	FTLR could have been recovered manually. No information on recovery of MOOS (not needed).
2861997008	16-Jun-97	Indian Point 3	Shutdown	1	0	C	0		1			Yes	
2861997008	16-Jun-97	Indian Point 3	Shutdown	1	0	C	0				1	Yes	
2861997009	18-Jun-97	Indian Point 3	Shutdown	1	47	C	0					No	
2891997007	21-Jun-97	Three Mile Island 1	Critical	1	152	C	92					Yes	
2891997007	21-Jun-97	Three Mile Island 1	Critical	1	196	C	136					Yes	
2441997002	20-Jul-97	Ginna	Critical	1	41	C	0					No	
3821997028	20-Jul-97	Waterford 3	Shutdown	1	47	C	0					No	
2191997010	01-Aug-97	Oyster Creek	Critical	1	40	U	0					Yes	
2191997010	01-Aug-97	Oyster Creek	Critical	1	40	U	0					Yes	
5291997003	07-Sep-97	Palo Verde 2	Shutdown	1	21	C	0					No	Demand occurred due to testing

Table A-1. EDG unplanned demands and failures. (continued)

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
2661998002	08-Jan-98	Point Beach 1	Critical	1	557	C	497					Yes	The LOOP was a LOOP-NT.
2661998002	08-Jan-98	Point Beach 1	Critical	1	342	C	282					Yes	
4101998006	28-Mar-98	Nine Mile Point 2	Critical	1	195	C	135					No	
4101998006	28-Mar-98	Nine Mile Point 2	Critical	1	195	C	135					No	
2851998005	20-May-98	Fort Calhoun	Shutdown	1	109	C	49					Yes	
2851998005	20-May-98	Fort Calhoun	Shutdown	1	109	C	49					Yes	
2861998003	28-May-98	Indian Point 2	Critical	1	44	C	0					No	EDG was heating up because ventilation was not working, but this could have been recovered easily (breaker reset).
2711998016	09-Jun-98	Vermont Yankee	Critical	1	30	U	0					No	
3111998011	03-Aug-98	Salem 2	Shutdown	1	0	C	0				1	No	No information on recovery of MOOS (not needed).
4541998017	04-Aug-98	Byron 1	Critical	1	554	C	494					Yes	
4541998017	04-Aug-98	Byron 1	Critical	1	554	C	494					Yes	
3151998040	31-Aug-98	Cool 1	Shutdown	1	190	U	130					No	
3151998040	31-Aug-98	Cook 2	Shutdown	1	190	U	130					No	
2471998013	01-Sep-98	Indian Point 2	Shutdown	1	67	C	7					Yes	
2471998013	01-Sep-98	Indian Point 2	Shutdown	1	67	C	7					Yes	
2471998013	01-Sep-98	Indian Point 2	Shutdown	1	67	C	7					Yes	
4561998003	06-Sep-98	Braidwood 1	Shutdown	1	528	C	468					Yes	
4561998003	06-Sep-98	Braidwood 1	Shutdown	1	528	C	468					Yes	
4141998004	06-Sep-98	Catawba 2	Shutdown	1	0	C	0				1	No	Demand occurred due to tagout. No information on recovery of MOOS (not needed).
4611998036	18-Oct-98	Clinton 1	Shutdown	1	184	C	124					No	
2191998016	28-Oct-98	Oyster Creek 1	Shutdown	1	30	U	0					No	
2961998007	16-Nov-98	Browns Ferry 3	Critical	1	70	U	10					No	
2961998007	16-Nov-98	Browns Ferry 3	Critical	1	70	U	10					No	
2441998005	20-Nov-98	Ginna	Critical	1	15	C	0					No	
2551998013	22-Dec-98	Palisades	Shutdown	1	30	U	0					Yes	

Table A-1. EDG unplanned demands and failures. (continued)

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
2551998013	22-Dec-98	Palisades	Shutdown	1	30	U	0					Yes	
4611999002	06-Jan-99	Clinton 1	Shutdown	1	492	C	432					Yes	
4611999002	06-Jan-99	Clinton 1	Shutdown	1	531	C	471					Yes	
4611999002	06-Jan-99	Clinton 1	Shutdown	1	587	C	527					Yes	
2751999001	03-Mar-99	Diablo Canyon 1	Shutdown	1	48	C	0					No	
4991999003	12-Mar-99	South Texas 2	Critical	1	101	U	41					No	For the FTLR, manual actions closed the breaker and then the EDG loaded successfully.
4991999003	12-Mar-99	South Texas 2	Critical	1	101	U	41		1			No	
4121999005	29-Mar-99	Beaver Valley 2	Shutdown	1	30	U	0					No	
4821999005	12-May-99	Wolf Creek	Critical	1	30	U	0					No	
4101999010	24-Jun-99	Nine Mile Point 2	Critical	1	30	U	0					No	
4101999010	24-Jun-99	Nine Mile Point 2	Critical	1	30	U	0					No	
2891999009	26-Jun-99	Threee Mile Island 1	Critical	1	192	C	132					No	
4991999005	24-Aug-99	South Texas 2	Critical	1	217	C	157					No	
2471999015	31-Aug-99	Indian Point 2	Critical	1	779	C	719					Yes	FTLR (output circuit breaker opened 14 sec after closing) could have been recovered.
2471999015	31-Aug-99	Indian Point 2	Critical	1	779	C	719					Yes	
2471999015	31-Aug-99	Indian Point 2	Critical	1	0	C	0		1			Yes	
3271999002	16-Sep-99	Sequoyah 1	Critical	1	464	C	404					No	
2611999001	27-Sep-99	Robinson	Shutdown	1	154	C	94					No	
2801999007	09-Oct-99	Surry 1	Critical	1	2849	C	2789					No	
2801999007	09-Oct-99	Surry 2	Critical	1	2907	C	2847					No	
2851999004	26-Oct-99	Fort Calhoun	Shutdown	1	34	C	0					Yes	LOOP signal while shutdown. Both EDGs were initially switched to "Off-Auto". Operators changed switch to "Auto" and then both EDGs started and loaded.
2851999004	26-Oct-99	Fort Calhoun	Shutdown	1	34	C	0					Yes	
3151999028	16-Dec-99	Cook 1	Shutdown	1	232	C	172					No	
2892000001	10-Jan-00	Three Mile Island 1	Critical	1	697	C	637					No	

Table A-1. EDG unplanned demands and failures. (continued)

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
2192000003	01-Mar-00	Oyster Creek 1	Critical	1	153	C	93					No	
3252000001	03-Mar-00	Brunswick 1	Shutdown	1	524	C	464					Yes	FTR after approximately 149 min. Cause was a fire. Not quickly recoverable. EDG returned to service 5 days later.
3252000001	03-Mar-00	Brunswick 1	Shutdown	1	149	C	89			1		Yes	
3382000002	04-Apr-00	North Anna 1	Shutdown	1	0	C	0	1				No	EDG cylinder was filled with oil, from previous maintenance activities. No urgency to recover. EDG returned to service the next day.
3382000002	04-Apr-00	North Anna 2	Critical	1	115	U	0					No	
3482000005	09-Apr-00	Farley 1	Shutdown	1	55	C	0					Yes	Train A EDG started and loaded. Apparently the swing EDG also started and loaded. Train B EDG was in MOOS. No information on recovery of MOOS (not needed).
3482000005	09-Apr-00	Farley 1	Shutdown	1	55	C	0					Yes	
3482000005	09-Apr-00	Farley 1	Shutdown	1	0	C	0				1	Yes	
3462000004	22-Apr-00	Davis-Besse	Shutdown	1	42	U	0					Yes	EDG loaded run time is somewhere between 10 and 74 min. 42 is average of these two values.
3462000004	22-Apr-00	Davis-Besse	Shutdown	1	42	U	0					Yes	
2752000004	15-May-00	Diablo Canyon 1	Critical	1	2014	C	1954					Yes	
2752000004	15-May-00	Diablo Canyon 1	Critical	1	2014	C	1954					Yes	
2752000004	15-May-00	Diablo Canyon 1	Critical	1	2014	C	1954					Yes	
3162000004	08-Jun-00	Cook 1	Shutdown	1	123	C	63					No	
3162000004	08-Jun-00	Cook 2	Shutdown	1	169	C	109					No	
2512000004	21-Oct-00	Turkey Point 4	Shutdown	1	125	U	65					Yes	EDG loaded run time is somewhere between 111 and 140 min. 125 is average of these two values.
2512000004	21-Oct-00	Turkey Point 4	Shutdown	1	125	U	65					Yes	
3012000005	10-Nov-00	Point Beach 2	Shutdown	1	114	C	54					No	
4992001001	07-Feb-01	South Texas 2	Critical	1	30	U	0					No	
2472001002	14-Feb-01	Indian Point 2	Critical	1	29	C	0					No	

Table A-1. EDG unplanned demands and failures. (continued)

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
4432001002	05-Mar-01	Seabrook	Critical	1	2122	C	2062					Yes	
4432001002	05-Mar-01	Seabrook	Critical	1	2122	C	2062					Yes	
3232001002	20-May-01	Diablo Canyon	Shutdown	1	30	U	0					No	Demand occurred due to testing. EDG initially in test configuration. Operators switched EDG to auto and it started and loaded.
2652001001	02-Aug-01	Quad Cities 2	Critical	1	154	C	94					Yes	
2652001001	02-Aug-01	Quad Cities 2	Critical	1	154	C	94					Yes	
3742001003	03-Sep-01	LaSalle 2	Critical	1	30	U	0		1			No	EDG connected to bus, but bus loads were not reconnected (fuse failures). No urgency to recover this, so recovery was not attempted during the incident.
4582001004	17-Oct-01	River Bend	Critical	1	1083	U	1023					No	EDG loaded run time is somewhere between 1005 and 1162 min. 1083 is average of these two values.
4142001003	07-Dec-01	Catawba 2	Critical	1	182	C	122					No	
2472001007	26-Dec-01	Indian Point 2	Shutdown	1	30	U	0					No	
2962002002	26-Mar-02	Browns Ferry 3	Shutdown	1	1393	U	1333					No	EDG loaded run time is somewhere between 1350 and 1437 (1479). 1393 (1414) is average of these two values.
2962002002	26-Mar-02	Browns Ferry 3	Shutdown	1	1414	U	1354					No	
3022002001	17-Jun-02	Crystal River 3	Critical	1	617	C	557					No	
3022002001	20-Jun-02	Crystal River 3	Critical	1	287	C	227					No	
4162002003	22-Jun-02	Grand Gulf	Critical	1	30	U	0					No	
3272002004	12-Jul-02	Sequoyah 1	Critical	1	92	C	32					No	Other EDG also started but was not needed. That EDG was later stopped because of an alarm indication.
2472002003	19-Jul-02	Indian Point 2	Critical	1	461	U	401					No	MOOS recovered in 15

Table A-1. EDG unplanned demands and failures. (continued)

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
2472002003	19-Jul-02	Indian Point 2	Critical	1	461	U	401				1	No	minutes and EDG started and loaded. Other EDG not loaded until MOOS was recovered.
4822002005	09-Sep-02	Wolf Creek	Critical	1	30	U	0					No	
3902002004	21-Sep-02	Watts Bar 1	Critical	1	250	C	190					No	
3902002004	21-Sep-02	Watts Bar 1	Critical	1	250	C	190					No	
3902002005	27-Sep-02	Watts Bar 1	Critical	1	982	C	922					Yes	The LOOP was a LOOP-NT.
3902002005	27-Sep-02	Watts Bar 1	Critical	1	1035	C	975					Yes	
3902002005	27-Sep-02	Watts Bar 1	Critical	1	1048	C	988					Yes	
3902002005	27-Sep-02	Watts Bar 1	Critical	1	1084	C	1024					Yes	
3692002002	01-Oct-02	McGuired 1	Shutdown	1	30	U	0					No	Demand occurred due to testing.
2542002002	13-Nov-02	Quad Cities 1	Shutdown	1	30	U	0					No	
4982003001	19-Jan-03	South Texas 1	Critical	1	50	C	0		1			No	Sequencer failed. Recovered by adding loads manually.
4982003001	19-Jan-03	South Texas 1	Critical	1	71	C	11					No	
4982003001	19-Jan-03	South Texas 2	Shutdown	1	345	U	285					No	
3352003002	17-Feb-03	St. Lucie 1	Critical	1	30	U	0					No	
3342003003	27-Feb-03	Beaver Valley 1	Critical	1	752	C	692					No	
2552003003	25-Mar-03	Palisades	Shutdown	1	3261	C	3201					Yes	
2552003003	25-Mar-03	Palisades	Shutdown	1	3261	C	3201					Yes	
4162003002	24-Apr-03	Grand Gulf	Critical	1	30	U	0					Yes	
4162003002	24-Apr-03	Grand Gulf	Critical	1	30	U	0					Yes	
2722003002	29-Jul-03	Salem 1	Critical	1	512	C	452					Yes	
2722003002	29-Jul-03	Salem 1	Critical	1	512	C	452					Yes	
2722003002	29-Jul-03	Salem 1	Critical	1	512	C	452					Yes	
2472003004	03-Aug-03	Indian Point 2	Critical	1	37	U	0					No	
2202003002	14-Aug-03	Nine Mile Point 1	Critical	1	448	C	388					Yes	
2202003002	14-Aug-03	Nine Mile Point 1	Critical	1	487	C	427					Yes	
2862003005	14-Aug-03	Indian Point 3	Critical	1	599	C	539					Yes	
2862003005	14-Aug-03	Indian Point 3	Critical	1	599	C	539					Yes	
2862003005	14-Aug-03	Indian Point 3	Critical	1	599	C	539					Yes	

Table A-1. EDG unplanned demands and failures. (continued)

LER Number	Event Date	Plant Name	Plant Status	Demands	Run Time (min.)	Run Time Cer-tainty	Run Time (>60 min)	EDG FTS	EDG FTLR	EDG FTR	EDG MOOS	LOOP ?	Comments
2472003005	14-Aug-03	Indian Point 2	Critical	1	599	C	539					Yes	
2472003005	14-Aug-03	Indian Point 2	Critical	1	599	C	539					Yes	
2472003005	14-Aug-03	Indian Point 2	Critical	1	599	C	539					Yes	
3412003002	14-Aug-03	Fermi 2	Critical	1	1281	C	1221					Yes	
3412003002	14-Aug-03	Fermi 2	Critical	1	1281	C	1221					Yes	
3412003002	14-Aug-03	Fermi 2	Critical	1	1281	C	1221					Yes	
3412003002	14-Aug-03	Fermi 2	Critical	1	1281	C	1221					Yes	
3462003009	14-Aug-03	Davis-Besse	Shutdown	1	848	C	788					Yes	
3462003009	14-Aug-03	Davis-Besse	Shutdown	1	1337	C	1277					Yes	
3332003001	14-Aug-03	Fitzpatrick	Critical	1	435	C	375					Yes	
3332003001	14-Aug-03	Fitzpatrick	Critical	1	414	C	354					Yes	
4102003002	14-Aug-03	Nine Mile Point 2	Critical	1	900	C	840					Yes	
4102003002	14-Aug-03	Nine Mile Point 2	Critical	1	565	C	505					Yes	
4102003002	14-Aug-03	Nine Mile Point 2	Critical	1	709	C	649					Yes	
4402003002	14-Aug-03	Perry	Critical	1	1662	C	1602					Yes	
4402003002	14-Aug-03	Perry	Critical	1	1662	C	1602					Yes	
2772003004	15-Sep-03	Peach Botton 2	Critical	1	408	C	348					Yes	The FTR occurred after 63 min (low jacket coolant pressure). Recovery not attempted.
2772003004	15-Sep-03	Peach Botton 2	Critical	1	63	C	3			1		Yes	
2772003004	15-Sep-03	Peach Botton 2	Critical	1	408	C	348					Yes	
2772003004	15-Sep-03	Peach Botton 2	Critical	1	408	C	348					Yes	
3542003007	19-Sep-03	Hope Creek	Critical	1	30	U	0					No	
3542003007	19-Sep-03	Hope Creek	Critical	1	30	U	0					No	
2442003005	15-Oct-03	Ginna	Shutdown	1	55	C	0					No	
2442003005	13-Nov-03	Ginna	Critical	1	22	C	0					No	
2202003003	13-Nov-03	Nine Mile Point 1	Critical	1	30	U	0					No	

Table A-2. DGN demand and failure data summary.

	Critical D	All D	All T (min)	T > 1h (min)	FTS	FTLR	FTR	Critical MOOS	Shutdown MOOS	Summary of Failures
1997	7	25	16974	15844	0	1	1	0	3	1 FTLR (recoverable), 1 FTR, 3 TM (during shutdown)
1998	11	26	4755	3496	0	0	0	0	2	2 TM (during shutdown)
1999	13	22	10621	9545	0	2	0	0	0	1 FTLR, 1 FTLR (recovered)
2000	6	19	8530	7501	1	0	1	0	1	1 FTS, 1 FTR
2001	9	11	5966	5457	0	1	0	0	0	1 FTLR (recoverable)
2002	13	17	9494	8594	0	0	0	1	0	1 TM (recoverable, during critical operation)
2003	37	43	29042	26718	0	1	1	0	0	1 FTLR (recoverable), 1 FTR
Totals 1997 - 2003	96	163	85382	77155	1	5	3	1	6	1 FTS, 5 FTLR (4 recovered or recoverable), 3 FTR, and 7 MOOS (1 during critical operation and recovered, 6 during shutdown with no attempt to recover)
Not recovered					1	1	3	0	?	1 FTS, 1 FTLR, 3 FTR

Appendix B

Plant-Specific Emergency Power System Results

APPENDIX B

Plant-Specific Emergency Power System Results

The emergency power system (EPS) fault tree for each plant has been calculated using the SPAR models. This appendix presents the results of those calculations. The EPS system fault tree for each plant was evaluated using the baseline component failure data (which includes a 24-hour mission time for the EDG component). The results of the uncertainty calculations are shown in Table B-1.

Table B-1. EPS system uncertainty values.

