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LICENSING TOPICAL REPORT

**GUIDANCE FOR SEPARATION OF LOSS OF OFFSITE
POWER FROM LARGE BREAK LOCA**

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LIST OF ACRONYMS

Term	Definition
AC	Alternating Current
AOO	Anticipated Operational Occurrence
ARI	Alternate Rod Insertion
ATWS	Anticipated Transient without Scram
B&W	Babcock and Wilcox
BOP	Balance of Plant
BWR	Boiling Water Reactor
BWROG	BWR Owners' Group
CCDP	Conditional Core Damage Probability
CCR	Combined Change Request
CDF	Core Damage Frequency
CFR	Code Of Federal Regulations
CLERP	Conditional Large Early Release Probability
CPR	Critical Power Ratio
CRD	Control Rod Drive
CSS	Containment Spray System
CST	Condensate Storage Tank
DBA	Design Basis Accident
DC	Direct Current
DG	Diesel Generator
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPG	Emergency Procedure Guidelines
EPU	Extended Power Uprate
FSAR	Final Safety Analysis Report
GDC	General Design Criteria

Term	Definition
GE	General Electric Company
HPCI	High Pressure Coolant Injection System
HPCS	High Pressure Core Spray
IORV	Inadvertent Open Relief Valve
IRIR	Integrated Risk Informed Regulation
ISLOCA	Interfacing Systems Loss of Coolant Accident
LBLOCA	Large-Break Loss Of Coolant Accident
LBLOCA/LOOP	LBLOCA with a Concurrent Loss of Offsite Power
LERF	Large Early Release Frequency
LHGR	Linear Heat Generation Rate
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LOSW	Loss of Service Water
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
LTR	Licensing Topical Report
MAAP	Modular Accident Analysis Program
MBLOCA	Medium Break Loss of Coolant Accident
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
OLTP	Original Licensed Thermal Power
PCS	Power Conversion System
PCT	Peak Cladding Temperature
PRA	Probabilistic Risk Assessment
PSS	Pressure Suppression System
PWR	Pressurized Water Reactor
RCIC	Reactor Core Isolation Cooling System

Term	Definition
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RITS	Risk Informed Technical Specification
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SBLOCA	Small Break Loss of Coolant Accident
SBO	Station Blackout
SLC	Standby Liquid Control
SORV	Stuck Open Relief Valve
SP	Suppression Pool
SPC	Suppression Pool Cooling
SRM	(NRC) Staff Requirements Memorandum
SRV	Safety Relief Valve
TBCCW	Turbine Building Closed Cooling Water
TMI	Three Mile Island
UHS	Ultimate Heat Sink

CROSS-REFERENCE OF LTR SECTIONS TO PREVIOUS LTR

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4. Process for Making LBLOCA/LOOP Changes	Primarily a New Section, also replaces 6.1, 9.1, 9.2
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Appendix B: Thermal-hydraulic Analysis	Appendix B, modified as needed
Appendix C: Generic PRA Evaluation for LBLOCA/LOOP Exemption	Appendix C, modified as needed
Appendix D: Response to RAIs	New Section
Appendix E: Example Calculation of Plant-specific Probability of Conditional LOOP Given a LOCA	New Section

EXECUTIVE SUMMARY

Beginning with the publication of Reactor Safety Study (WASH-1400) in 1975, the Nuclear Regulatory Commission (NRC) has endeavored to incorporate risk insights into the regulatory process. Today, risk insights, using Probabilistic Risk Assessment (PRA) models of power plants, form the cornerstone of NRC's Reactor Oversight Process and govern the routine operation of power plants, via the Maintenance Rule (10 CFR 50.65). In SECY-98-300 (Reference 1), the Staff proposed a framework for changing the current regulatory requirements using similar risk-informed processes. This Licensing Topical Report (LTR) is the culmination of extensive dialogue between the NRC and the Boiling Water Reactor Owners' Group (BWROG) to apply that risk-informed process to the current regulatory requirements of 10 CFR 50.46 and 10 CFR Part 50, Appendix A – General Design Criterion 35. Specifically, this document provides guidance for justifying the removal of the current requirement to postulate a loss-of-offsite power (LOOP) concurrent with the design basis accident (DBA) large break loss-of-coolant accident (LBLOCA).