Plant	5%	Median	Mean	95%
Arkansas 1	3.62E-05	2.06E-04	4.10E-04	1.46E-03
Arkansas 2	1.39E-04	1.18E-03	2.43E-03	8.72E-03
Beaver Valley 1	9.54E-06	8.80E-05	3.01E-04	1.32E-03
Beaver Valley 2	1.04E-05	1.10E-04	3.78E-04	1.56E-03
Braidwood 1	4.97E-05	2.75E-04	5.63E-04	1.82E-03
Braidwood 2	4.97E-05	2.75E-04	5.63E-04	1.82E-03
Browns Ferry 2	1.51E-06	1.88E-05	6.64E-05	2.71E-04
Browns Ferry 3	1.64E-06	1.96E-05	6.52E-05	2.51E-04
Brunswick 1	2.48E-04	1.43E-03	2.57E-03	8.88E-03
Brunswick 2	2.48E-04	1.43E-03	2.57E-03	8.88E-03
Byron 1	4.97E-05	2.75E-04	5.63E-04	1.82E-03
Byron 2	4.97E-05	2.75E-04	5.63E-04	1.82E-03
Callaway	5.24E-04	3.20E-03	5.49E-03	1.95E-02
Calvert Cliffs 1	4.73E-05	2.65E-04	4.88E-04	1.66E-03
Calvert Cliffs 2	4.73E-05	2.65E-04	4.88E-04	1.66E-03
Catawba 1	5.52E-06	2.58E-04	7.41E-04	2.80E-03
Catawba 2	5.52E-06	2.58E-04	7.41E-04	2.80E-03
Clinton 1	5.69E-04	3.48E-03	5.83E-03	1.87E-02
Columbia 2	5.05E-04	2.96E-03	5.46E-03	1.76E-02
Comanche Peak 1	4.56E-04	2.84E-03	5.37E-03	1.85E-02
Comanche Peak 2	4.56E-04	2.84E-03	5.37E-03	1.85E-02
Cook 1	2.00E-04	1.37E-03	2.47E-03	7.83E-03
Cook 2	2.00E-04	1.37E-03	2.47E-03	7.83E-03
Cooper	2.55E-04	1.49E-03	2.55E-03	8.34E-03
Crystal River 3	2.48E-04	1.64E-03	2.75E-03	9.06E-03
Davis-Besse	3.49E-04	2.01E-03	3.37E-03	1.09E-02
Diablo Canyon 1	3.12E-05	1.69E-04	3.13E-04	1.03E-03
Diablo Canyon 2	3.12E-05	1.69E-04	3.13E-04	1.03E-03
Dresden 2	1.55E-07	7.12E-06	4.83E-05	1.95E-04
Dresden 3	1.55E-07	7.12E-06	4.83E-05	1.95E-04
Duane Arnold	9.39E-04	4.13E-03	6.53E-03	2.03E-02
Farley 1	8.83E-06	1.54E-04	4.75E-04	2.14E-03
Farley 2	8.83E-06	1.54E-04	4.75E-04	2.14E-03
Fermi 2	2.69E-07	1.02E-05	5.07E-05	1.71E-04
FitzPatrick	1.85E-05	1.05E-04	1.98E-04	5.90E-04
Fort Calhoun	2.06E-04	1.37E-03	2.43E-03	7.94E-03
Ginna	2.07E-04	1.32E-03	2.41E-03	7.67E-03
Grand Gulf	5.68E-04	3.83E-03	6.42E-03	1.99E-02
Harris	5.58E-04	3.21E-03	5.62E-03	1.88E-02
Hatch 1	3.59E-05	1.86E-04	3.95E-04	1.43E-03
Hatch 2	3.59E-05	1.86E-04	3.95E-04	1.43E-03

Plant	5%	Median	Mean	95%
Hope Creek	6.95E-05	4.13E-04	1.05E-03	3.96E-03
Indian Point 2	4.75E-05	2.30E-04	4.09E-04	1.40E-03
Indian Point 3	6.67E-05	2.86E-04	4.57E-04	1.34E-03
Kewaunee	2.76E-04	1.48E-03	2.56E-03	8.33E-03
La Salle 1	1.81E-05	1.59E-04	4.94E-04	2.18E-03
La Salle 2	1.81E-05	1.59E-04	4.94E-04	2.18E-03
Limerick 1	1.90E-05	1.09E-04	2.37E-04	7.64E-04
Limerick 2	1.90E-05	1.09E-04	2.37E-04	7.64E-04
McGuire 1	5.66E-06	3.19E-04	7.84E-04	3.12E-03
McGuire 2	5.66E-06	3.19E-04	7.84E-04	3.12E-03
Millstone 2	3.52E-05	2.02E-04	3.96E-04	1.27E-03
Millstone 3	3.21E-05	1.88E-04	3.78E-04	1.30E-03
Monticello	3.35E-04	1.59E-03	2.65E-03	8.15E-03
Nine Mile Pt. 1	3.90E-04	1.92E-03	3.16E-03	9.32E-03
Nine Mile Pt. 2	2.20E-04	1.36E-03	2.40E-03	8.54E-03
North Anna 1	6.11E-06	4.60E-05	1.20E-04	4.30E-04
North Anna 2	6.11E-06	4.60E-05	1.20E-04	4.30E-04
Oconee 1	2.66E-04	1.48E-03	2.04E-03	5.45E-03
Oconee 2	2.66E-04	1.48E-03	2.04E-03	5.45E-03
Oconee 3	2.66E-04	1.48E-03	2.04E-03	5.45E-03
Oyster Creek	2.28E-04	1.35E-03	2.40E-03	7.46E-03
Palisades	2.42E-04	1.42E-03	2.48E-03	7.88E-03
Palo Verde 1	1.95E-05	4.64E-04	1.10E-03	4.73E-03
Palo Verde 2	1.95E-05	4.64E-04	1.10E-03	4.73E-03
Palo Verde 3	1.95E-05	4.64E-04	1.10E-03	4.73E-03
Peach Bottom 2	7.66E-05	8.08E-04	1.36E-03	4.42E-03
Peach Bottom 3	7.66E-05	8.08E-04	1.36E-03	4.42E-03
Perry	4.65E-04	3.11E-03	5.45E-03	1.88E-02
Pilgrim	2.06E-04	1.37E-03	2.43E-03	7.94E-03
Point Beach 1	4.30E-07	1.25E-05	4.93E-05	1.93E-04
Point Beach 2	4.30E-07	1.25E-05	4.93E-05	1.93E-04
Prairie Island 1	1.41E-05	8.72E-05	1.34E-04	4.05E-04
Prairie Island 2	1.41E-05	8.72E-05	1.34E-04	4.05E-04
Quad Cities 1	1.67E-07	6.14E-06	5.04E-05	2.32E-04
Quad Cities 2	1.67E-07	6.14E-06	5.04E-05	2.32E-04
River Bend	5.40E-04	3.15E-03	5.17E-03	1.68E-02
Robinson 2	3.09E-04	1.59E-03	2.64E-03	8.70E-03
Salem 1	2.13E-05	3.45E-04	1.03E-03	4.23E-03
Salem 2	2.13E-05	3.45E-04	1.03E-03	4.23E-03
San Onofre 2	1.48E-05	1.63E-04	4.96E-04	2.10E-03
San Onofre 3	1.48E-05	1.63E-04	4.96E-04	2.10E-03
Seabrook	3.96E-04	2.04E-03	3.28E-03	1.04E-02
Sequoyah 1	5.35E-05	3.41E-04	6.96E-04	2.40E-03
Sequoyah 2	5.35E-05	3.41E-04	6.96E-04	2.40E-03
South Texas 1	3.94E-05	1.82E-04	3.44E-04	1.20E-03
South Texas 2	3.94E-05	1.82E-04	3.44E-04	1.20E-03
St. Lucie 1	1.82E-05	1.82E-04	4.94E-04	1.99E-03
St. Lucie 2	1.82E-05	1.82E-04	4.94E-04	1.99E-03
Summer	1.92E-04	1.34E-03	2.49E-03	8.26E-03
Surry 1	5.63E-06	9.95E-05	3.97E-04	1.58E-03
Surry 2	5.63E-06	9.95E-05	3.97E-04	1.58E-03
Susquehanna 1	4.44E-06	5.38E-05	1.40E-04	4.69E-04
Susquehanna 2	4.44E-06	5.38E-05	1.40E-04	4.69E-04
Three Mile Isl 1	2.33E-04	1.48E-03	2.58E-03	8.73E-03
Turkey Point 3	3.53E-05	2.14E-04	3.63E-04	1.14E-03

Plant	5%	Median	Mean	95%
Turkey Point 4	3.53E-05	2.14E-04	3.63E-04	1.14E-03
Vermont Yankee	2.26E-07	4.11E-06	1.09E-05	4.13E-05
Vogtle 1	4.85E-04	2.46E-03	3.53E-03	9.68E-03
Vogtle 2	4.85E-04	2.46E-03	3.53E-03	9.68E-03
Waterford 3	4.13E-04	1.93E-03	3.24E-03	1.04E-02
Watts Bar 1	1.83E-05	1.43E-04	4.21E-04	1.62E-03
Wolf Creek	4.93E-04	2.94E-03	5.47E-03	1.76E-02

B.1 EPS Class

The EPS at many plants is configured similarly. In order to summarize the results, a scheme to group the EPS for several plants together was developed. The EPS, as modeled in the SPAR models, consists of the emergency power supplies, support equipment, electrical components, and human actions.

The scheme, called EPS class, follows the number of redundant EDGs for class 1 to 4 and increases the redundancy as the class number increases. Class 5 EPS models make use of early alternate power sources such as GTGs, SBO EDGs, and HTGs. Table B-2 presents the basic description. Table B-3 lists the plants within each EPS class. Figure B-1 shows the range of EPS point estimate probabilities for each class.

Table B-2. EPS Class identification.

Class	Description
Class 1	Plant EPS system makes use of 2 EDG or HTG machines. No sources of alternate power are included in the models. No EDGs are provided by another plant either through cross-tie or swing. We include three plants with SBO EDGs that require human action to transfer the SBO to a bus. Because of high human error probabilities, the SBO EDG is essentially unavailable.
Class 2	Plant EPS system makes use of 3 EDG machines. No sources of alternate power are included in the models. Some have cross-tie and/or swing and some have 3 at the plant.
Class 3	Plant EPS system makes use of 4 EDG machines. No sources of alternate power are included in the models. The 4 EDG machines are either all at the plant or comprised of 2 at the plant and two at the second plant at the site.
Class 4	Plant EPS system makes use of 6 to 8 EDG machines. Two or 4 EDGs are cross-tied to the other plant. No sources of alternate power are included in the model.
Class 5	Plant EPS system makes use of 2 to 5 EDG machines. One or 2 GTGs, SBOs, HTGs, or other unit commercial cross-tie are used for alternate power. This broad category was selected so that the EPS systems with alternate power supplies could be grouped and to minimize the total number of groups.

Table B-3. Plant EPS Class listing.

Class 1	Class 2	Class 3	Class 4	Class 5
Arkansas 2	Diablo Canyon 1	Beaver Valley 1	Browns Ferry 2	Arkansas 1
Brunswick 1	Diablo Canyon 2	Beaver Valley 2	Browns Ferry 3	Calvert Cliffs 1
Brunswick 2	Farley 1	Braidwood 1	Limerick 1	Calvert Cliffs 2
Callaway	Farley 2	Braidwood 2	Limerick 2	Dresden 2
Clinton 1	Hatch 1	Byron 1		Dresden 3
Columbia 2	Hatch 2	Byron 2		Fermi 2
Comanche Peak 1	Indian Point 2	Catawba 1		McGuire 1
Comanche Peak 2	Indian Point 3	Catawba 2		McGuire 2
Cook 1	Peach Bottom 2	FitzPatrick		Millstone 2
Cook 2	Peach Bottom 3	Hope Creek		Millstone 3
Cooper	South Texas 1	La Salle 1		North Anna 1
Crystal River 3	South Texas 2	La Salle 2		North Anna 2
Davis-Besse		Prairie Island 1		Palo Verde 1
Duane Arnold		Prairie Island 2		Palo Verde 2
Fort Calhoun		San Onofre 2		Palo Verde 3
Ginna		San Onofre 3		Point Beach 1
Grand Gulf		Sequoyah 1		Point Beach 2
Harris		Sequoyah 2		Quad Cities 1
Kewaunee		St. Lucie 1		Quad Cities 2
Monticello		St. Lucie 2		Salem 1
Nine Mile Pt. 1		Turkey Point 3		Salem 2
Nine Mile Pt. 2		Turkey Point 4		Surry 1
Oconee 1		Watts Bar 1		Surry 2
Oconee 2				Susquehanna 1
Oconee 3				Susquehanna 2
Oyster Creek				Vermont Yankee
Palisades				
Perry				
Pilgrim				
River Bend				
Robinson 2				
Seabrook				
Summer				
Three Mile Isl 1				
Vogtle 1				
Vogtle 2				
Waterford 3				
Wolf Creek				

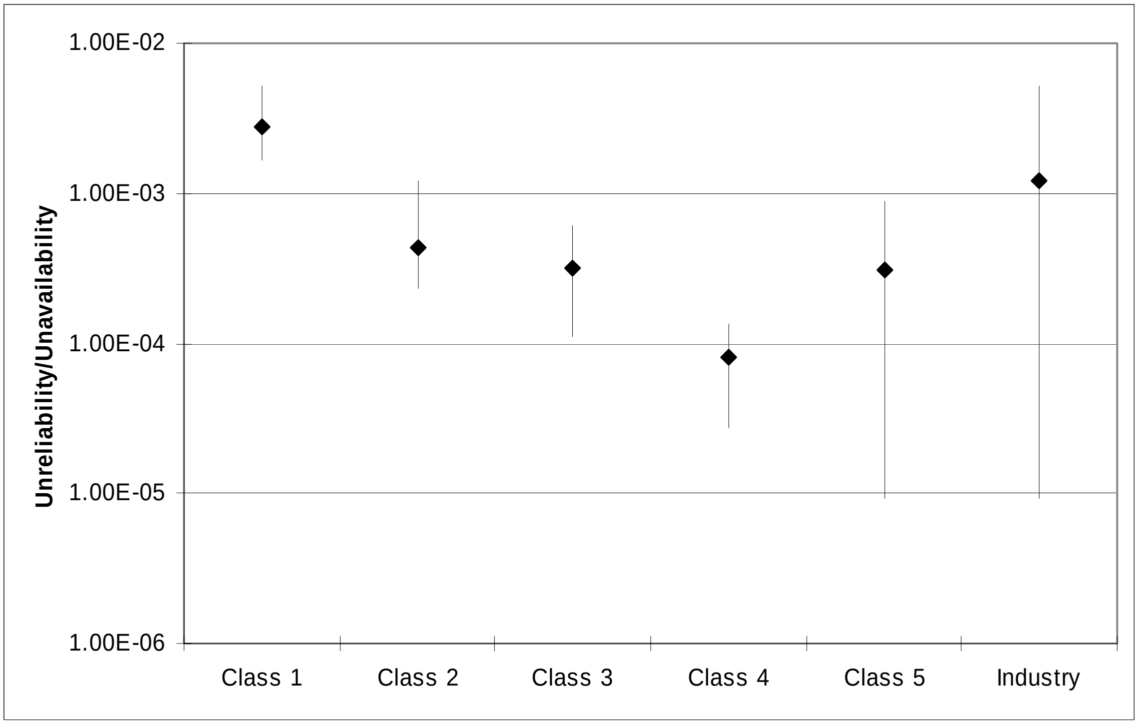

Figure B-1. EPS Class probability distributions.

Class 1 – The higher probability models include an event for the operator to establish EDG room cooling; this event is 1.0E-3 and drives the unreliability. The lower probability EPS models include the SBO EDG, but the operator action to provide power from the SBO EDG is so high that there is very little benefit from it.

Class 2 – The higher probability models include an event for the operator to establish EDG room cooling; this event is 1.0E-3 and drives the unreliability.

Class 3 – The higher probability models are those with higher importance for the service water cooling.

Class 4 – The number of EDGs has the greatest effect on the models in this class.

Class 5 – This class is a mixture of alternate power sources and numbers of emergency EDGs. More than one alternate source produces the lower result. The capability to align the emergency buses to alternate power supplies is tempered with the human action to accomplish this. The Vermont Yankee model takes advantage of the Vernon hydroelectric plant, which does not need to be started and only requires closing a cross-tie to power the vital buses.

B.2 Class Importance

The importance measures for each class were combined to show the importance of the major types of equipment modeled in the EPS system. The top importances are shown in Figure B-2 to Figure B-6.

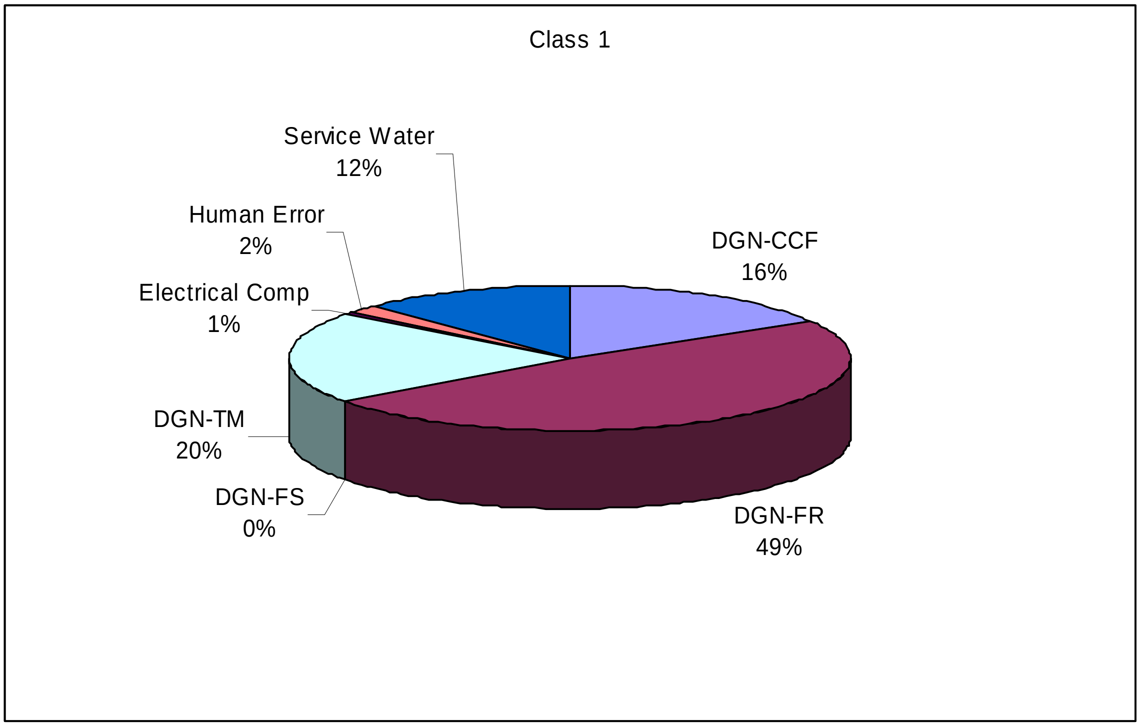

Figure B-2. Class 1 EPS component importance.

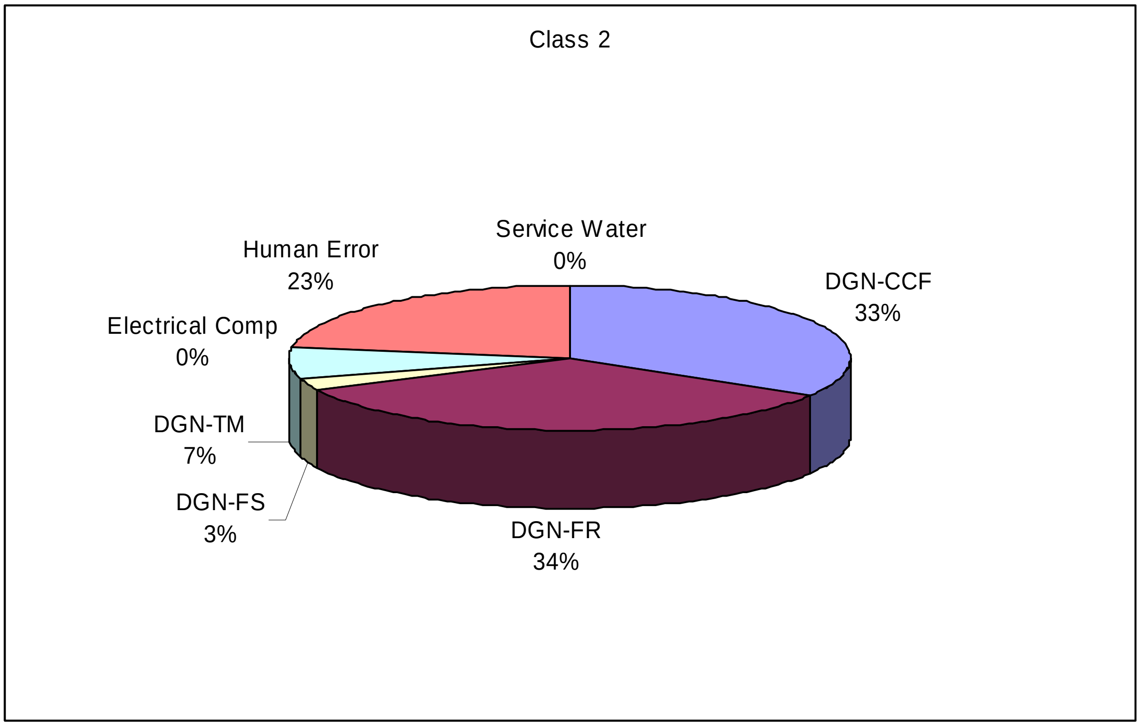

Figure B-3. Class 2 EPS component importance.

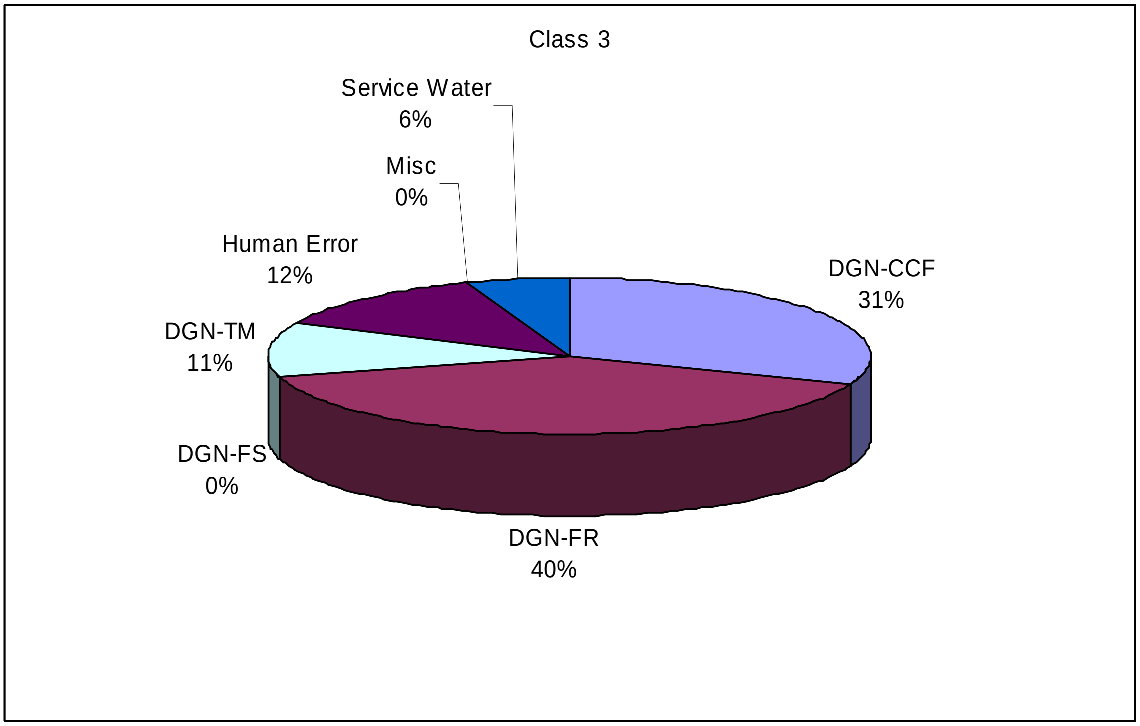

Figure B-4. Class 3 EPS component importance.

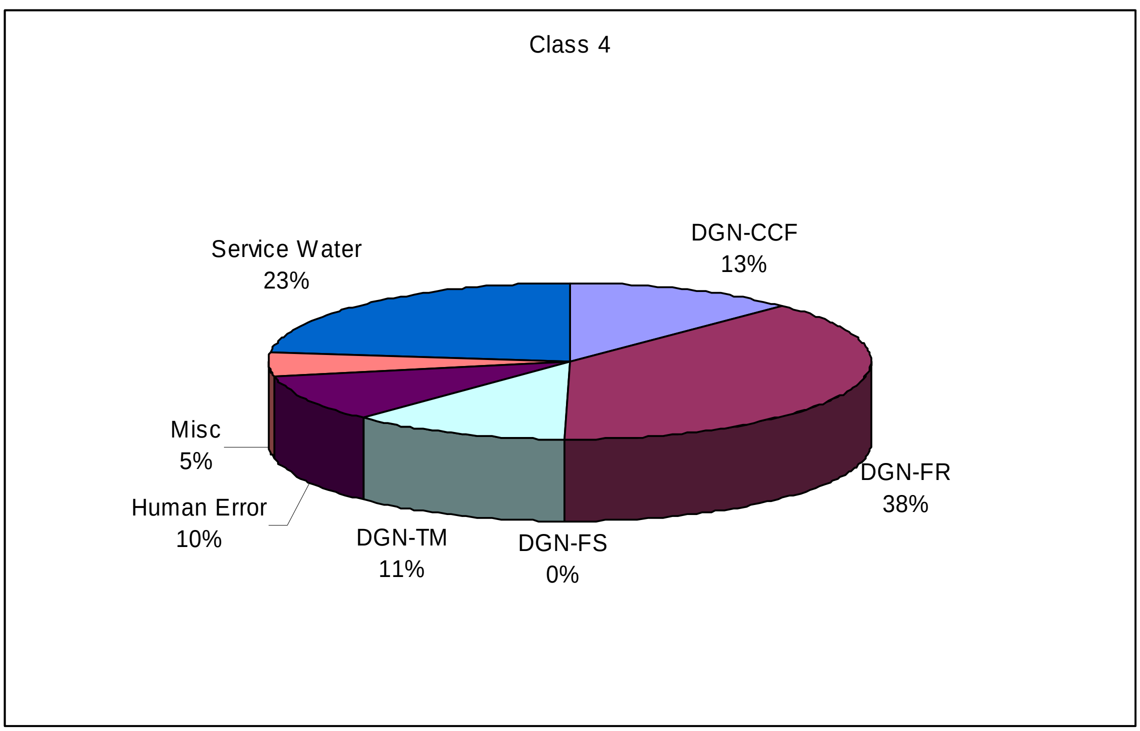

Figure B-5. Class 4 EPS component importance.

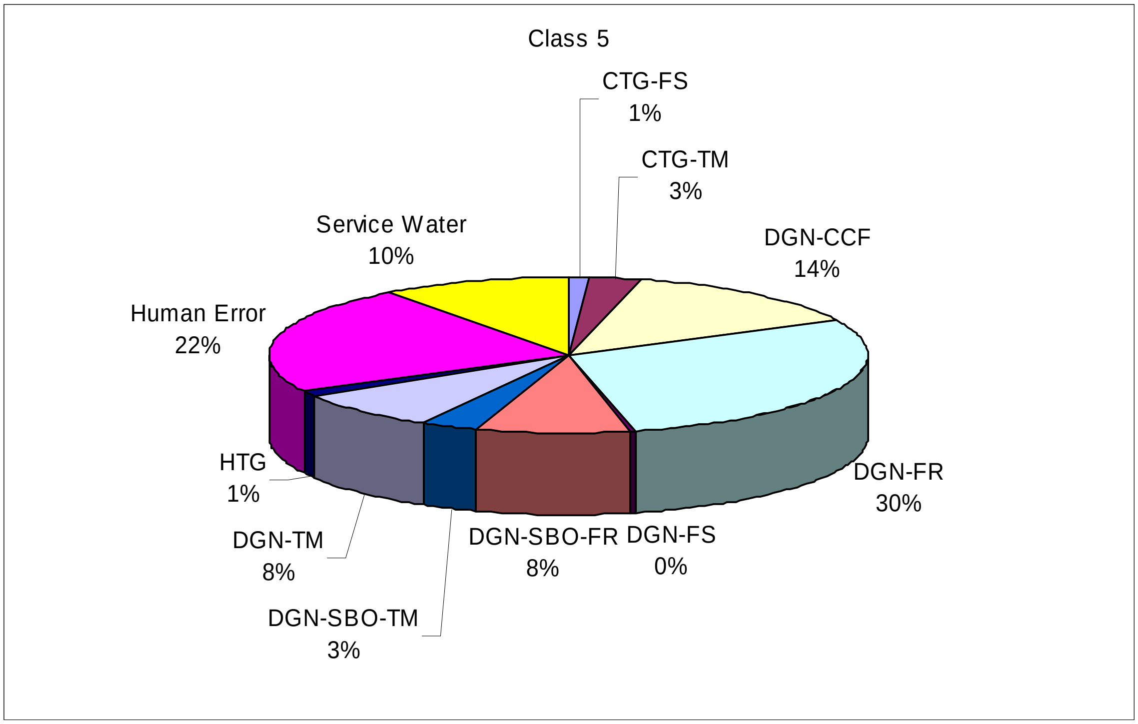

Figure B-6. Class 5 EPS component importance.

Appendix C

Plant-Specific Station Blackout Results

Using Industry Data

APPENDIX C

Plant-Specific Station Blackout Results Using Industry Data

The purpose of this appendix is to present the current core damage risk from SBO scenarios at U.S. commercial nuclear power plants based on the industry LOOP frequency (see Appendix D). Current is defined as a period centered about the year 2000. The industry average results of the SBO, LOOP, and total core damage frequencies (CDFs) are shown in Table C-1. All 103 operating commercial nuclear power plants are addressed. Risk is evaluated only for critical operation; risk from shutdown operation is not addressed in this report. Risk is defined as CDF. The standardized plant analysis risk (SPAR) models developed by the NRC for the 103 operating plants were used to evaluate plant-specific CDF risk.

Table C-1. Summary of plant-specific LOOP, SBO, and Total CDF results.

	Total CDF (1/rcry)	Total LOOP CDF (1/rcry)	LOOP Fract. CDF (1/rcry)	SBO Fract. CDF (1/rcry)	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability
Average	1.80E-05	3.41E-06	5.21E-07	2.89E-06	3.31E-02	1.22E-03	7.17E-02
Percent of CDF		19.0%	2.9%	16.1%			

C.1 Analysis of Plant-Specific SBO, LOOP, and Total CDF

The industry frequencies were used in the appropriate SPAR model to produce the results shown in Table C-2. Table C-3 shows the results of the uncertainty calculations for total CDF and SBO CDF.

Table C-2. Plant-specific LOOP, SBO, and Total CDF results.