Pending rulemaking to accomplish this goal, the Staff has stated that individual licensees may submit requests for exemption, pursuant to 10 CFR 50.12, to these current requirements. The purpose of this document is to provide guidance for developing adequate technical and regulatory justification for the NRC to approve such an exemption to the regulations for a requesting BWR licensee. To accomplish this, the BWROG has:

- Identified the specific regulations for which the exemption is applicable and the basis for granting the exemption. It is understood that not all the regulations that contain the coincident LOOP requirement are covered by this exemption.
- Identified the specific design changes facilitated by the exemption. These changes are defined at a conceptual design level with some detailed design information provided where needed for clarity. It is anticipated that individual licensees will limit the scope of the exemption request to those changes specified in this report. However, an individual licensee may request additional changes on a plant-specific basis as long as adequate justification is provided.
- Developed a 24-step process that individual licensees can use to prepare a risk-informed exemption request. The process includes thermal-hydraulic analysis, qualitative risk evaluation, quantitative risk evaluation where needed, and deterministic studies required by RG 1.174.
- Completed a generic example risk analysis (Appendix C) that demonstrates: 1) the probability of a large break LOCA in combination with a LOOP is consistent with the Regulatory Guide 1.174 (Reference 4) threshold for such regulatory

changes (i.e., less than $1.0E-6$); and, 2) there is an overall risk balance for BWRs by implementing the changes. It is recognized that the analysis used as an example in this report is generic to various BWR product lines; however, key parameters are identified so a licensee can modify this generic analysis, as necessary, by using the 24-step process to make it plant-specific for use in the licensee's submittal.

- Completed a "defense-in-depth" evaluation, as well as a demonstration of the "safety margins" following implementation of the changes identified in this report, which show that there is reasonable certainty that no gross fuel failure will occur and that the reactor coolant pressure boundary, as well as the containment barriers, remain intact, even if the assumed LOOP/LBLOCA were to occur. The deterministic analysis is generic to various BWR product lines. However, key parameters are identified so a licensee can modify the generic analysis as necessary to make it plant-specific for use in the licensee's submittal.

The goal of this guidance document is to provide a method for developing an exemption request that will result in a more risk-balanced plant design and improve overall plant safety by the elimination of this unnecessary and burdensome regulatory requirement.

The BWROG initially submitted this topical report in April 2004 using the generic plant risk analysis as the basis for the exemption request, with essentially no requirement for plant-specific risk evaluation or deterministic thermal-hydraulic analysis to be performed as part of the individual licensee's exemption request. In subsequent discussions with the NRC, the BWROG has agreed to revise the topical report such that the revised report becomes a guidance document for the individual licensees to prepare the exemption request. Using this revised report as the guide (See Section 4.0), individual licensees will prepare their own exemption requests, which will include any required plant-specific risk assessment as well as any required deterministic analyses. The generic risk assessment prepared as part of the original topical report has been included as a sample analyses to this LTR.

SECTIONS

1.0 INTRODUCTION

In Commission Paper SECY-98-300, "Options for Risk-Informed Revisions to 10 CFR Part 50 – 'Domestic Licensing of Production and Utilization Facilities'," dated December 23, 1998 (Reference 1), the NRC Staff recommended that consideration be given to changing some of the individual requirements of 10 CFR Part 50 based upon the insights that had been gained from Probabilistic Risk Assessments (PRA) of nuclear power plants. This proposal was referred to as "Option 3" in SECY-98-300. The pilot application chosen for Option 3 was 10 CFR 50.46, the specific requirements for Emergency Core Cooling Systems (ECCS).

In its Staff Requirements Memorandum (SRM) dated March 31, 2003 (Reference 2), the NRC Commissioners directed the Staff to proceed with rulemaking, under the Option 3 framework, to risk-inform the ECCS functional reliability requirements in 10 CFR Part 50, Appendix A - General Design Criterion 35, by revising the current requirements and removing the consideration of a large break loss-of-coolant accident (LBLOCA) coincident with a loss-of-offsite power (LOOP).

The NRC staff was directed, as allowed by 10 CFR 50.12, to consider a licensee's request for exemptions to these requirements. The Staff's review of such exemption(s) will facilitate the rulemaking process, similar to the approach utilized in development of the rule for Special Treatments, 10 CFR 50.69, referred to as Option 2. The BWROG has met with the Staff on many occasions to discuss the technical approach that would form the basis for such an exemption. The result of these meetings was the development of this Licensing Topical Report (LTR).

This LTR provides the technical and regulatory basis for an exemption request and licensee guidance for implementation. It should be noted that this LTR makes use of other published reports, both NRC and Industry, for its justification of several important assumptions made in this study, e.g., LBLOCA frequency and consequential/delayed LOOP.

This LTR was initially submitted to the NRC in April 2004. It was intended that the previous version of the LTR could be referenced by any BWR licensee in a specific 10 CFR 50.12 exemption request without the need to perform extensive plant-specific risk evaluation or deterministic thermal-hydraulic analysis as part of the individual licensee's exemption request. In subsequent discussions with the NRC, the BWROG has agreed to revise the topical report such that the revised report becomes a guidance document for the individual licensees to prepare the exemption request. Using this revised report as the guide (See Section 4.0), individual licensees will prepare their own exemption requests, which will include any required plant-specific risk assessment as well as any required deterministic analyses. The generic risk assessment prepared as part of the original topical report has been included as a sample analysis

to this LTR. This approach should help streamline NRC review of the individual submittals and provide the supporting framework for the proposed rulemaking outlined in Reference 2.

2.0 TECHNICAL APPROACH

2.1 Background

The NRC Staff position, as taken from Reference 3 (Section 3.1.2, "ECCS-Related Design Basis Changes"), is as follows:

For applications that would seek to change the design basis for the ECCS (e.g., to remove an accident from the ECCS design basis analyses), the resulting change in CDF and LERF must also meet the criteria from the framework for risk-informing 10 CFR Part 50 and Regulatory Guide 1.174 as described in Section 3.1. The resulting changes in CDF and LERF are determined by assuming that the plant can no longer respond to this particular accident (i.e., the subject accident is assumed to lead directly to core damage). As an example, a large LOCA with a coincident LOOP could be removed from the design basis if the frequency of that combination of events from all possible contributors (random pipe breaks from all known mechanisms, seismic events, heavy load drops, etc.) were to be assumed to lead directly to core damage, but still meet the framework and RG 1.174 criteria. This could allow, for example, an increase in the diesel generator start time. The full extent of plant changes to be allowed, with respect to both design basis changes and design or operational changes, would need to be established by the staff.

Regulatory Guide 1.174, Section 2 (Reference 4) provides the key principles of risk-informed decision-making when making changes to the licensing basis:

- The proposed change meets current regulations unless it is explicitly related to a requested exemption or rule change.
- The proposed change is consistent with defense-in-depth philosophy.
- The proposed change maintains sufficient safety margins.
- When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.*
- The impact of the proposed change should be monitored using performance measurement strategies.

* For purposes of RG 1.174, a proposed licensing basis change that meets the acceptance guidelines discussed in Section 2.2.4 of the RG is considered to have met the intent of the policy statement.