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	Total LOOP % of Total CDF	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Arkansas 1	4.73E-07	1.45E-08	4.59E-07	1.59E-05	2.97%	2.88%	3.31E-02	2.96E-04	4.68E-02	BW (2-loop)
Arkansas 2	5.79E-07	1.61E-07	4.18E-07	1.52E-05	3.82%	2.76%	3.31E-02	1.65E-03	7.66E-03	CE (2-loop)
Beaver Valley 1	1.16E-06	3.57E-09	1.16E-06	2.92E-05	3.98%	3.97%	3.31E-02	1.37E-04	2.55E-01	WE (3-loop)
Beaver Valley 2	7.29E-07	2.86E-08	7.01E-07	3.01E-05	2.42%	2.33%	3.31E-02	1.82E-04	1.16E-01	WE (3-loop)
Braidwood 1	4.39E-06	3.16E-07	4.07E-06	4.25E-05	10.31%	9.57%	3.31E-02	3.51E-04	3.50E-01	WE (4-loop)
Braidwood 2	4.39E-06	3.16E-07	4.07E-06	4.25E-05	10.31%	9.57%	3.31E-02	3.51E-04	3.50E-01	WE (4-loop)
Browns Ferry 2	2.21E-07	1.18E-07	1.03E-07	4.33E-07	51.11%	23.76%	3.31E-02	2.81E-05	1.11E-01	BWR 3/4 (BWR with HPCI)
Browns Ferry 3	3.01E-07	1.98E-07	1.03E-07	5.12E-07	58.79%	20.04%	3.31E-02	2.77E-05	1.12E-01	BWR 3/4 (BWR with HPCI)
Brunswick 1	9.98E-07	2.27E-07	7.72E-07	4.86E-06	20.56%	15.89%	3.31E-02	2.00E-03	1.17E-02	BWR 3/4 (BWR with HPCI)
Brunswick 2	9.98E-07	2.27E-07	7.72E-07	4.86E-06	20.56%	15.89%	3.31E-02	2.00E-03	1.17E-02	BWR 3/4 (BWR with HPCI)
Byron 1	4.47E-06	3.46E-07	4.13E-06	4.29E-05	10.44%	9.63%	3.31E-02	3.51E-04	3.55E-01	WE (4-loop)
Byron 2	4.47E-06	3.46E-07	4.13E-06	4.29E-05	10.44%	9.63%	3.31E-02	3.51E-04	3.55E-01	WE (4-loop)
Callaway	6.79E-06	1.08E-07	6.68E-06	1.16E-05	58.56%	57.64%	3.31E-02	4.11E-03	4.91E-02	WE (4-loop)
Calvert Cliffs 1	1.37E-06	4.44E-08	1.32E-06	7.13E-05	1.92%	1.85%	3.31E-02	3.66E-04	1.09E-01	CE (2-loop)
Calvert Cliffs 2	1.37E-06	4.44E-08	1.32E-06	7.13E-05	1.92%	1.85%	3.31E-02	3.66E-04	1.09E-01	CE (2-loop)
Catawba 1	6.30E-06	3.23E-07	5.97E-06	1.04E-05	60.75%	57.63%	3.31E-02	5.82E-04	3.10E-01	WE (4-loop)
Catawba 2	6.30E-06	3.23E-07	5.97E-06	1.04E-05	60.75%	57.63%	3.31E-02	5.82E-04	3.10E-01	WE (4-loop)
Clinton 1	4.68E-06	2.08E-07	4.47E-06	4.95E-06	94.39%	90.18%	3.31E-02	4.44E-03	3.04E-02	BWR 5/6 (BWR with HPCS)
Columbia 2	1.02E-05	3.37E-06	6.82E-06	1.14E-05	89.61%	59.98%	3.31E-02	4.08E-03	5.05E-02	BWR 5/6 (BWR with HPCS)
Comanche Peak 1	1.77E-05	1.08E-07	1.76E-05	2.00E-05	88.41%	87.87%	3.31E-02	3.97E-03	1.34E-01	WE (4-loop)
Comanche Peak 2	1.77E-05	1.08E-07	1.76E-05	2.00E-05	88.41%	87.87%	3.31E-02	3.97E-03	1.34E-01	WE (4-loop)
Cook 1	7.23E-06	9.78E-08	7.14E-06	3.73E-05	19.38%	19.11%	3.31E-02	1.92E-03	1.12E-01	WE (4-loop)
Cook 2	7.23E-06	9.78E-08	7.14E-06	3.73E-05	19.38%	19.11%	3.31E-02	1.92E-03	1.12E-01	WE (4-loop)
Cooper	9.10E-06	1.09E-06	8.01E-06	1.57E-04	5.80%	5.10%	3.31E-02	2.00E-03	1.21E-01	BWR 3/4 (BWR with HPCI)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	Total LOOP % of Total CDF	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Crystal River 3	1.12E-06	7.00E-07	4.16E-07	2.32E-05	4.82%	1.79%	3.31E-02	2.20E-03	5.71E-03	BW (2-loop)
Davis-Besse	1.75E-06	1.41E-06	3.30E-07	1.87E-05	9.35%	1.77%	3.31E-02	2.71E-03	3.68E-03	BW (2-loop)
Diablo Canyon 1	5.93E-07	5.66E-08	5.37E-07	4.90E-06	12.12%	10.96%	3.31E-02	2.34E-04	6.93E-02	WE (4-loop)
Diablo Canyon 2	5.93E-07	5.66E-08	5.37E-07	4.90E-06	12.12%	10.96%	3.31E-02	2.34E-04	6.93E-02	WE (4-loop)
Dresden 2	1.27E-07	8.58E-08	4.08E-08	8.07E-07	15.68%	5.05%	3.31E-02	1.36E-05	9.06E-02	BWR 1/2/3 (BWR with IC)
Dresden 3	1.27E-07	8.58E-08	4.08E-08	8.07E-07	15.68%	5.05%	3.31E-02	1.36E-05	9.06E-02	BWR 1/2/3 (BWR with IC)
Duane Arnold	6.26E-06	1.20E-07	6.14E-06	6.82E-06	91.83%	90.07%	3.31E-02	5.14E-03	3.61E-02	BWR 3/4 (BWR with HPCI)
Farley 1	3.30E-06	7.93E-07	2.51E-06	8.62E-05	3.83%	2.91%	3.31E-02	2.98E-04	2.54E-01	WE (3-loop)
Farley 2	3.30E-06	7.93E-07	2.51E-06	8.62E-05	3.83%	2.91%	3.31E-02	2.98E-04	2.54E-01	WE (3-loop)
Fermi 2	7.98E-07	7.35E-07	6.35E-08	4.29E-06	18.59%	1.48%	3.31E-02	2.09E-05	9.17E-02	BWR 3/4 (BWR with HPCI)
FitzPatrick	5.78E-07	3.40E-08	5.44E-07	2.09E-06	27.71%	26.08%	3.31E-02	1.40E-04	1.17E-01	BWR 3/4 (BWR with HPCI)
Fort Calhoun	7.54E-06	5.87E-07	6.96E-06	1.44E-05	52.45%	48.36%	3.31E-02	1.84E-03	1.14E-01	CE (2-loop)
Ginna	9.24E-06	2.79E-08	9.21E-06	1.57E-05	58.97%	58.79%	3.31E-02	1.85E-03	1.50E-01	WE (2-loop)
Grand Gulf	7.97E-06	4.71E-06	3.26E-06	8.66E-06	92.08%	37.68%	3.31E-02	4.95E-03	1.99E-02	BWR 5/6 (BWR with HPCS)
Harris	1.86E-05	1.11E-07	1.85E-05	4.49E-05	41.38%	41.13%	3.31E-02	4.24E-03	1.32E-01	WE (3-loop)
Hatch 1	2.18E-06	1.32E-06	8.63E-07	1.13E-05	19.34%	7.66%	3.31E-02	2.80E-04	9.32E-02	BWR 3/4 (BWR with HPCI)
Hatch 2	2.18E-06	1.32E-06	8.63E-07	1.13E-05	19.34%	7.66%	3.31E-02	2.80E-04	9.32E-02	BWR 3/4 (BWR with HPCI)
Hope Creek	3.52E-06	1.18E-06	2.34E-06	9.11E-06	38.62%	25.64%	3.31E-02	6.18E-04	1.14E-01	BWR 3/4 (BWR with HPCI)
Indian Point 2	1.36E-06	1.08E-06	2.82E-07	5.09E-06	26.78%	5.54%	3.31E-02	3.02E-04	2.82E-02	WE (4-loop)
Indian Point 3	2.62E-06	5.76E-07	2.04E-06	5.80E-06	45.19%	35.25%	3.31E-02	3.49E-04	1.77E-01	WE (4-loop)
Kewaunee	4.03E-06	2.85E-07	3.75E-06	6.86E-06	58.79%	54.63%	3.31E-02	2.02E-03	5.60E-02	WE (2-loop)
La Salle 1	6.56E-07	2.51E-07	4.05E-07	1.61E-06	40.68%	25.11%	3.31E-02	2.51E-04	4.87E-02	BWR 5/6 (BWR with HPCS)
La Salle 2	6.56E-07	2.51E-07	4.05E-07	1.61E-06	40.68%	25.11%	3.31E-02	2.51E-04	4.87E-02	BWR 5/6 (BWR with HPCS)
Limerick 1	8.06E-07	4.89E-07	3.17E-07	1.76E-06	45.78%	17.98%	3.31E-02	1.35E-04	7.08E-02	BWR 1/2/3 (BWR with IC)
Limerick 2	8.06E-07	4.89E-07	3.17E-07	1.76E-06	45.78%	17.98%	3.31E-02	1.35E-04	7.08E-02	BWR 3/4 (BWR with HPCI)
McGuire 1	3.64E-06	1.90E-08	3.62E-06	5.29E-06	68.75%	68.39%	3.31E-02	6.43E-04	1.70E-01	WE (4-loop)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	Total LOOP % of Total CDF	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
McGuire 2	3.64E-06	1.90E-08	3.62E-06	5.29E-06	68.75%	68.39%	3.31E-02	6.43E-04	1.70E-01	WE (4-loop)
Millstone 2	7.69E-07	2.35E-07	5.33E-07	1.67E-05	4.61%	3.20%	3.31E-02	2.87E-04	5.62E-02	CE (2-loop)
Millstone 3	1.38E-06	2.23E-08	1.36E-06	6.32E-06	21.86%	21.50%	3.31E-02	2.73E-04	1.50E-01	WE (4-loop)
Monticello	1.54E-06	3.15E-08	1.51E-06	6.03E-06	25.54%	25.02%	3.31E-02	2.09E-03	2.18E-02	BWR 3/4 (BWR with HPCI)
Nine Mile Pt. 1	1.26E-06	3.86E-08	1.22E-06	2.73E-06	46.06%	44.65%	3.31E-02	2.51E-03	1.47E-02	BWR 1/2/3 (BWR with IC)
Nine Mile Pt. 2	3.01E-06	1.80E-06	1.21E-06	1.46E-05	20.57%	8.28%	3.31E-02	1.85E-03	1.98E-02	BWR 5/6 (BWR with HPCS)
North Anna 1	7.79E-07	1.08E-07	6.71E-07	7.90E-06	9.85%	8.48%	3.31E-02	7.14E-05	2.84E-01	WE (3-loop)
North Anna 2	7.79E-07	1.08E-07	6.71E-07	7.90E-06	9.85%	8.48%	3.31E-02	7.14E-05	2.84E-01	WE (3-loop)
Oconee 1	2.06E-06	1.41E-08	2.05E-06	5.92E-06	34.78%	34.54%	3.31E-02	1.98E-03	3.12E-02	BW (2-loop)
Oconee 2	2.06E-06	1.41E-08	2.05E-06	5.92E-06	34.78%	34.54%	3.31E-02	1.98E-03	3.12E-02	BW (2-loop)
Oconee 3	2.06E-06	1.41E-08	2.05E-06	5.92E-06	34.78%	34.54%	3.31E-02	1.98E-03	3.12E-02	BW (2-loop)
Oyster Creek	1.53E-06	3.61E-07	1.17E-06	3.63E-06	42.09%	32.14%	3.31E-02	1.84E-03	1.92E-02	BWR 1/2/3 (BWR with IC)
Palisades	7.71E-06	3.59E-07	7.36E-06	1.72E-05	44.78%	42.70%	3.31E-02	1.94E-03	1.15E-01	CE (2-loop)
Palo Verde 1	2.89E-06	6.38E-07	2.25E-06	7.37E-06	39.21%	30.56%	3.31E-02	8.98E-04	7.57E-02	CE (2-loop)
Palo Verde 2	2.89E-06	6.38E-07	2.25E-06	7.37E-06	39.21%	30.56%	3.31E-02	8.98E-04	7.57E-02	CE (2-loop)
Palo Verde 3	2.89E-06	6.38E-07	2.25E-06	7.37E-06	39.21%	30.56%	3.31E-02	8.98E-04	7.57E-02	CE (2-loop)
Peach Bottom 2	1.44E-06	1.76E-07	1.26E-06	7.82E-06	18.36%	16.11%	3.31E-02	1.20E-03	3.17E-02	BWR 3/4 (BWR with HPCI)
Peach Bottom 3	1.44E-06	1.76E-07	1.26E-06	7.82E-06	18.36%	16.11%	3.31E-02	1.20E-03	3.17E-02	BWR 3/4 (BWR with HPCI)
Perry	2.95E-07	1.38E-07	1.57E-07	3.56E-06	8.30%	4.41%	3.31E-02	4.08E-03	1.16E-03	BWR 5/6 (BWR with HPCS)
Pilgrim	1.02E-07	6.14E-08	4.11E-08	1.89E-05	0.54%	0.22%	3.31E-02	1.84E-03	6.75E-04	BWR 3/4 (BWR with HPCI)
Point Beach 1	2.95E-06	2.42E-06	5.26E-07	2.87E-05	10.29%	1.83%	3.31E-02	3.51E-05	4.52E-01	WE (2-loop)
Point Beach 2	2.95E-06	2.42E-06	5.26E-07	2.87E-05	10.29%	1.83%	3.31E-02	3.51E-05	4.52E-01	WE (2-loop)
Prairie Island 1	1.29E-06	3.01E-08	1.26E-06	5.27E-06	24.44%	23.87%	3.31E-02	1.12E-04	3.40E-01	WE (2-loop)
Prairie Island 2	1.29E-06	3.01E-08	1.26E-06	5.27E-06	24.44%	23.87%	3.31E-02	1.12E-04	3.40E-01	WE (2-loop)
Quad Cities 1	1.04E-06	9.96E-07	4.27E-08	1.83E-06	56.75%	2.33%	3.31E-02	1.27E-05	1.02E-01	BWR 3/4 (BWR with HPCI)
Quad Cities 2	1.04E-06	9.96E-07	4.27E-08	1.83E-06	56.75%	2.33%	3.31E-02	1.27E-05	1.02E-01	BWR 3/4 (BWR with HPCI)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	Total LOOP % of Total CDF	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
River Bend	7.35E-06	1.54E-07	7.19E-06	7.65E-06	96.08%	94.06%	3.31E-02	4.25E-03	5.11E-02	BWR 5/6 (BWR with HPCS)
Robinson 2	1.03E-05	2.08E-06	8.27E-06	1.41E-05	73.34%	58.60%	3.31E-02	2.09E-03	1.20E-01	WE (3-loop)
Salem 1	3.23E-06	1.66E-07	3.07E-06	7.33E-06	44.16%	41.89%	3.31E-02	7.66E-04	1.21E-01	WE (4-loop)
Salem 2	3.23E-06	1.66E-07	3.07E-06	7.33E-06	44.16%	41.89%	3.31E-02	7.66E-04	1.21E-01	WE (4-loop)
San Onofre 2	2.96E-06	1.38E-06	1.59E-06	2.83E-05	10.45%	5.59%	3.31E-02	2.49E-04	1.92E-01	CE (2-loop)
San Onofre 3	2.96E-06	1.38E-06	1.59E-06	2.83E-05	10.45%	5.59%	3.31E-02	2.49E-04	1.92E-01	CE (2-loop)
Seabrook	1.10E-05	6.72E-08	1.09E-05	4.10E-05	26.73%	26.57%	3.31E-02	2.66E-03	1.24E-01	WE (4-loop)
Sequoyah 1	1.97E-06	2.15E-08	1.95E-06	3.15E-05	6.25%	6.18%	3.31E-02	4.82E-04	1.22E-01	WE (4-loop)
Sequoyah 2	1.97E-06	2.15E-08	1.95E-06	3.15E-05	6.25%	6.18%	3.31E-02	4.82E-04	1.22E-01	WE (4-loop)
South Texas 1	1.07E-06	5.14E-08	1.02E-06	4.71E-06	22.72%	21.63%	3.31E-02	2.57E-04	1.20E-01	WE (4-loop)
South Texas 2	1.07E-06	5.14E-08	1.02E-06	4.71E-06	22.72%	21.63%	3.31E-02	2.57E-04	1.20E-01	WE (4-loop)
St. Lucie 1	1.02E-06	4.00E-07	6.17E-07	3.23E-05	3.15%	1.91%	3.31E-02	2.92E-04	6.38E-02	CE (2-loop)
St. Lucie 2	1.17E-06	4.43E-08	1.13E-06	3.08E-05	3.82%	3.67%	3.31E-02	2.92E-04	1.17E-01	CE (2-loop)
Summer	8.69E-06	5.29E-07	8.16E-06	1.38E-05	62.85%	59.02%	3.31E-02	1.91E-03	1.29E-01	WE (3-loop)
Surry 1	1.34E-06	7.01E-07	6.42E-07	3.23E-06	41.62%	19.89%	3.31E-02	1.88E-04	1.03E-01	WE (3-loop)
Surry 2	1.34E-06	7.01E-07	6.42E-07	3.23E-06	41.62%	19.89%	3.31E-02	1.88E-04	1.03E-01	WE (3-loop)
Susquehanna 1	2.53E-06	2.28E-06	2.52E-07	3.52E-06	71.86%	7.15%	3.31E-02	8.28E-05	9.19E-02	BWR 3/4 (BWR with HPCI)
Susquehanna 2	2.53E-06	2.28E-06	2.52E-07	3.52E-06	71.86%	7.15%	3.31E-02	8.28E-05	9.19E-02	BWR 3/4 (BWR with HPCI)
Three Mile Isl 1	5.79E-07	4.52E-08	5.33E-07	6.37E-06	9.08%	8.37%	3.31E-02	1.99E-03	8.10E-03	BW (2-loop)
Turkey Point 3	2.87E-06	2.27E-08	2.85E-06	2.72E-05	10.55%	10.46%	3.31E-02	3.22E-04	2.67E-01	WE (3-loop)
Turkey Point 4	2.87E-06	2.27E-08	2.85E-06	2.72E-05	10.55%	10.46%	3.31E-02	3.22E-04	2.67E-01	WE (3-loop)
Vermont Yankee	6.54E-07	6.53E-07	8.44E-10	2.59E-06	25.27%	0.03%	3.31E-02	9.14E-06	2.79E-03	BWR 3/4 (BWR with HPCI)
Vogtle 1	2.54E-06	3.02E-07	2.24E-06	3.30E-05	7.70%	6.79%	3.31E-02	2.91E-03	2.33E-02	WE (4-loop)
Vogtle 2	2.54E-06	3.02E-07	2.24E-06	3.30E-05	7.70%	6.79%	3.31E-02	2.91E-03	2.33E-02	WE (4-loop)
Waterford 3	9.88E-06	4.12E-07	9.46E-06	1.86E-05	53.11%	50.90%	3.31E-02	2.62E-03	1.09E-01	CE (2-loop)
Watts Bar 1	9.23E-07	2.84E-08	8.95E-07	3.18E-05	2.90%	2.81%	3.31E-02	2.23E-04	1.21E-01	WE (4-loop)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	Total LOOP % of Total CDF	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Wolf Creek	7.93E-06	1.18E-06	6.76E-06	1.60E-05	49.44%	42.11%	3.31E-02	4.11E-03	4.97E-02	WE (4-loop)

Table C-3. Plant-specific CDF and SBO uncertainty table.

	Total CDF (1/rcry)					SBO CDF (1/rcry)				
Plant	Min Cut	5%	Median	Mean	95%	Min Cut	5%	Median	Mean	95%
Arkansas 1	1.59E-05	7.64E-07	5.61E-06	1.65E-05	7.18E-05	4.59E-07	8.94E-09	1.49E-07	5.98E-07	2.31E-06
Arkansas 2	1.47E-05	4.42E-07	4.42E-06	1.51E-05	6.62E-05	4.17E-07	3.87E-09	1.07E-07	6.50E-07	2.25E-06
Duane Arnold	6.54E-06	2.69E-07	2.45E-06	7.07E-06	2.76E-05	5.87E-06	5.52E-08	1.57E-06	5.97E-06	2.50E-05
Browns Ferry 2	4.27E-07	2.67E-08	2.22E-07	5.87E-07	2.19E-06	1.00E-07	2.50E-10	2.48E-08	2.11E-07	8.05E-07
Browns Ferry 3	5.01E-07	2.66E-08	2.65E-07	8.12E-07	2.98E-06	9.88E-08	2.29E-10	2.43E-08	2.21E-07	7.99E-07
Brunswick 1	4.76E-06	5.50E-07	3.30E-06	5.08E-06	1.56E-05	7.30E-07	4.43E-09	1.35E-07	8.25E-07	3.37E-06
Brunswick 2	4.76E-06	5.50E-07	3.30E-06	5.08E-06	1.56E-05	7.30E-07	4.43E-09	1.35E-07	8.25E-07	3.37E-06
Braidwood 2	4.25E-05	3.09E-06	2.18E-05	4.58E-05	1.64E-04	4.05E-06	1.16E-07	1.83E-06	5.67E-06	2.13E-05
Braidwood 1	4.25E-05	3.09E-06	2.18E-05	4.58E-05	1.64E-04	4.05E-06	1.16E-07	1.83E-06	5.67E-06	2.13E-05
Beaver Valley 1	2.92E-05	5.70E-07	4.20E-06	2.76E-05	1.15E-04	1.16E-06	1.50E-08	3.95E-07	2.18E-06	9.17E-06
Beaver Valley 2	3.01E-05	7.78E-07	4.80E-06	3.17E-05	1.35E-04	6.94E-07	6.38E-09	1.92E-07	1.13E-06	4.91E-06
Byron 1	4.27E-05	2.84E-06	2.07E-05	4.30E-05	1.55E-04	4.05E-06	1.14E-07	1.70E-06	5.72E-06	2.32E-05
Byron 2	4.27E-05	2.84E-06	2.07E-05	4.30E-05	1.55E-04	4.05E-06	1.14E-07	1.70E-06	5.72E-06	2.32E-05
Callaway	1.18E-05	8.46E-07	5.79E-06	1.21E-05	4.23E-05	6.68E-06	1.06E-07	1.96E-06	6.45E-06	2.60E-05
Catawba 1	1.02E-05	1.23E-06	5.43E-06	1.04E-05	3.51E-05	5.90E-06	1.87E-08	1.38E-06	6.71E-06	2.84E-05
Catawba 2	1.02E-05	1.23E-06	5.43E-06	1.04E-05	3.51E-05	5.90E-06	1.87E-08	1.38E-06	6.71E-06	2.84E-05
Calvert Cliffs 1	7.12E-05	3.06E-06	2.69E-05	7.14E-05	2.89E-04	1.32E-06	5.26E-09	4.25E-07	1.64E-06	6.45E-06
Calvert Cliffs 2	7.12E-05	3.06E-06	2.69E-05	7.14E-05	2.89E-04	1.32E-06	5.26E-09	4.25E-07	1.64E-06	6.45E-06
Clinton 1	4.95E-06	1.40E-07	1.62E-06	5.66E-06	2.27E-05	4.46E-06	4.26E-08	1.17E-06	5.01E-06	2.13E-05
Columbia 2	1.07E-05	5.98E-07	4.90E-06	1.19E-05	4.49E-05	6.50E-06	6.79E-08	1.71E-06	7.19E-06	2.92E-05
Cook 1	3.72E-05	1.13E-06	1.04E-05	4.06E-05	1.57E-04	7.06E-06	6.22E-08	2.19E-06	8.22E-06	3.20E-05
Cook 2	3.72E-05	1.13E-06	1.04E-05	4.06E-05	1.57E-04	7.06E-06	6.22E-08	2.19E-06	8.22E-06	3.20E-05
Cooper	1.56E-04	3.08E-06	3.52E-05	1.62E-04	7.47E-04	7.63E-06	7.92E-08	2.55E-06	8.72E-06	3.65E-05
Comanche Peak 1	1.99E-05	1.49E-06	8.40E-06	2.12E-05	7.87E-05	1.75E-05	3.41E-07	6.22E-06	1.99E-05	8.05E-05
Comanche Peak 2	1.99E-05	1.49E-06	8.40E-06	2.12E-05	7.87E-05	1.75E-05	3.41E-07	6.22E-06	1.99E-05	8.05E-05
Crystal River 3	2.31E-05	8.30E-07	6.26E-06	2.16E-05	7.98E-05	4.13E-07	7.52E-10	4.73E-08	4.93E-07	2.20E-06
Davis-Besse	1.86E-05	8.98E-07	7.43E-06	2.01E-05	7.90E-05	3.27E-07	1.21E-09	5.07E-08	3.76E-07	1.60E-06
Diablo Canyon 1	4.89E-06	3.82E-07	2.39E-06	4.96E-06	1.78E-05	5.36E-07	1.60E-08	1.92E-07	6.06E-07	2.34E-06
Diablo Canyon 2	4.89E-06	3.82E-07	2.39E-06	4.96E-06	1.78E-05	5.36E-07	1.60E-08	1.92E-07	6.06E-07	2.34E-06
Dresden 2	7.98E-07	2.63E-08	2.65E-07	8.84E-07	3.52E-06	3.89E-08	3.20E-11	5.74E-09	1.07E-07	3.49E-07
Dresden 3	7.98E-07	2.63E-08	2.65E-07	8.84E-07	3.52E-06	3.89E-08	3.20E-11	5.74E-09	1.07E-07	3.49E-07
Farley 1	8.55E-05	2.54E-06	2.02E-05	8.76E-05	3.58E-04	2.51E-06	2.06E-08	6.31E-07	3.60E-06	1.50E-05
Farley 2	8.55E-05	2.54E-06	2.02E-05	8.76E-05	3.58E-04	2.51E-06	2.06E-08	6.31E-07	3.60E-06	1.50E-05
Fort Calhoun	1.42E-05	1.07E-06	6.90E-06	1.53E-05	5.43E-05	6.96E-06	5.76E-08	2.20E-06	8.08E-06	3.48E-05
Fermi 2	4.11E-06	1.37E-07	1.54E-06	4.41E-06	1.77E-05	5.91E-08	7.12E-11	9.72E-09	1.05E-07	3.77E-07