2.2 BWROG Approach

With the publication of Reference 3, as highlighted above, the BWROG began developing its approach for evaluating the feasibility of implementing this change using the RG 1.174 template. This approach was developed in stages over the last few years. Public meetings were held with the Staff to discuss the conceptual approach as it was developed and to define the key points for detailed evaluation in the proposed LTR. As noted earlier, the LTR serves a dual purpose. One is to assist licensees in requesting exemption from the existing regulatory requirements, pursuant to 10 CFR 50.12; and, the other is to offer insights to assist the Staff in their preparation of rulemaking to revise the existing regulations, as requested by Reference 2.

The cornerstone of the approach is the recognition that the LBLOCA/LOOP combination is not completely removed from the licensing basis with the proposed change in regulation, but is redefined from a design basis event to a beyond design basis accident, for which some mitigation capability must be assured. Also, continued compliance with 10 CFR 50.46 (and all other relevant regulations) must be demonstrated after any plant changes to the revised design basis (LBLOCA with offsite power available, and Small Break LOCAs, both with and without LOOP).

The following discusses the overall philosophy and rationale for the approach taken in this study. The details of this approach follow in the subsequent sections of this LTR.

Key questions to help focus the approach were addressed, including:

Definition of a "Large" Break LOCA

The existing regulations cover a spectrum of break sizes from a very small leak up to the assumed double-ended guillotine break of the largest pipe in the reactor coolant pressure boundary. Underlying this spectrum of break sizes is a corresponding expected frequency of occurrence, with the frequency being inversely proportional to the break size - the larger break areas being significantly less likely to occur than small cracks or leaks. So, based upon likelihood of occurrence, some portion of the break spectrum can be relegated to beyond design basis accident space. While the specific value for the pipe size that demarcates a "large break" in the total break spectrum is being debated in other forums, it is not essential to this LTR. In the BWROG approach any combination of break size (frequency), combined with the probability of LOOP, of less than the RG 1.174 criterion for "small increase" in core damage frequency (CDF) of $1.0\text{E-}6$ per reactor year, is acceptable.

The thermal-hydraulic (T/H) analysis demonstrated mitigation of a double-ended guillotine break of the largest pipe in the Reactor Recirculation system; this is applied consistently for all of the seven options. At the time the original LTR was written in April 2004, the break size of 10 inches or greater corresponded in the published works to a frequency of $1.0\text{E-}4$ /year, which when

coupled with the conditional LOOP given LOCA probability of $1.0\text{E-}2$, gave the target input probability of $1.0\text{E-}6$ for LBLOCA/LOOP.

This revised topical report utilizes the more recent references for LOCA frequencies, combined with plant-specific conditional LOOP probabilities given a LOCA, to determine the break sizes that will be redefined in the licensing basis. Based on the LOCA frequency values in NUREG-1829, certain plants may be able to justify exemption for break sizes of 7" diameter and above.

Application of the Risk Metrics in RG 1.174

The BWROG believes that the changes afforded by this re-definition of the design basis can lead to an improvement in overall reactor safety, i.e., that the incremental increase in core damage frequency from relaxing LBLOCA/LOOP mitigation capability would be offset (in whole or in part) by the improvements in plant response capability to more-likely, events. This is consistent with RG 1.174 guidelines for combined change requests (CCRs).

In the BWROG approach, by definition, the LBLOCA/LOOP combination would be assumed to "go straight to core damage," i.e., without a success path in the PRA. This case would set the base PRA CDF and would be shown to meet the criteria of RG 1.174. Then, the proposed changes in plant design and operation would be shown to, both individually and in combination, meet the criteria of RG 1.174. The generic evaluation of Appendix C shows a decrease in risk or risk neutrality for all the changes except one. It is expected that licensees will have similar results from their plant-specific analyses.

In the generic example application provided in Appendix C, using the "risk-balance" approach, the RG 1.174 criterion for core damage frequency of $1.0\text{E-}6$ per reactor year for being a "small risk increase" is assigned to the LBLOCA/LOOP event frequency and is the target improvement in reliability needed to offset this increase. (If the LBLOCA/LOOP frequency is greater than $1.0\text{E-}6$ per reactor year, this exemption is not permitted). The CDF value used was compared with other recently published studies (References 2, 3, 8, and 10), and is generally consistent with the results of those studies. Appendix C of this LTR discusses this more fully.