	Total CDF (1/rcry)					SBO CDF (1/rcry)				
Plant	Min Cut	5%	Median	Mean	95%	Min Cut	5%	Median	Mean	95%
FitzPatrick	2.02E-06	1.74E-07	1.12E-06	2.05E-06	6.49E-06	4.88E-07	7.23E-09	1.82E-07	5.44E-07	2.01E-06
Grand Gulf	7.99E-06	3.89E-07	3.41E-06	8.69E-06	3.26E-05	3.07E-06	2.72E-08	6.87E-07	3.42E-06	1.48E-05
Ginna	1.43E-05	2.21E-06	8.85E-06	1.46E-05	4.48E-05	7.82E-06	1.37E-07	2.71E-06	9.06E-06	3.82E-05
Harris	4.48E-05	4.01E-06	2.35E-05	4.75E-05	1.64E-04	1.85E-05	6.33E-07	7.98E-06	1.96E-05	7.62E-05
Hatch 1	1.10E-05	1.08E-06	6.26E-06	1.25E-05	3.95E-05	8.59E-07	1.31E-08	2.82E-07	1.06E-06	4.13E-06
Hatch 2	1.10E-05	1.08E-06	6.26E-06	1.25E-05	3.95E-05	8.59E-07	1.31E-08	2.82E-07	1.06E-06	4.13E-06
Hope Creek	9.04E-06	5.81E-07	4.37E-06	9.60E-06	3.53E-05	2.28E-06	3.93E-08	8.49E-07	3.48E-06	1.45E-05
Indian Point 2	5.07E-06	4.40E-07	2.14E-06	5.20E-06	1.79E-05	2.78E-07	1.04E-09	3.78E-08	3.05E-07	1.25E-06
Indian Point 3	4.56E-06	6.27E-07	2.87E-06	4.85E-06	1.49E-05	7.79E-07	4.52E-09	1.65E-07	9.49E-07	3.74E-06
Kewaunee	6.82E-06	9.30E-07	3.90E-06	6.85E-06	2.18E-05	3.72E-06	7.89E-08	1.17E-06	3.75E-06	1.56E-05
Limerick 1	1.75E-06	1.66E-07	9.88E-07	2.14E-06	7.32E-06	3.15E-07	7.85E-09	1.33E-07	4.42E-07	1.61E-06
Limerick 2	1.75E-06	1.66E-07	9.88E-07	2.14E-06	7.32E-06	3.15E-07	7.85E-09	1.33E-07	4.42E-07	1.61E-06
La Salle 1	1.58E-06	1.97E-07	9.97E-07	2.04E-06	6.53E-06	3.91E-07	3.79E-09	9.75E-08	6.66E-07	2.70E-06
La Salle 2	1.58E-06	1.97E-07	9.97E-07	2.04E-06	6.53E-06	3.91E-07	3.79E-09	9.75E-08	6.66E-07	2.70E-06
McGuire 1	5.26E-06	3.92E-07	2.35E-06	5.47E-06	1.91E-05	3.62E-06	1.08E-08	7.96E-07	4.09E-06	1.82E-05
McGuire 2	5.26E-06	3.92E-07	2.35E-06	5.47E-06	1.91E-05	3.62E-06	1.08E-08	7.96E-07	4.09E-06	1.82E-05
Millstone 2	1.65E-05	2.55E-06	1.14E-05	1.91E-05	6.18E-05	5.29E-07	1.01E-08	1.82E-07	6.41E-07	2.59E-06
Millstone 3	6.06E-06	8.07E-07	3.64E-06	6.46E-06	2.01E-05	1.36E-06	4.66E-08	5.78E-07	1.57E-06	6.28E-06
Monticello	5.91E-06	4.88E-07	3.43E-06	6.38E-06	2.14E-05	1.47E-06	8.43E-09	3.11E-07	1.71E-06	6.79E-06
North Anna 1	7.89E-06	4.03E-07	2.23E-06	7.80E-06	2.77E-05	6.69E-07	1.56E-08	2.75E-07	9.54E-07	3.83E-06
North Anna 2	7.89E-06	4.03E-07	2.23E-06	7.80E-06	2.77E-05	6.69E-07	1.56E-08	2.75E-07	9.54E-07	3.83E-06
Nine Mile Pt. 1	2.67E-06	1.98E-07	1.47E-06	2.81E-06	9.40E-06	1.18E-06	2.97E-08	4.54E-07	1.34E-06	5.21E-06
Nine Mile Pt. 2	1.40E-05	9.50E-07	6.89E-06	1.62E-05	5.54E-05	1.18E-06	3.01E-08	4.09E-07	1.23E-06	5.01E-06
Oconee 1	5.91E-06	3.64E-07	2.68E-06	5.87E-06	2.12E-05	2.04E-06	1.94E-08	4.63E-07	2.11E-06	8.47E-06
Oconee 2	5.91E-06	3.64E-07	2.68E-06	5.87E-06	2.12E-05	2.04E-06	1.94E-08	4.63E-07	2.11E-06	8.47E-06
Oconee 3	5.91E-06	3.64E-07	2.68E-06	5.87E-06	2.12E-05	2.04E-06	1.94E-08	4.63E-07	2.11E-06	8.47E-06
Oyster Creek	3.63E-06	3.08E-07	1.78E-06	3.70E-06	1.23E-05	1.17E-06	9.41E-09	2.38E-07	1.36E-06	5.62E-06
Palisades	1.72E-05	1.71E-06	1.10E-05	1.83E-05	5.71E-05	7.34E-06	9.03E-08	2.29E-06	8.31E-06	3.62E-05
Point Beach 1	2.86E-05	1.91E-06	1.30E-05	2.78E-05	1.03E-04	5.24E-07	3.17E-09	1.18E-07	6.38E-07	2.59E-06
Point Beach 2	2.86E-05	1.91E-06	1.30E-05	2.78E-05	1.03E-04	5.24E-07	3.17E-09	1.18E-07	6.38E-07	2.59E-06
Peach Bottom 2	7.77E-06	3.71E-07	3.14E-06	8.35E-06	3.01E-05	1.22E-06	3.48E-09	2.03E-07	1.33E-06	5.66E-06
Peach Bottom 3	7.77E-06	3.71E-07	3.14E-06	8.35E-06	3.01E-05	1.22E-06	3.48E-09	2.03E-07	1.33E-06	5.66E-06
Perry	3.53E-06	8.11E-08	8.41E-07	3.78E-06	1.57E-05	1.52E-07	1.73E-09	4.28E-08	2.46E-07	9.38E-07
Pilgrim	1.89E-05	3.52E-07	4.53E-06	1.90E-05	7.69E-05	3.84E-08	2.50E-11	4.41E-09	7.76E-08	3.05E-07
Prairie Island 1	5.25E-06	9.94E-07	3.62E-06	5.50E-06	1.60E-05	1.26E-06	3.68E-08	5.46E-07	1.38E-06	5.24E-06
Prairie Island 2	5.25E-06	9.94E-07	3.62E-06	5.50E-06	1.60E-05	1.26E-06	3.68E-08	5.46E-07	1.38E-06	5.24E-06
Palo Verde 2	7.33E-06	6.63E-07	4.11E-06	9.32E-06	3.33E-05	2.23E-06	3.63E-09	3.51E-07	2.67E-06	1.26E-05
Palo Verde 3	7.33E-06	6.63E-07	4.11E-06	9.32E-06	3.33E-05	2.23E-06	3.63E-09	3.51E-07	2.67E-06	1.26E-05
Palo Verde 1	7.33E-06	6.63E-07	4.11E-06	9.32E-06	3.33E-05	2.23E-06	3.63E-09	3.51E-07	2.67E-06	1.26E-05

Plant	Total CDF (1/rcry) Min Cut	5%	Median	Mean	95%	SBO CDF (1/rcry) Min Cut	5%	Median	Mean	95%
Quad Cities 1	1.75E-06	4.45E-08	5.56E-07	1.89E-06	7.43E-06	2.91E-08	2.33E-11	4.43E-09	8.76E-08	2.82E-07
Quad Cities 2	1.75E-06	4.45E-08	5.56E-07	1.89E-06	7.43E-06	2.91E-08	2.33E-11	4.43E-09	8.76E-08	2.82E-07
River Bend	7.62E-06	2.81E-07	3.03E-06	9.21E-06	3.65E-05	7.19E-06	1.39E-07	2.67E-06	8.13E-06	3.32E-05
Robinson 2	1.40E-05	1.50E-06	7.78E-06	1.45E-05	4.68E-05	8.19E-06	1.33E-07	2.72E-06	9.27E-06	3.82E-05
Salem 1	7.25E-06	6.89E-07	3.81E-06	8.24E-06	2.83E-05	3.00E-06	1.36E-08	6.19E-07	3.40E-06	1.44E-05
Salem 2	7.25E-06	6.89E-07	3.81E-06	8.24E-06	2.83E-05	3.00E-06	1.36E-08	6.19E-07	3.40E-06	1.44E-05
Seabrook	4.08E-05	1.79E-06	1.20E-05	4.14E-05	1.58E-04	1.07E-05	2.05E-07	4.03E-06	1.16E-05	4.58E-05
Sequoyah 1	3.14E-05	7.45E-07	5.89E-06	3.03E-05	1.21E-04	1.93E-06	3.05E-08	6.61E-07	2.52E-06	1.02E-05
Sequoyah 2	3.14E-05	7.45E-07	5.89E-06	3.03E-05	1.21E-04	1.93E-06	3.05E-08	6.61E-07	2.52E-06	1.02E-05
San Onofre 2	2.83E-05	2.45E-06	1.30E-05	3.04E-05	1.09E-04	1.57E-06	9.76E-09	4.13E-07	2.48E-06	1.16E-05
San Onofre 3	2.83E-05	2.45E-06	1.30E-05	3.04E-05	1.09E-04	1.57E-06	9.76E-09	4.13E-07	2.48E-06	1.16E-05
South Texas 1	4.92E-06	3.30E-07	2.33E-06	5.13E-06	1.83E-05	1.01E-06	1.72E-08	3.42E-07	1.20E-06	4.61E-06
South Texas 2	4.92E-06	3.30E-07	2.33E-06	5.13E-06	1.83E-05	1.01E-06	1.72E-08	3.42E-07	1.20E-06	4.61E-06
St. Lucie 1	3.12E-05	1.43E-06	1.36E-05	3.05E-05	1.18E-04	6.11E-07	4.88E-09	1.53E-07	9.94E-07	4.11E-06
St. Lucie 2	2.98E-05	1.20E-06	1.17E-05	2.98E-05	1.17E-04	1.12E-06	8.68E-09	3.00E-07	1.66E-06	7.71E-06
Summer	1.37E-05	1.11E-06	6.90E-06	1.45E-05	5.23E-05	8.08E-06	1.37E-07	2.79E-06	8.91E-06	3.58E-05
Surry 1	3.19E-06	3.41E-07	1.85E-06	3.62E-06	1.22E-05	6.34E-07	1.34E-09	1.16E-07	1.00E-06	4.19E-06
Surry 2	3.19E-06	3.41E-07	1.85E-06	3.62E-06	1.22E-05	6.34E-07	1.34E-09	1.16E-07	1.00E-06	4.19E-06
Susquehanna 1	3.47E-06	1.56E-07	1.36E-06	4.63E-06	1.71E-05	2.37E-07	1.57E-09	5.24E-08	2.57E-07	1.13E-06
Susquehanna 2	3.47E-06	1.56E-07	1.36E-06	4.63E-06	1.71E-05	2.37E-07	1.57E-09	5.24E-08	2.57E-07	1.13E-06
Turkey Point 3	2.72E-05	1.28E-06	8.24E-06	2.62E-05	1.07E-04	2.81E-06	5.82E-08	1.02E-06	3.02E-06	1.21E-05
Turkey Point 4	2.72E-05	1.28E-06	8.24E-06	2.62E-05	1.07E-04	2.81E-06	5.82E-08	1.02E-06	3.02E-06	1.21E-05
Three Mile Isl 1	6.36E-06	3.95E-07	2.85E-06	6.69E-06	2.49E-05	5.33E-07	7.44E-09	1.67E-07	7.11E-07	2.86E-06
Vogtle 1	3.29E-05	1.37E-06	6.69E-06	3.45E-05	1.45E-04	2.24E-06	1.95E-08	4.85E-07	2.62E-06	1.01E-05
Vogtle 2	3.29E-05	1.37E-06	6.69E-06	3.45E-05	1.45E-04	2.24E-06	1.95E-08	4.85E-07	2.62E-06	1.01E-05
Vermont Yankee	2.57E-06	2.56E-07	1.39E-06	2.62E-06	8.95E-06	7.01E-10	1.81E-12	1.08E-10	9.61E-10	4.02E-09
Watts Bar 1	3.18E-05	8.48E-07	6.31E-06	3.34E-05	1.33E-04	8.86E-07	9.84E-09	2.68E-07	1.45E-06	6.04E-06
Wolf Creek	1.62E-05	1.22E-06	8.40E-06	1.61E-05	5.57E-05	6.71E-06	1.08E-07	1.95E-06	6.72E-06	2.63E-05
Waterford 3	1.86E-05	1.17E-06	8.63E-06	1.92E-05	6.90E-05	9.46E-06	1.38E-07	3.37E-06	1.03E-05	4.44E-05

Appendix D

Baseline and Sensitivity Case

Input Parameters

Appendix D

Baseline and Sensitivity Case Input Parameters

D.1 SBO Sensitivity Cases

Table D-1. Baseline.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	8.74E-03	0.1	0.9095
FTR (1/h)	8.00E-04	Grid related	1.67E-02	0.2	0.8163
UA	9.00E-03	Severe weather	2.98E-03	0.5	0.6640
		Extreme weather	2.32E-03	1.0	0.5285
		Combined	3.31E-02	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

The FTS, FTLR, and FTR values are from EPIX/RADS for the period 1998 - 2002. The UA value is from the ROP (without fault exposure time) for the period 1998 - 2002. LOOP frequency and nonrestoration curves are from the draft LOOP report (mainly 1997 - 2003).

Table D-2. Baseline (plant-centered LOOPs only).

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	0.00E+00	0.1	0.7289
FTR (1/h)	8.00E-04	Grid related	0.00E+00	0.2	0.5173
UA	9.00E-03	Severe weather	0.00E+00	0.5	0.2758
		Extreme weather	0.00E+00	1.0	0.1400
		Combined	2.38E-03	1.5	0.0807
				2.0	0.0498
				3.0	0.0215
				4.0	0.0103
				6.0	0.0028
				8.0	0.0009
				10.0	0.0003
				12.0	0.0001
				16.0	0.0000
				20.0	0.0000
				24.0	0.0000

Baseline case but considering only the plant-centered LOOPs (and their associated nonrestoration curve).

Table D-3. Baseline (switchyard-centered LOOPs only).

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	0.00E+00	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	8.74E-03	0.1	0.8754
FTR (1/h)	8.00E-04	Grid related	0.00E+00	0.2	0.7402
UA	9.00E-03	Severe weather	0.00E+00	0.5	0.5308
		Extreme weather	0.00E+00	1.0	0.3632
		Combined	8.74E-03	1.5	0.2636
				2.0	0.1979
				3.0	0.1186
				4.0	0.0749
				6.0	0.0330
				8.0	0.0159
				10.0	0.0081
				12.0	0.0043
				16.0	0.0013
				20.0	0.0004
				24.0	0.0002

Baseline case but considering only the switchyard-centered LOOPs (and their associated nonrestoration curve).

Table D-4. Baseline (grid-related LOOPs only).

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	0.00E+00	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	0.00E+00	0.1	0.9593
FTR (1/h)	8.00E-04	Grid related	1.67E-02	0.2	0.8945
UA	9.00E-03	Severe weather	0.00E+00	0.5	0.7604
		Extreme weather	0.00E+00	1.0	0.6168
		Combined	1.67E-02	1.5	0.5099
				2.0	0.4264
				3.0	0.3049
				4.0	0.2224
				6.0	0.1230
				8.0	0.0705
				10.0	0.0415
				12.0	0.0248
				16.0	0.0093
				20.0	0.0036
				24.0	0.0015

Baseline case but considering only the grid-related LOOPs (and their associated nonrestoration curve).

Table D-5. Baseline (severe-weather-related LOOPs only).

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	0.00E+00	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	0.00E+00	0.1	0.8054
FTR (1/h)	8.00E-04	Grid related	0.00E+00	0.2	0.6977
UA	9.00E-03	Severe weather	2.98E-03	0.5	0.5641
		Extreme weather	0.00E+00	1.0	0.4643
		Combined	2.98E-03	1.5	0.4023
				2.0	0.3576
				3.0	0.2951
				4.0	0.2520
				6.0	0.1948
				8.0	0.1577
				10.0	0.1314
				12.0	0.1117
				16.0	0.0841
				20.0	0.0659
				24.0	0.0530

Baseline case but considering only the severe-weather-related LOOPs (and their associated nonrestoration curve).

Table D-6. Baseline (extreme-weather-related LOOPs only).

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	0.00E+00	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	0.00E+00	0.1	1.0000
FTR (1/h)	8.00E-04	Grid related	0.00E+00	0.2	0.9998
UA	9.00E-03	Severe weather	0.00E+00	0.5	0.9993
		Extreme weather	2.32E-03	1.0	0.9980
		Combined	2.32E-03	1.5	0.9965
				2.0	0.9948
				3.0	0.9909
				4.0	0.9864
				6.0	0.9761
				8.0	0.9645
				10.0	0.9518
				12.0	0.9382
				16.0	0.9090
				20.0	0.8777
				24.0	0.8450

Baseline case but considering only the extreme-weather-related LOOPs (and their associated nonrestoration curve).

Table D-7. Summer and EDG 14-Day outage.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Nonrestoration Probability
FTS	4.00E-03	Plant centered	5.24E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	1.92E-02	0.1	0.9095
FTR (1/h)	8.00E-04	Grid related	3.67E-02	0.2	0.8163
UA	4.40E-02	Severe weather	6.56E-03	0.5	0.6640
		Extreme weather	5.10E-03	1.0	0.5285
		Combined	7.28E-02	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

Information from Table 6-1 of the draft LOOP report was used to generate the summer LOOP frequencies. The summer frequency from the data in that table is (17 + 0.5)/(271.0 rcry) = 6.46E-2/rcry. The annual frequency is (17 + 1 + 0.5)/(271.0 + 358.5) = 2.94E-2/rcry. Therefore, the summer multiplier is 6.46E-2/2.94E-2 = 2.20. All five LOOP category baseline frequencies were multiplied by 2.20 for this sensitivity case. The nonrestoration curve is unchanged. In addition, the EDG 14-day outages were assumed to occur only during the five summer months. The EDG UA is then [(80)(5/12) + 112]/[(8760)(5/12)(0.9)] = 0.044.