Large Early Release Frequency (LERF) contribution from LBLOCA with injection failure sequences is small at BWRs. A typical number for the conditional probability of LERF given a LBLOCA with loss-of-injection is about 0.01 (Reference 12)*. This small fraction is a result of several factors, in particular that vessel failure occurs at low RPV pressure and there is water on the drywell floor at the time of vessel failure. None of these factors is affected by the proposed separation of LBLOCA and LOOP. This leads to a maximum LERF increase of $1.0\text{E-}8$ per year for the generic example, which is about an order of magnitude below the RG 1.174 guidelines.

* Large break LOCA with failure to scram has a significantly higher LERF fraction, but because of the small contribution of ATWS in LBLOCA events, the overall conditional LERF probability remains 0.01.

In Step 2 of the process delineated in Section 4, individual licensees will calculate plant-specific values for this LBLOCA/LOOP frequency, which will be assumed to be the core damage frequency for this event, instead of the $1.0\text{E-}6$ per reactor assumed in the generic example. Individual licensees will be required to evaluate plant-specific LERF values also. The reference provided in Step 2 for the frequency of LBLOCA (Reference 13) is more recent than those used in the example application provided in Appendix C.

Conditional Probability of a LOOP Event Given a LBLOCA

1. A loss of offsite power following a LBLOCA can occur in one of three ways:
2. Reactor trip and the subsequent loss of generation can cause instability in the offsite grid.
3. The transfer of the power source for plant loads, from the main generator to power from offsite through an auxiliary transformer, can fail following a plant trip.
4. The loading of safety loads onto the emergency buses, once the buses are powered from offsite, can cause instability in the offsite grid or cause plant level equipment failures that result in loss of offsite power.

The conditional probability of LOOP given LBLOCA can be determined by examining historical data or by fault tree modeling of the component failures that can lead to a loss of offsite power.

Double Sequencing

There is one subset of LOOP given LOCA events that has been identified as a contributor to the problem of double sequencing. Double sequencing refers to an unintended sequence of operations at a nuclear power plant during which safety and accident mitigation loads automatically start, shutdown and restart in rapid succession when called on to operate. This occurs when, for some combination of reasons, safety bus voltages fall below acceptable levels after the plant is shut down and mitigation loads are started. The buses must be isolated and then re-powered from diesel generators or some alternate offsite source. Following this, shutdown and mitigation loads can be restarted. This series of actions is called double sequencing.

Double sequencing would most likely occur if there were a concurrent LOCA, with its associated plant trip, a prior stressed transmission grid condition. Based upon published studies by EPRI and NRC, the BWROG does not believe that such double sequencing events create greater consequences than assumed in this LTR for both PRA and T/H evaluations. To ensure that the problem is bounded, it is assumed that all delayed LBLOCA/ LOOP sequences go to core damage in the PRA evaluation. In the T/H evaluations, the impact is encompassed in the overall

delay time for injection. This approach is very conservative and makes the double sequencing issue a moot point from the core damage risk point of view.

Identification of the Implementation Options

With such a fundamental change in the design basis, concerns were expressed that implementation could be too open-ended. The approach was to focus only on the largest break sizes that drive the design requirements on the mitigating equipment. Thus, in the approach described above, the restrictive design requirements that created unnecessary burden should be identified, and then those requirements should be relaxed only to the point where the burden was eliminated. This relaxation should still: 1) meet the revised design basis, and 2) show acceptable mitigation for the new beyond design basis event.

To accomplish the above, surveys were sent out to the BWR licensees to identify and rank the possible design requirements that could be revised with the proposed change in licensing basis. The survey results were screened for feasibility. Section 2.4 of this LTR is the final result of the survey. One of the results of this survey is that some items can be mutually exclusive, as discussed further in the thermal-hydraulic analysis in Section 2.5 and Section 4, Step 5.