Table D-8. Non-summer and EDG 14-Day outage.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	4.00E-03	Plant centered	3.38E-04	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	1.24E-03	0.1	0.9095
FTR (1/h)	8.00E-04	Grid related	2.37E-03	0.2	0.8163
UA	3.50E-02	Severe weather	4.23E-04	0.5	0.6640
		Extreme weather	3.29E-04	1.0	0.5285
		Combined	4.70E-03	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

Information from Table 6-1 of the draft LOOP report was used to generate the summer LOOP frequencies. The non-summer frequency from the data in that table is (1 + 0.5)/(358.5 rcry) = 4.18E-3/rcry. The annual frequency is (17 + 1 + 0.5)/(271.0 + 358.5) = 2.94E-2/rcry. Therefore, the non-summer multiplier is 4.18E-3/2.94E-2 = 0.142. All five LOOP category baseline frequencies were multiplied by 0.142 for this sensitivity case. The nonrestoration curve is unchanged. In addition, the EDG 14-day outages were assumed to occur only during the seven non-summer months. The EDG UA is then [(80)(7/12) + 112]/[(8760)(7/12)(0.9)] = 0.035.

Table D-9. 30-minute non-restoration curve.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve Time (h)	Nonrestoration Probability
FTS	4.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	8.74E-03	0.1	0.9787
FTR (1/h)	8.00E-04	Grid related	1.67E-02	0.2	0.9333
UA	9.00E-03	Severe weather	2.98E-03	0.5	0.8189
		Extreme weather	2.32E-03	1.0	0.6810
		Combined	3.31E-02	1.5	0.5737
				2.0	0.4887
				3.0	0.3648
				4.0	0.2811
				6.0	0.1818
				8.0	0.1309
				10.0	0.1035
				12.0	0.0881
				16.0	0.0732
				20.0	0.0664
				24.0	0.0621

The only changes from the baseline are the nonrestoration probabilities. These probabilities were obtained from the 30 minute sensitivity case (on potential bus restoration times) in the draft LOOP report.

Table D-10. Actual bus non-restoration curve.

EDG Parameter	Value (note a)	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve Time (h)	Nonrestoration Probability
FTS	4.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	8.74E-03	0.1	0.9631
FTR (1/h)	8.00E-04	Grid related	1.67E-02	0.2	0.9145
UA	9.00E-03	Severe weather	2.98E-03	0.5	0.8210
		Extreme weather	2.32E-03	1.0	0.7228
		Combined	3.31E-02	1.5	0.6480
				2.0	0.5870
				3.0	0.4920
				4.0	0.4202
				6.0	0.3189
				8.0	0.2515
				10.0	0.2045
				12.0	0.1706
				16.0	0.1265
				20.0	0.1006
				24.0	0.0843

The only changes from the baseline are the nonrestoration probabilities, which were derived from the actual bus restoration times in the draft LOOP report.

Table D-11. EDG total unreliability doubled.

EDG Parameter	Value (note a)	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	8.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	6.00E-03	Switchyard centered	8.74E-03	0.1	0.9095
FTR (1/h)	1.60E-03	Grid related	1.67E-02	0.2	0.8163
UA	1.80E-02	Severe weather	2.98E-03	0.5	0.6640
		Extreme weather	2.32E-03	1.0	0.5285
		Combined	3.31E-02	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

The only changes from the baseline are the EDG parameters, which were arbitrarily set at twice the baseline values.

Table D-12. EDG total unreliability halved.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	2.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	1.50E-03	Switchyard centered	8.74E-03	0.1	0.9095
FTR (1/h)	4.00E-04	Grid related	1.67E-02	0.2	0.8163
UA	4.50E-03	Severe weather	2.98E-03	0.5	0.6640
		Extreme weather	2.32E-03	1.0	0.5285
		Combined	3.31E-02	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

The only changes from the baseline are the EDG parameters, which were arbitrarily set at half the baseline values.

Table D-13. EDG 14-day outage.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve Time (h)	Nonrestoration Probability
FTS	4.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	8.74E-03	0.1	0.9095
FTR (1/h)	8.00E-04	Grid related	1.67E-02	0.2	0.8163
UA	2.30E-02	Severe weather	2.98E-03	0.5	0.6640
		Extreme weather	2.32E-03	1.0	0.5285
		Combined	3.31E-02	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

The only change from the baseline is the EDG UA, which is set at 2.3E-2 to model the potential impacts on UA of plants obtaining approvals for 14-day outages. Assuming 90% critical operation, the baseline UA of 9.0E-3 results in (9.0E-3)(8760h/y)(0.9) = 80.0 h/year. Assuming the licensee enters a 14-day outage once per cycle (18 mo) and the actual outage is 7 days, the extra outage contribution is (1)(7day)/1.5y = 4.67 day/y = 112 h/y. Therefore, the UA is (80.0h+112h)/[(8760h)(0.9)] = 2.3E-2.

Table D-14. EDG 8-hour mission time.

EDG Parameter	Value	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve Time (h)	Nonrestoration Probability
FTS	4.00E-03	Plant centered	2.38E-03	0.0	1.0000
FTLR (1/h)	3.00E-03	Switchyard centered	8.74E-03	0.1	0.9095
FTR (1/h)	8.00E-04	Grid related	1.67E-02	0.2	0.8163
UA	9.00E-03	Severe weather	2.98E-03	0.5	0.6640
		Extreme weather	2.32E-03	1.0	0.5285
		Combined	3.31E-02	1.5	0.4384
				2.0	0.3726
				3.0	0.2825
				4.0	0.2244
				6.0	0.1569
				8.0	0.1216
				10.0	0.1016
				12.0	0.0895
				16.0	0.0763
				20.0	0.0694
				24.0	0.0648

The only change from the baseline is the EDG mission time, which was reduced from 24 hours to 8 hours.

Table D-15. NUREG-1032 inputs (with and without EDG changes).

EDG Parameter	Value (note a)	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve: Time (h)	Composite Nonrestoration Curve: Nonrestoration Probability
FTS	2.00E-02	Plant centered	8.37E-02	0.0	1.0000
FTLR (1/h)	5.90E-03	Switchyard centered		0.1	0.8828
FTR (1/h)	1.80E-03	Grid related	2.19E-02	0.2	0.7144
UA	6.00E-03	Severe weather	6.73E-03	0.5	0.4364
		Extreme weather	2.00E-03	1.0	0.2381
		Combined	1.14E-01	1.5	0.1456
				2.0	0.0991
				3.0	0.0604
				4.0	0.0466
				6.0	0.0355
				8.0	0.0297
				10.0	0.0259
				12.0	0.0233
				16.0	0.0203
				20.0	0.0188
				24.0	0.0182

a. NUREG-1032 lists a single FTR rate of 2.8E-3/h. To split this into FTLR and FTR (>1h), I used the ratios observed from the EPIX data. The EPIX data indicate a combined (FTLR and FTR) rate of 1.32E-3/h, while the FTLR rate is 2.77E-3/h (assuming 1h/d). Therefore, the ratio is 2.77E-3/1.32E-3 = 2.1. For FTLR, the result is (2.8E-3)(2.1) = 5.9E-3/h. The EPIX data indicate a FTR (>1h) of 8.27E-4/h, so the ratio is 8.27E-4/1.32E-3 = 0.63. For FTR (>1h), the result is (2.8E-3)(0.63) = 1.8E-3/h.

Table D-16. NUREG/CR-5496 inputs (with and without EDG changes).

EDG Parameter	Value (note a)	LOOP Category	Frequency (1/y)	Composite Nonrestoration Curve Time (h)	Nonrestoration Probability
FTS	5.00E-03	Plant centered	4.00E-02	0.0	1.0000
FTLR (1/h)	5.00E-03	Switchyard centered		0.1	0.9583
FTR (1/h)	1.30E-03	Grid related	1.43E-03	0.2	0.8289
UA	2.20E-02	Severe weather	9.12E-03	0.5	0.6096
		Extreme weather		1.0	0.4555
		Combined	5.06E-02	1.5	0.3711
				2.0	0.3138
				3.0	0.2363
				4.0	0.1874
				6.0	0.1335
				8.0	0.1055
				10.0	0.0881
				12.0	0.0758
				16.0	0.0594
				20.0	0.0487
				24.0	0.0410

a. Obtained from NUREG/CR-5994. Data from 84% of EDGs in use during 1988 - 1991. Includes test and unplanned demands. The FTLR rate was estimated using the data in the report (182 FTLR and FTR failures in 19520 FTLR demands) and characteristics of the baseline EPIX data. The EPIX data indicate 58 FTLR failures and 50 FTR failures, so the fraction of FTLR and FTR failures that are FTLR is 58/(58+50) = 0.537. Therefore, of the 182 FTLR and FTR failures, approximately 98 are FTLR and 84 are FTR. The FTLR rate is then (98+0.5)/19520 = 5.0E-3/h (assuming 1h/FTLR demand). For FTR, the EPIX data indicate 3.4h/demand. Therefore, the FTR rate is (84+0.5)/(19520*3.4) = 1.3E-3/h.

Appendix E

Plant-Specific Station Blackout Results Using Plant-Specific Loss of Offsite Power Frequencies

APPENDIX E

Plant-Specific Station Blackout Results

Using Plant-Specific Loss of Offsite Power Frequencies

The purpose of this appendix is to present the current core damage risk from SBO scenarios at U.S. commercial nuclear power plants based on plant-specific LOOP frequencies. Current is defined as a period centered about the year 2000. The industry average results of the SBO, LOOP, and total core damage frequencies (CDFs) are shown in Table E-1. All 103 operating commercial nuclear power plants are addressed. Risk is evaluated only for critical operation; risk from shutdown operation is not addressed in this report. Risk is defined as CDF. The standardized plant analysis risk (SPAR) models developed by the NRC for the 103 operating plants were used to evaluate plant-specific CDF risk.

Table E-1. Summary of plant-specific LOOP, SBO, and Total CDF results.

	Total CDF (1/rcry)	Total LOOP CDF (1/rcry)	LOOP Fract. CDF (1/rcry)	SBO Fract. CDF (1/rcry)	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability
Average	1.78E-05	3.27E-06	5.12E-07	2.76E-06	3.29E-02	1.22E-03	6.90E-02
Percent of CDF		18.4%	2.9%	15.5%			

E.1 Analysis of Plant-Specific SBO, LOOP, and Total CDF

The draft LOOP report presents plant-specific frequencies for the five LOOP categories in Appendix D of that report. The plant data from that table are summarized here in Table E-2. The frequencies shown here were used in the appropriate SPAR model to produce the results shown in Table E-3. Table E-4 shows the results of the uncertainty calculations for total CDF and SBO CDF.

Table E-2. Plant-specific LOOP category frequencies.

Plant	Plant Centered	Switchyard Centered	Grid Related	Severe Weather Related	Extreme Weather Related	Combined
Arkansas 1	2.31E-03	7.86E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Arkansas 2	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Beaver Valley 1	2.32E-03	7.99E-03	1.41E-02	2.89E-03	2.32E-03	2.97E-02
Beaver Valley 2	2.32E-03	7.95E-03	1.40E-02	2.88E-03	2.32E-03	2.95E-02
Braidwood 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Braidwood 2	2.31E-03	7.84E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Browns Ferry 2	2.31E-03	7.84E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Browns Ferry 3	2.31E-03	7.82E-03	1.36E-02	2.87E-03	2.32E-03	2.89E-02
Brunswick 1	2.31E-03	7.83E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Brunswick 2	2.31E-03	7.84E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Byron 1	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Byron 2	2.31E-03	7.83E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Callaway	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Calvert Cliffs 1	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Calvert Cliffs 2	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Catawba 1	2.31E-03	7.86E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Catawba 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Clinton 1	2.33E-03	8.12E-03	1.46E-02	2.90E-03	2.32E-03	3.02E-02
Columbia 2	2.32E-03	7.93E-03	1.40E-02	2.88E-03	2.32E-03	2.94E-02
Comanche Peak 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Comanche Peak 2	2.31E-03	7.86E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Cook 1	2.35E-03	8.29E-03	1.51E-02	2.93E-03	2.32E-03	3.10E-02
Cook 2	2.34E-03	8.21E-03	1.49E-02	2.92E-03	2.32E-03	3.07E-02
Cooper	2.32E-03	7.93E-03	1.40E-02	2.88E-03	2.32E-03	2.94E-02
Crystal River 3	2.32E-03	7.97E-03	1.41E-02	2.88E-03	2.32E-03	2.96E-02
Davis-Besse	2.33E-03	8.07E-03	1.44E-02	2.90E-03	6.96E-03	3.47E-02
Diablo Canyon 1	6.93E-03	7.86E-03	1.38E-02	2.87E-03	2.32E-03	3.37E-02
Diablo Canyon 2	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Dresden 2	2.31E-03	7.84E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Dresden 3	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Duane Arnold	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Farley 1	2.31E-03	7.90E-03	1.39E-02	2.88E-03	2.32E-03	2.93E-02
Farley 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Fermi 2	2.31E-03	7.90E-03	4.16E-02	2.88E-03	2.32E-03	5.70E-02
FitzPatrick	2.31E-03	7.85E-03	4.12E-02	2.87E-03	2.32E-03	5.65E-02
Fort Calhoun	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Ginna	2.31E-03	7.85E-03	4.11E-02	2.87E-03	2.32E-03	5.65E-02
Grand Gulf	2.31E-03	7.84E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02

Plant	Plant Centered	Switchyard Centered	Grid Related	Severe Weather Related	Extreme Weather Related	Combined
Harris	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Hatch 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Hatch 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Hope Creek	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Indian Point 2	2.33E-03	2.43E-02	4.34E-02	2.90E-03	2.32E-03	7.52E-02
Indian Point 3	2.31E-03	7.89E-03	4.15E-02	2.87E-03	2.32E-03	5.69E-02
Kewaunee	2.31E-03	7.91E-03	1.39E-02	2.88E-03	2.32E-03	2.93E-02
La Salle 1	2.32E-03	8.01E-03	1.42E-02	2.89E-03	2.32E-03	2.98E-02
La Salle 2	2.33E-03	8.11E-03	1.45E-02	2.90E-03	2.32E-03	3.02E-02
Limerick 1	2.31E-03	7.83E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Limerick 2	2.31E-03	7.83E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
McGuire 1	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
McGuire 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Millstone 2	2.33E-03	8.15E-03	1.47E-02	2.91E-03	2.32E-03	3.04E-02
Millstone 3	2.32E-03	8.03E-03	1.43E-02	2.89E-03	2.32E-03	2.99E-02
Monticello	2.31E-03	7.90E-03	1.39E-02	2.88E-03	2.32E-03	2.93E-02
Nine Mile Pt. 1	2.32E-03	7.94E-03	4.20E-02	2.88E-03	2.32E-03	5.75E-02
Nine Mile Pt. 2	2.31E-03	7.88E-03	4.14E-02	2.87E-03	2.32E-03	5.68E-02
North Anna 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
North Anna 2	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Oconee 1	2.32E-03	7.95E-03	1.40E-02	2.88E-03	2.32E-03	2.95E-02
Oconee 2	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Oconee 3	2.31E-03	7.91E-03	1.39E-02	2.88E-03	2.32E-03	2.93E-02
Oyster Creek	2.31E-03	2.35E-02	1.37E-02	2.87E-03	2.32E-03	4.48E-02
Palisades	2.32E-03	7.96E-03	1.41E-02	2.88E-03	2.32E-03	2.95E-02
Palo Verde 1	2.31E-03	7.84E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Palo Verde 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Palo Verde 3	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Peach Bottom 2	2.31E-03	7.82E-03	4.09E-02	2.87E-03	2.32E-03	5.62E-02
Peach Bottom 3	2.31E-03	7.83E-03	4.10E-02	2.87E-03	2.32E-03	5.63E-02
Perry	2.31E-03	7.87E-03	4.14E-02	2.87E-03	2.32E-03	5.68E-02
Pilgrim	2.31E-03	7.86E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Point Beach 1	2.32E-03	7.99E-03	1.42E-02	2.89E-03	2.32E-03	2.97E-02
Point Beach 2	2.32E-03	7.99E-03	1.41E-02	2.89E-03	2.32E-03	2.97E-02
Prairie Island 1	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Prairie Island 2	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Quad Cities 1	2.31E-03	7.90E-03	1.39E-02	2.88E-03	2.32E-03	2.93E-02
Quad Cities 2	2.32E-03	2.38E-02	1.40E-02	2.88E-03	2.32E-03	4.54E-02
River Bend	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Robinson 2	2.31E-03	7.83E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Salem 1	2.32E-03	2.40E-02	1.42E-02	2.89E-03	2.32E-03	4.57E-02
Salem 2	2.32E-03	7.95E-03	1.40E-02	2.88E-03	2.32E-03	2.95E-02
San Onofre 2	2.31E-03	7.89E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
San Onofre 3	2.31E-03	7.90E-03	1.39E-02	2.88E-03	2.32E-03	2.93E-02
Seabrook	2.31E-03	7.90E-03	1.39E-02	8.63E-03	2.32E-03	3.50E-02
Sequoyah 1	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Sequoyah 2	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
South Texas 1	2.31E-03	7.89E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02

Plant	Plant Centered	Switchyard Centered	Grid Related	Severe Weather Related	Extreme Weather Related	Combined
South Texas 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
St. Lucie 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
St. Lucie 2	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Summer	2.31E-03	7.89E-03	1.39E-02	2.87E-03	2.32E-03	2.93E-02
Surry 1	2.31E-03	7.88E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Surry 2	2.31E-03	7.86E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Susquehanna 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Susquehanna 2	2.31E-03	7.87E-03	1.38E-02	2.87E-03	2.32E-03	2.92E-02
Three Mile Isl 1	2.31E-03	2.36E-02	1.37E-02	2.87E-03	2.32E-03	4.48E-02
Turkey Point 3	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Turkey Point 4	2.31E-03	7.83E-03	1.37E-02	2.87E-03	2.32E-03	2.90E-02
Vermont Yankee	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Vogtle 1	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Vogtle 2	2.31E-03	7.85E-03	1.37E-02	2.87E-03	2.32E-03	2.91E-02
Waterford 3	2.31E-03	7.89E-03	1.39E-02	2.87E-03	2.32E-03	2.93E-02
Watts Bar 1	2.31E-03	7.86E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02
Wolf Creek	2.31E-03	7.86E-03	1.38E-02	2.87E-03	2.32E-03	2.91E-02

Note – All frequencies are per reactor critical year (rcry).

Table E-3. Plant-specific LOOP, SBO, and Total CDF results.

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Arkansas 1	4.15E-07	1.28E-08	4.03E-07	1.59E-05	2.53%	2.91E-02	2.96E-04	4.67E-02	BW (2-loop)
Arkansas 2	5.31E-07	1.42E-07	3.89E-07	1.51E-05	2.57%	2.92E-02	1.65E-03	8.06E-03	CE (2-loop)
Beaver Valley 1	1.04E-06	3.17E-09	1.04E-06	2.91E-05	3.57%	2.97E-02	1.37E-04	2.55E-01	WE (3-loop)
Beaver Valley 2	6.63E-07	2.55E-08	6.38E-07	3.00E-05	2.12%	2.95E-02	1.82E-04	1.19E-01	WE (3-loop)
Braidwood 1	3.86E-06	2.78E-07	3.58E-06	4.20E-05	8.52%	2.91E-02	3.51E-04	3.51E-01	WE (4-loop)
Braidwood 2	3.85E-06	2.77E-07	3.57E-06	4.20E-05	8.50%	2.90E-02	3.51E-04	3.50E-01	WE (4-loop)
Browns Ferry 2	2.01E-07	1.09E-07	9.22E-08	4.12E-07	22.35%	2.90E-02	2.81E-05	1.13E-01	BWR 3/4 (BWR with HPCI)
Browns Ferry 3	2.75E-07	1.83E-07	9.17E-08	4.86E-07	18.88%	2.89E-02	2.77E-05	1.14E-01	BWR 3/4 (BWR with HPCI)
Brunswick 1	8.81E-07	2.05E-07	6.76E-07	4.74E-06	14.26%	2.90E-02	2.00E-03	1.17E-02	BWR 3/4 (BWR with HPCI)
Brunswick 2	8.82E-07	2.05E-07	6.77E-07	4.74E-06	14.28%	2.90E-02	2.00E-03	1.17E-02	BWR 3/4 (BWR with HPCI)
Byron 1	3.94E-06	3.05E-07	3.64E-06	4.23E-05	8.59%	2.91E-02	3.51E-04	3.55E-01	WE (4-loop)
Byron 2	3.91E-06	3.03E-07	3.61E-06	4.23E-05	8.54%	2.90E-02	3.51E-04	3.55E-01	WE (4-loop)
Callaway	6.19E-06	9.42E-08	6.10E-06	1.10E-05	55.48%	2.91E-02	4.11E-03	5.11E-02	WE (4-loop)
Calvert Cliffs 1	1.23E-06	3.88E-08	1.19E-06	7.11E-05	1.67%	2.92E-02	3.66E-04	1.11E-01	CE (2-loop)
Calvert Cliffs 2	1.23E-06	3.88E-08	1.19E-06	7.11E-05	1.67%	2.92E-02	3.66E-04	1.11E-01	CE (2-loop)
Catawba 1	5.53E-06	2.84E-07	5.25E-06	9.60E-06	54.66%	2.91E-02	5.82E-04	3.10E-01	WE (4-loop)
Catawba 2	5.54E-06	2.85E-07	5.26E-06	9.61E-06	54.72%	2.92E-02	5.82E-04	3.10E-01	WE (4-loop)
Clinton 1	4.45E-06	1.92E-07	4.25E-06	4.72E-06	90.04%	3.02E-02	4.44E-03	3.17E-02	BWR 5/6 (BWR with HPCS)
Columbia 2	9.52E-06	3.23E-06	6.30E-06	1.07E-05	58.81%	2.94E-02	4.08E-03	5.24E-02	BWR 5/6 (BWR with HPCS)
Comanche Peak 1	1.58E-05	9.47E-08	1.57E-05	1.81E-05	86.62%	2.91E-02	3.97E-03	1.36E-01	WE (4-loop)
Comanche Peak 2	1.58E-05	9.48E-08	1.57E-05	1.81E-05	86.63%	2.91E-02	3.97E-03	1.36E-01	WE (4-loop)
Cook 1	6.84E-06	9.15E-08	6.75E-06	3.69E-05	18.26%	3.10E-02	1.92E-03	1.13E-01	WE (4-loop)
Cook 2	6.78E-06	9.05E-08	6.69E-06	3.69E-05	18.15%	3.07E-02	1.92E-03	1.14E-01	WE (4-loop)
Cooper	8.22E-06	9.64E-07	7.26E-06	1.56E-04	4.65%	2.94E-02	2.00E-03	1.23E-01	BWR 3/4 (BWR with HPCI)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Crystal River 3	9.97E-07	6.25E-07	3.72E-07	2.30E-05	1.61%	2.96E-02	2.20E-03	5.71E-03	BW (2-loop)
Davis-Besse	1.82E-06	1.48E-06	3.46E-07	1.87E-05	1.85%	3.47E-02	2.71E-03	3.68E-03	BW (2-loop)
Diablo Canyon 1	5.53E-07	5.63E-08	4.96E-07	4.86E-06	10.22%	3.37E-02	2.34E-04	6.29E-02	WE (4-loop)
Diablo Canyon 2	5.36E-07	4.97E-08	4.86E-07	4.84E-06	10.04%	2.91E-02	2.34E-04	7.14E-02	WE (4-loop)
Dresden 2	1.12E-07	7.53E-08	3.66E-08	7.93E-07	4.62%	2.90E-02	1.36E-05	9.26E-02	BWR 1/2/3 (BWR with IC)
Dresden 3	1.12E-07	7.56E-08	3.67E-08	7.93E-07	4.63%	2.92E-02	1.36E-05	9.25E-02	BWR 1/2/3 (BWR with IC)
Duane Arnold	5.81E-06	1.11E-07	5.70E-06	6.37E-06	89.50%	2.92E-02	5.14E-03	3.80E-02	BWR 3/4 (BWR with HPCI)
Farley 1	2.92E-06	7.01E-07	2.22E-06	8.58E-05	2.59%	2.93E-02	2.98E-04	2.54E-01	WE (3-loop)
Farley 2	2.90E-06	6.98E-07	2.21E-06	8.58E-05	2.57%	2.91E-02	2.98E-04	2.54E-01	WE (3-loop)
Fermi 2	1.19E-06	1.08E-06	1.11E-07	4.69E-06	2.37%	5.70E-02	2.09E-05	9.32E-02	BWR 3/4 (BWR with HPCI)
FitzPatrick	1.00E-06	5.82E-08	9.45E-07	2.51E-06	37.63%	5.65E-02	1.40E-04	1.19E-01	BWR 3/4 (BWR with HPCI)
Fort Calhoun	6.78E-06	5.18E-07	6.26E-06	1.36E-05	45.99%	2.92E-02	1.84E-03	1.17E-01	CE (2-loop)
Ginna	1.61E-05	4.91E-08	1.60E-05	2.25E-05	71.21%	5.65E-02	1.85E-03	1.53E-01	WE (2-loop)
Grand Gulf	7.60E-06	4.54E-06	3.06E-06	8.28E-06	36.90%	2.90E-02	4.95E-03	2.13E-02	BWR 5/6 (BWR with HPCS)
Harris	1.66E-05	9.80E-08	1.65E-05	4.29E-05	38.44%	2.92E-02	4.24E-03	1.33E-01	WE (3-loop)
Hatch 1	1.95E-06	1.17E-06	7.79E-07	1.10E-05	7.06%	2.91E-02	2.80E-04	9.57E-02	BWR 3/4 (BWR with HPCI)
Hatch 2	1.95E-06	1.17E-06	7.81E-07	1.10E-05	7.07%	2.91E-02	2.80E-04	9.57E-02	BWR 3/4 (BWR with HPCI)
Hope Creek	3.19E-06	1.06E-06	2.13E-06	8.78E-06	24.22%	2.92E-02	6.18E-04	1.18E-01	BWR 3/4 (BWR with HPCI)
Indian Point 2	3.04E-06	2.46E-06	5.85E-07	6.77E-06	8.65%	7.52E-02	3.02E-04	2.58E-02	WE (4-loop)
Indian Point 3	2.62E-06	5.76E-07	2.04E-06	5.80E-06	35.25%	5.69E-02	3.49E-04	1.03E-01	WE (4-loop)
Kewaunee	3.68E-06	2.53E-07	3.43E-06	6.51E-06	52.69%	2.93E-02	2.02E-03	5.79E-02	WE (2-loop)
La Salle 1	6.14E-07	2.36E-07	3.78E-07	1.57E-06	24.05%	2.98E-02	2.51E-04	5.05E-02	BWR 5/6 (BWR with HPCS)
La Salle 2	6.18E-07	2.37E-07	3.81E-07	1.57E-06	24.21%	3.02E-02	2.51E-04	5.03E-02	BWR 5/6 (BWR with HPCS)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Limerick 1	7.14E-07	4.28E-07	2.86E-07	1.67E-06	17.15%	2.90E-02	1.35E-04	7.31E-02	BWR 1/2/3 (BWR with IC)
Limerick 2	7.14E-07	4.28E-07	2.86E-07	1.67E-06	17.15%	2.90E-02	1.35E-04	7.31E-02	BWR 3/4 (BWR with HPCI)
McGuire 1	3.24E-06	1.66E-08	3.22E-06	4.89E-06	65.86%	2.92E-02	6.43E-04	1.72E-01	WE (4-loop)
McGuire 2	3.24E-06	1.66E-08	3.22E-06	4.89E-06	65.86%	2.92E-02	6.43E-04	1.72E-01	WE (4-loop)
Millstone 2	7.15E-07	2.16E-07	5.00E-07	1.66E-05	3.00%	3.04E-02	2.87E-04	5.73E-02	CE (2-loop)
Millstone 3	1.29E-06	2.00E-08	1.27E-06	6.23E-06	20.45%	2.99E-02	2.73E-04	1.56E-01	WE (4-loop)
Monticello	1.46E-06	2.78E-08	1.43E-06	5.94E-06	24.03%	2.93E-02	2.09E-03	2.33E-02	BWR 3/4 (BWR with HPCI)
Nine Mile Pt. 1	2.28E-06	7.08E-08	2.21E-06	3.75E-06	58.94%	5.75E-02	2.51E-03	1.53E-02	BWR 1/2/3 (BWR with IC)
Nine Mile Pt. 2	4.29E-06	2.39E-06	1.89E-06	1.59E-05	11.91%	5.68E-02	1.85E-03	1.80E-02	BWR 5/6 (BWR with HPCS)
North Anna 1	6.84E-07	9.46E-08	5.89E-07	7.81E-06	7.55%	2.91E-02	7.14E-05	2.84E-01	WE (3-loop)
North Anna 2	6.87E-07	9.51E-08	5.92E-07	7.81E-06	7.58%	2.92E-02	7.14E-05	2.84E-01	WE (3-loop)
Oconee 1	1.83E-06	1.26E-08	1.82E-06	5.69E-06	31.90%	2.95E-02	1.98E-03	3.11E-02	BW (2-loop)
Oconee 2	1.81E-06	1.24E-08	1.80E-06	5.68E-06	31.73%	2.92E-02	1.98E-03	3.12E-02	BW (2-loop)
Oconee 3	1.82E-06	1.25E-08	1.80E-06	5.68E-06	31.76%	2.93E-02	1.98E-03	3.10E-02	BW (2-loop)
Oyster Creek	1.86E-06	4.84E-07	1.38E-06	3.96E-06	34.72%	4.48E-02	1.84E-03	1.67E-02	BWR 1/2/3 (BWR with IC)
Palisades	6.99E-06	3.20E-07	6.67E-06	1.65E-05	40.44%	2.95E-02	1.94E-03	1.17E-01	CE (2-loop)
Palo Verde 1	2.54E-06	5.61E-07	1.98E-06	7.02E-06	28.22%	2.90E-02	8.98E-04	7.59E-02	CE (2-loop)
Palo Verde 2	2.55E-06	5.64E-07	1.99E-06	7.03E-06	28.31%	2.92E-02	8.98E-04	7.60E-02	CE (2-loop)
Palo Verde 3	2.54E-06	5.63E-07	1.98E-06	7.02E-06	28.21%	2.91E-02	8.98E-04	7.58E-02	CE (2-loop)
Peach Bottom 2	2.59E-06	2.98E-07	2.29E-06	8.97E-06	25.51%	5.62E-02	1.20E-03	3.39E-02	BWR 3/4 (BWR with HPCI)
Peach Bottom 3	2.59E-06	2.98E-07	2.29E-06	8.97E-06	25.52%	5.63E-02	1.20E-03	3.39E-02	BWR 3/4 (BWR with HPCI)
Perry	5.12E-07	2.42E-07	2.70E-07	3.77E-06	7.17%	5.68E-02	4.08E-03	1.17E-03	BWR 5/6 (BWR with HPCS)
Pilgrim	9.33E-08	5.45E-08	3.88E-08	1.89E-05	0.21%	2.91E-02	1.84E-03	7.25E-04	BWR 3/4 (BWR with HPCI)
Point Beach 1	2.64E-06	2.17E-06	4.68E-07	2.84E-05	1.65%	2.97E-02	3.51E-05	4.50E-01	WE (2-loop)

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
Point Beach 2	2.64E-06	2.17E-06	4.68E-07	2.84E-05	1.65%	2.97E-02	3.51E-05	4.50E-01	WE (2-loop)
Prairie Island 1	1.14E-06	2.64E-08	1.11E-06	5.12E-06	21.67%	2.92E-02	1.12E-04	3.40E-01	WE (2-loop)
Prairie Island 2	1.14E-06	2.64E-08	1.11E-06	5.12E-06	21.70%	2.92E-02	1.12E-04	3.40E-01	WE (2-loop)
Quad Cities 1	9.20E-07	8.82E-07	3.84E-08	1.71E-06	2.24%	2.93E-02	1.27E-05	1.03E-01	BWR 3/4 (BWR with HPCI)
Quad Cities 2	1.41E-06	1.36E-06	4.56E-08	2.20E-06	2.07%	4.54E-02	1.27E-05	7.91E-02	BWR 3/4 (BWR with HPCI)
River Bend	6.62E-06	1.49E-07	6.47E-06	6.92E-06	93.52%	2.92E-02	4.25E-03	5.22E-02	BWR 5/6 (BWR with HPCS)
Robinson 2	9.22E-06	1.82E-06	7.40E-06	1.30E-05	56.98%	2.90E-02	2.09E-03	1.22E-01	WE (3-loop)
Salem 1	3.58E-06	2.30E-07	3.35E-06	7.68E-06	43.71%	4.57E-02	7.66E-04	9.58E-02	WE (4-loop)
Salem 2	2.93E-06	1.48E-07	2.78E-06	7.02E-06	39.62%	2.95E-02	7.66E-04	1.23E-01	WE (4-loop)
San Onofre 2	2.64E-06	1.21E-06	1.43E-06	2.80E-05	5.09%	2.92E-02	2.49E-04	1.96E-01	CE (2-loop)
San Onofre 3	2.65E-06	1.21E-06	1.44E-06	2.80E-05	5.12%	2.93E-02	2.49E-04	1.97E-01	CE (2-loop)
Seabrook	1.19E-05	7.11E-08	1.19E-05	4.20E-05	28.29%	3.50E-02	2.66E-03	1.27E-01	WE (4-loop)
Sequoyah 1	1.77E-06	1.86E-08	1.75E-06	3.13E-05	5.59%	2.92E-02	4.82E-04	1.24E-01	WE (4-loop)
Sequoyah 2	1.77E-06	1.85E-08	1.75E-06	3.13E-05	5.59%	2.91E-02	4.82E-04	1.25E-01	WE (4-loop)
South Texas 1	9.62E-07	4.53E-08	9.17E-07	4.60E-06	19.93%	2.92E-02	2.57E-04	1.22E-01	WE (4-loop)
South Texas 2	9.60E-07	4.52E-08	9.15E-07	4.60E-06	19.89%	2.92E-02	2.57E-04	1.22E-01	WE (4-loop)
St. Lucie 1	1.05E-06	3.88E-08	1.01E-06	3.06E-05	3.29%	2.91E-02	2.92E-04	1.19E-01	CE (2-loop)
St. Lucie 2	9.15E-07	3.51E-07	5.63E-07	3.22E-05	1.75%	2.91E-02	2.92E-04	6.63E-02	CE (2-loop)
Summer	7.81E-06	4.71E-07	7.34E-06	1.29E-05	56.69%	2.93E-02	1.91E-03	1.31E-01	WE (3-loop)
Surry 1	1.20E-06	6.19E-07	5.78E-07	3.08E-06	18.78%	2.92E-02	1.88E-04	1.05E-01	WE (3-loop)
Surry 2	1.19E-06	6.17E-07	5.76E-07	3.08E-06	18.74%	2.91E-02	1.88E-04	1.05E-01	WE (3-loop)
Susquehanna 1	2.35E-06	2.12E-06	2.28E-07	3.34E-06	6.83%	2.91E-02	8.28E-05	9.46E-02	BWR 3/4 (BWR with HPCI)
Susquehanna 2	2.35E-06	2.12E-06	2.28E-07	3.34E-06	6.84%	2.92E-02	8.28E-05	9.45E-02	BWR 3/4 (BWR with HPCI)
Three Mile Isl 1	7.84E-07	6.15E-08	7.22E-07	6.58E-06	10.98%	4.48E-02	1.99E-03	8.10E-03	BW (2-loop)
Turkey Point 3	2.51E-06	1.99E-08	2.49E-06	2.69E-05	9.28%	2.91E-02	3.22E-04	2.67E-01	WE (3-loop)
Turkey Point 4	2.51E-06	1.99E-08	2.49E-06	2.69E-05	9.28%	2.90E-02	3.22E-04	2.67E-01	WE (3-loop)
Vermont Yankee	5.80E-07	5.79E-07	7.59E-10	2.51E-06	0.03%	2.91E-02	9.14E-06	2.86E-03	BWR 3/4 (BWR with

Plant Name	Total LOOP CDF (1/rcry)	LOOP CDF (1/rcry)	SBO CDF (1/rcry)	Total CDF (1/rcry)	SBO % of Total CDF	LOOP Frequency (1/rcry)	EPS Failure Probability	SBO Failure Probability	Plant Group
									HPCI)
Vogtle 1	2.25E-06	2.65E-07	1.99E-06	3.27E-05	6.08%	2.91E-02	2.91E-03	2.35E-02	WE (4-loop)
Vogtle 2	2.25E-06	2.65E-07	1.99E-06	3.27E-05	6.08%	2.91E-02	2.91E-03	2.35E-02	WE (4-loop)
Waterford 3	8.89E-06	3.64E-07	8.53E-06	1.76E-05	48.43%	2.93E-02	2.62E-03	1.11E-01	CE (2-loop)
Watts Bar 1	8.28E-07	2.49E-08	8.03E-07	3.17E-05	2.53%	2.91E-02	2.23E-04	1.24E-01	WE (4-loop)
Wolf Creek	7.20E-06	1.04E-06	6.17E-06	1.53E-05	40.27%	2.91E-02	4.11E-03	5.15E-02	WE (4-loop)

Table E-4. Plant-specific CDF and SBO uncertainty table.

	Total CDF (1/rcry)					SBO CDF (1/rcry)				
Plant	Point Estimate	5%	Median	Mean	95%	Point Estimate	5%	Median	Mean	95%
Arkansas 1	1.59E-05	7.12E-07	5.50E-06	1.59E-05	6.57E-05	4.03E-07	8.07E-09	1.33E-07	5.25E-07	2.02E-06
Arkansas 2	1.46E-05	4.22E-07	4.59E-06	1.53E-05	6.74E-05	3.87E-07	3.51E-09	9.88E-08	6.01E-07	2.10E-06
Beaver Valley 1	2.90E-05	5.52E-07	3.91E-06	3.07E-05	1.35E-04	1.04E-06	1.39E-08	3.61E-07	1.96E-06	8.21E-06
Beaver Valley 2	3.00E-05	7.58E-07	4.78E-06	2.85E-05	1.29E-04	6.32E-07	5.99E-09	1.76E-07	1.03E-06	4.49E-06
Braidwood 1	4.19E-05	3.01E-06	2.07E-05	4.51E-05	1.62E-04	3.56E-06	9.88E-08	1.58E-06	4.92E-06	1.86E-05
Braidwood 2	4.19E-05	3.01E-06	2.07E-05	4.51E-05	1.62E-04	3.55E-06	9.87E-08	1.58E-06	4.91E-06	1.86E-05
Browns Ferry 2	4.07E-07	2.37E-08	2.12E-07	6.19E-07	2.07E-06	9.00E-08	2.35E-10	2.26E-08	1.89E-07	7.37E-07
Browns Ferry 3	4.76E-07	2.48E-08	2.36E-07	6.76E-07	2.63E-06	8.84E-08	2.02E-10	2.20E-08	1.97E-07	7.08E-07
Brunswick 1	4.65E-06	5.26E-07	3.22E-06	4.95E-06	1.56E-05	6.40E-07	3.94E-09	1.20E-07	7.26E-07	2.94E-06
Brunswick 2	4.65E-06	5.26E-07	3.22E-06	4.96E-06	1.56E-05	6.41E-07	3.95E-09	1.20E-07	7.27E-07	2.95E-06
Byron 1	4.22E-05	2.96E-06	2.02E-05	4.18E-05	1.52E-04	3.57E-06	9.99E-08	1.57E-06	4.99E-06	1.99E-05
Byron 2	4.22E-05	2.95E-06	2.02E-05	4.18E-05	1.52E-04	3.55E-06	9.95E-08	1.57E-06	4.96E-06	1.98E-05
Callaway	1.12E-05	8.25E-07	5.63E-06	1.15E-05	3.98E-05	6.10E-06	1.08E-07	1.85E-06	5.96E-06	2.29E-05
Calvert Cliffs 1	7.11E-05	2.80E-06	2.72E-05	7.30E-05	2.87E-04	1.19E-06	4.89E-09	3.90E-07	1.47E-06	5.77E-06
Calvert Cliffs 2	7.11E-05	2.80E-06	2.72E-05	7.30E-05	2.87E-04	1.19E-06	4.89E-09	3.90E-07	1.47E-06	5.77E-06
Catawba 1	9.47E-06	1.22E-06	5.12E-06	9.65E-06	3.34E-05	5.19E-06	1.93E-08	1.32E-06	6.03E-06	2.49E-05
Catawba 2	9.48E-06	1.22E-06	5.13E-06	9.66E-06	3.35E-05	5.20E-06	1.93E-08	1.32E-06	6.04E-06	2.49E-05
Clinton 1	4.71E-06	1.37E-07	1.58E-06	5.94E-06	2.28E-05	4.25E-06	3.66E-08	1.13E-06	4.63E-06	2.03E-05
Columbia 2	1.01E-05	5.57E-07	4.64E-06	1.02E-05	3.75E-05	6.00E-06	6.20E-08	1.57E-06	6.47E-06	2.79E-05
Comanche Peak 1	1.79E-05	1.40E-06	8.13E-06	1.99E-05	7.34E-05	1.55E-05	2.76E-07	5.91E-06	1.73E-05	6.97E-05
Comanche Peak 2	1.80E-05	1.40E-06	8.14E-06	1.99E-05	7.35E-05	1.56E-05	2.77E-07	5.91E-06	1.73E-05	6.97E-05
Cook 1	3.68E-05	1.09E-06	1.01E-05	3.87E-05	1.49E-04	6.68E-06	5.69E-08	2.06E-06	7.57E-06	3.05E-05
Cook 2	3.68E-05	1.09E-06	1.01E-05	3.86E-05	1.49E-04	6.62E-06	5.63E-08	2.04E-06	7.50E-06	3.03E-05
Cooper	1.55E-04	2.93E-06	3.56E-05	1.64E-04	7.99E-04	6.91E-06	7.32E-08	2.34E-06	7.88E-06	3.27E-05

	Total CDF (1/rcry)					SBO CDF (1/rcry)				
Plant	Point Estimate	5%	Median	Mean	95%	Point Estimate	5%	Median	Mean	95%
Crystal River 3	2.30E-05	8.22E-07	6.11E-06	2.32E-05	8.47E-05	3.68E-07	6.96E-10	4.28E-08	4.41E-07	1.99E-06
Davis-Besse	1.87E-05	9.13E-07	7.09E-06	2.02E-05	8.06E-05	3.43E-07	1.38E-09	5.51E-08	3.92E-07	1.74E-06
Diablo Canyon 1	4.85E-06	3.87E-07	2.32E-06	4.94E-06	1.78E-05	4.96E-07	1.64E-08	1.81E-07	5.60E-07	2.14E-06
Diablo Canyon 2	4.83E-06	3.78E-07	2.29E-06	4.92E-06	1.77E-05	4.86E-07	1.49E-08	1.72E-07	5.49E-07	2.12E-06
Dresden 2	7.84E-07	2.75E-08	2.47E-07	8.32E-07	3.15E-06	3.49E-08	2.88E-11	5.22E-09	9.52E-08	3.13E-07
Dresden 3	7.84E-07	2.76E-08	2.47E-07	8.33E-07	3.15E-06	3.51E-08	2.89E-11	5.23E-09	9.55E-08	3.14E-07
Duane Arnold	6.11E-06	2.61E-07	2.24E-06	6.09E-06	2.44E-05	5.44E-06	4.99E-08	1.44E-06	5.50E-06	2.28E-05
Farley 1	8.52E-05	2.46E-06	2.00E-05	8.74E-05	3.73E-04	2.22E-06	1.86E-08	5.56E-07	2.95E-06	1.24E-05
Farley 2	8.51E-05	2.46E-06	2.00E-05	8.74E-05	3.73E-04	2.21E-06	1.86E-08	5.55E-07	2.94E-06	1.23E-05
Fermi 2	4.45E-06	1.57E-07	1.67E-06	4.60E-06	1.84E-05	1.03E-07	9.39E-11	1.44E-08	1.83E-07	6.28E-07
FitzPatrick	2.40E-06	2.15E-07	1.31E-06	2.41E-06	7.73E-06	8.46E-07	1.03E-08	2.68E-07	9.77E-07	3.65E-06
Fort Calhoun	1.35E-05	1.03E-06	6.54E-06	1.44E-05	5.13E-05	6.26E-06	5.27E-08	2.01E-06	7.27E-06	3.13E-05
Ginna	2.00E-05	2.43E-06	1.09E-05	2.21E-05	7.43E-05	1.36E-05	1.91E-07	4.29E-06	1.56E-05	6.82E-05
Grand Gulf	7.64E-06	3.72E-07	3.22E-06	8.19E-06	3.10E-05	2.87E-06	2.49E-08	6.33E-07	3.15E-06	1.36E-05
Harris	4.28E-05	3.96E-06	2.24E-05	4.45E-05	1.50E-04	1.65E-05	6.11E-07	7.26E-06	1.76E-05	7.16E-05
Hatch 1	1.08E-05	9.47E-07	5.87E-06	1.16E-05	3.93E-05	7.76E-07	1.19E-08	2.55E-07	9.54E-07	3.72E-06
Hatch 2	1.08E-05	9.48E-07	5.88E-06	1.16E-05	3.93E-05	7.77E-07	1.20E-08	2.56E-07	9.55E-07	3.72E-06
Hope Creek	8.71E-06	5.76E-07	4.36E-06	9.57E-06	3.64E-05	2.08E-06	3.51E-08	7.51E-07	3.04E-06	1.20E-05
Indian Point 2	6.74E-06	5.80E-07	3.09E-06	7.24E-06	2.47E-05	5.77E-07	1.89E-09	7.42E-08	6.17E-07	2.53E-06
Indian Point 3	5.64E-06	6.93E-07	3.28E-06	6.07E-06	1.93E-05	1.43E-06	5.84E-09	2.53E-07	1.74E-06	6.85E-06
Kewaunee	6.47E-06	9.11E-07	3.78E-06	6.49E-06	2.06E-05	3.41E-06	7.20E-08	1.07E-06	3.42E-06	1.44E-05
La Salle 1	1.54E-06	1.94E-07	9.78E-07	1.97E-06	6.29E-06	3.65E-07	3.43E-09	9.12E-08	6.22E-07	2.47E-06
La Salle 2	1.55E-06	1.94E-07	9.80E-07	1.98E-06	6.32E-06	3.68E-07	3.45E-09	9.22E-08	6.27E-07	2.51E-06
Limerick 1	1.66E-06	1.60E-07	9.40E-07	2.01E-06	6.76E-06	2.85E-07	7.26E-09	1.21E-07	3.99E-07	1.47E-06
Limerick 2	1.66E-06	1.60E-07	9.40E-07	2.01E-06	6.76E-06	2.85E-07	7.26E-09	1.21E-07	3.99E-07	1.47E-06
McGuire 1	4.86E-06	3.65E-07	2.26E-06	5.42E-06	1.95E-05	3.22E-06	9.48E-09	6.92E-07	3.70E-06	1.53E-05
McGuire 2	4.86E-06	3.65E-07	2.26E-06	5.41E-06	1.95E-05	3.22E-06	9.48E-09	6.92E-07	3.70E-06	1.53E-05

	Total CDF (1/rcry)					SBO CDF (1/rcry)				
Plant	Point Estimate	5%	Median	Mean	95%	Point Estimate	5%	Median	Mean	95%
Millstone 2	1.64E-05	2.53E-06	1.13E-05	1.91E-05	6.15E-05	4.96E-07	9.48E-09	1.70E-07	5.99E-07	2.44E-06
Millstone 3	5.97E-06	7.94E-07	3.60E-06	6.43E-06	2.09E-05	1.27E-06	4.39E-08	5.45E-07	1.47E-06	5.76E-06
Monticello	5.83E-06	5.25E-07	3.32E-06	5.99E-06	2.05E-05	1.39E-06	7.62E-09	2.91E-07	1.61E-06	6.45E-06
Nine Mile Pt. 1	3.67E-06	2.33E-07	1.87E-06	3.92E-06	1.36E-05	2.15E-06	4.31E-08	7.10E-07	2.43E-06	9.44E-06
Nine Mile Pt. 2	1.52E-05	1.14E-06	8.10E-06	1.69E-05	5.78E-05	1.84E-06	3.91E-08	5.93E-07	1.98E-06	7.72E-06
North Anna 1	7.80E-06	3.83E-07	2.17E-06	7.58E-06	2.67E-05	5.88E-07	1.41E-08	2.50E-07	8.39E-07	3.35E-06
North Anna 2	7.80E-06	3.83E-07	2.17E-06	7.59E-06	2.67E-05	5.91E-07	1.42E-08	2.51E-07	8.43E-07	3.37E-06
Oconee 1	5.68E-06	3.24E-07	2.63E-06	5.74E-06	2.05E-05	1.82E-06	1.78E-08	4.18E-07	1.87E-06	7.55E-06
Oconee 2	5.66E-06	3.23E-07	2.62E-06	5.72E-06	2.05E-05	1.80E-06	1.77E-08	4.14E-07	1.85E-06	7.46E-06
Oconee 3	5.67E-06	3.24E-07	2.63E-06	5.73E-06	2.05E-05	1.81E-06	1.77E-08	4.15E-07	1.86E-06	7.49E-06
Oyster Creek	3.96E-06	3.40E-07	1.99E-06	4.23E-06	1.33E-05	1.38E-06	1.12E-08	2.89E-07	1.62E-06	6.43E-06
Palisades	1.65E-05	1.68E-06	1.06E-05	1.74E-05	5.55E-05	6.67E-06	8.15E-08	2.11E-06	7.56E-06	3.34E-05
Palo Verde 1	6.98E-06	6.45E-07	3.99E-06	8.88E-06	3.10E-05	1.96E-06	3.22E-09	3.15E-07	2.35E-06	1.11E-05
Palo Verde 2	7.00E-06	6.47E-07	3.99E-06	8.89E-06	3.10E-05	1.97E-06	3.23E-09	3.17E-07	2.36E-06	1.12E-05
Palo Verde 3	6.99E-06	6.46E-07	3.99E-06	8.89E-06	3.10E-05	1.96E-06	3.23E-09	3.16E-07	2.35E-06	1.11E-05
Peach Bottom 2	8.89E-06	4.29E-07	3.63E-06	9.25E-06	3.55E-05	2.22E-06	4.84E-09	3.18E-07	2.42E-06	1.04E-05
Peach Bottom 3	8.89E-06	4.29E-07	3.63E-06	9.26E-06	3.56E-05	2.22E-06	4.85E-09	3.18E-07	2.43E-06	1.04E-05
Perry	3.73E-06	9.21E-08	9.80E-07	3.94E-06	1.69E-05	2.60E-07	2.41E-09	6.43E-08	4.21E-07	1.69E-06
Pilgrim	1.89E-05	3.71E-07	4.43E-06	1.86E-05	8.08E-05	3.63E-08	2.31E-11	4.13E-09	7.27E-08	2.88E-07
Point Beach 1	2.83E-05	1.98E-06	1.37E-05	2.78E-05	1.01E-04	4.67E-07	2.91E-09	1.07E-07	5.69E-07	2.30E-06
Point Beach 2	2.83E-05	1.98E-06	1.37E-05	2.78E-05	1.01E-04	4.67E-07	2.91E-09	1.07E-07	5.69E-07	2.30E-06
Prairie Island 1	5.10E-06	1.00E-06	3.63E-06	5.28E-06	1.46E-05	1.11E-06	3.35E-08	4.90E-07	1.22E-06	4.56E-06
Prairie Island 2	5.10E-06	1.01E-06	3.63E-06	5.28E-06	1.47E-05	1.11E-06	3.35E-08	4.91E-07	1.22E-06	4.57E-06
Quad Cities 1	1.64E-06	4.31E-08	5.46E-07	1.66E-06	6.75E-06	2.63E-08	2.12E-11	4.09E-09	7.91E-08	2.56E-07
Quad Cities 2	2.10E-06	4.90E-08	6.38E-07	2.15E-06	8.95E-06	3.11E-08	2.43E-11	5.01E-09	9.74E-08	3.33E-07
River Bend	6.90E-06	2.49E-07	2.75E-06	8.01E-06	3.12E-05	6.46E-06	1.34E-07	2.35E-06	6.99E-06	2.83E-05
Robinson 2	1.28E-05	1.38E-06	7.16E-06	1.35E-05	4.48E-05	7.33E-06	1.28E-07	2.48E-06	8.48E-06	3.49E-05

	Total CDF (1/rcry)					SBO CDF (1/rcry)				
Plant	Point Estimate	5%	Median	Mean	95%	Point Estimate	5%	Median	Mean	95%
Salem 1	7.59E-06	7.28E-07	4.00E-06	8.53E-06	3.02E-05	3.28E-06	1.68E-08	7.75E-07	3.92E-06	1.61E-05
Salem 2	6.95E-06	6.86E-07	3.69E-06	7.74E-06	2.78E-05	2.72E-06	1.29E-08	6.01E-07	3.22E-06	1.30E-05
San Onofre 2	2.79E-05	2.46E-06	1.23E-05	2.90E-05	9.83E-05	1.41E-06	8.81E-09	3.78E-07	2.24E-06	1.07E-05
San Onofre 3	2.80E-05	2.46E-06	1.23E-05	2.91E-05	9.84E-05	1.42E-06	8.82E-09	3.78E-07	2.24E-06	1.07E-05
Seabrook	4.18E-05	1.89E-06	1.29E-05	4.23E-05	1.64E-04	1.17E-05	2.51E-07	4.50E-06	1.30E-05	4.99E-05
Sequoyah 1	3.12E-05	7.34E-07	5.65E-06	3.04E-05	1.21E-04	1.73E-06	2.79E-08	5.98E-07	2.27E-06	9.36E-06
Sequoyah 2	3.12E-05	7.33E-07	5.65E-06	3.04E-05	1.21E-04	1.73E-06	2.77E-08	5.96E-07	2.26E-06	9.33E-06
South Texas 1	4.81E-06	3.14E-07	2.28E-06	5.54E-06	1.93E-05	9.07E-07	1.55E-08	3.11E-07	1.08E-06	4.15E-06
South Texas 2	4.81E-06	3.14E-07	2.28E-06	5.54E-06	1.93E-05	9.06E-07	1.55E-08	3.10E-07	1.07E-06	4.13E-06
St. Lucie 1	2.96E-05	1.17E-06	1.15E-05	2.97E-05	1.17E-04	1.00E-06	8.01E-09	2.75E-07	1.49E-06	6.89E-06
St. Lucie 2	3.11E-05	1.41E-06	1.34E-05	3.03E-05	1.18E-04	5.58E-07	4.44E-09	1.39E-07	9.03E-07	3.69E-06
Summer	1.29E-05	1.10E-06	6.46E-06	1.33E-05	4.79E-05	7.27E-06	1.33E-07	2.51E-06	8.02E-06	3.17E-05
Surry 1	3.05E-06	3.32E-07	1.77E-06	3.44E-06	1.15E-05	5.72E-07	1.22E-09	1.05E-07	9.09E-07	3.80E-06
Surry 2	3.05E-06	3.32E-07	1.77E-06	3.44E-06	1.15E-05	5.70E-07	1.21E-09	1.05E-07	9.07E-07	3.79E-06
Susquehanna 1	3.29E-06	1.49E-07	1.29E-06	4.32E-06	1.56E-05	2.15E-07	1.46E-09	4.80E-08	2.34E-07	1.02E-06
Susquehanna 2	3.29E-06	1.50E-07	1.29E-06	4.32E-06	1.56E-05	2.15E-07	1.46E-09	4.81E-08	2.35E-07	1.02E-06
Three Mile Isl 1	6.56E-06	4.31E-07	3.04E-06	6.97E-06	2.56E-05	7.21E-07	8.84E-09	2.09E-07	9.56E-07	3.89E-06
Turkey Point 3	2.69E-05	1.24E-06	7.96E-06	2.58E-05	1.05E-04	2.47E-06	5.28E-08	9.14E-07	2.65E-06	1.05E-05
Turkey Point 4	2.68E-05	1.24E-06	7.96E-06	2.58E-05	1.05E-04	2.46E-06	5.27E-08	9.12E-07	2.65E-06	1.05E-05
Vermont Yankee	2.50E-06	2.47E-07	1.34E-06	2.55E-06	8.61E-06	6.35E-10	1.65E-12	9.93E-11	8.74E-10	3.60E-09
Vogtle 1	3.27E-05	1.36E-06	6.53E-06	3.19E-05	1.32E-04	1.99E-06	1.58E-08	4.11E-07	2.22E-06	8.26E-06
Vogtle 2	3.27E-05	1.36E-06	6.53E-06	3.19E-05	1.32E-04	1.99E-06	1.58E-08	4.11E-07	2.22E-06	8.25E-06
Waterford 3	1.76E-05	1.14E-06	8.40E-06	1.87E-05	6.60E-05	8.53E-06	1.06E-07	2.99E-06	9.20E-06	3.81E-05
Watts Bar 1	3.17E-05	8.42E-07	6.14E-06	3.24E-05	1.32E-04	7.95E-07	8.89E-09	2.42E-07	1.30E-06	5.41E-06
Wolf Creek	1.55E-05	1.23E-06	8.18E-06	1.57E-05	5.43E-05	6.13E-06	1.08E-07	1.80E-06	6.17E-06	2.62E-05