Implementation Guide

In Section 4, this LTR provides an implementation guide for the individual utilities to prepare their own exemption requests. This includes guidance for carrying out any required plant-specific risk assessments, as well as any required plant-specific deterministic analyses. Appendix C demonstrates the feasibility of the changes generically through probabilistic risk assessments. Section 3.0 contains the deterministic evaluations performed generically for the BWR fleet. Appendix B contains the thermal-hydraulic analyses performed for the BWR fleet. This information should be sufficient for individual licensees to prepare plant-specific exemption requests.

Application of the "defense-in-depth" and "safety margin" philosophies of RG 1.174

As discussed earlier, some measure of mitigation capability should be retained for the new beyond design basis event of the LBLOCA/LOOP, assuming the other plant changes were implemented. The BWROG chose to use a classical, deterministic definition of defense-in-depth for fission product barriers for simplicity. Because LBLOCA/LOOP is now considered a beyond design basis accident, some level of core damage can be tolerated. In addition, by definition, a LOCA is a breach of the fission product barrier of the reactor coolant pressure boundary. Thus, to ensure that the next fission product barrier of the containment was not challenged by this new event, it was decided that retaining the core material inside the reactor vessel would be used as the acceptance criterion for mitigation, i.e., maintaining the fuel in a "coolable geometry" was

chosen to ensure that the core material was retained in the vessel. As an extra conservatism (i.e., to show "safety margins" as specified in RG 1.174), the existing 10 CFR 50.46 acceptance criteria of 2200 °F and 17% cladding oxidation fraction were chosen as the figures of merit for demonstrating that a "coolable geometry" is maintained. In addition, the thermal-hydraulic analysis addressed localized effects by looking at a group of only four limiting fuel bundles (less than 1% of the core) representing the highest LHGR. A typical best-estimate analysis uses a coarser representation of the core (10% - 20%) as a measure for core damage. Best-estimate thermal-hydraulic models were used to demonstrate that the coolable geometry was maintained after the assumed plant changes were implemented. Best-estimate modeling is acceptable per RG 1.174, as we are dealing with an accident that is beyond the requirements of the design basis.

For identifying the most challenging set of plant changes in the implementation guide, a commonly used thermal-hydraulic model for PRAs, the MAAP4 code, was utilized in the defense-in-depth thermal-hydraulic study. Because the MAAP4 code has not been subjected to regulatory review and approval as a tool for design basis analysis, it was benchmarked against the TRACG02 code, an NRC-recognized code. The details of the benchmark process are documented in Appendix B. In the generic analysis, the MAAP4 code was used to identify the most challenging set of plant changes, and subsequently TRACG02 analyses were carried for these conditions to show that the PCT was below the defined criteria. With the benchmark complete, it is shown that the MAAP4 code is adequate for analyzing the LBLOCA/LOOP events. It is also expected that as long as the parameters used in the generic MAAP4 analysis bound the corresponding parameters for the individual licensee's plants, the results of the generic MAAP4 analyses in this LTR are applicable for those individual plants.

External Events

There are several initiating events that are not affected by the changes proposed by this report. These are internal fires, internal flood, and seismic events. This section provides a qualitative discussion of these events. ISLOCA is also discussed in this section. Other external events have been postulated for BWRs, but they do not significantly impact CDF or LERF*.

There are no credible fire events that can cause a LBLOCA, therefore the proposed changes to the operation and initiation of diesel generators will not have any detrimental effect. The improved reliability of the EDGs, however will have a beneficial effect on any fire event that results in a loss of offsite power. The changes that involve optimizing EDG loads and the configuration of RHR systems only affect a small portion of the ECCS available during LOOP events, but provide other benefits to offset the reconfiguration. A review of the importance measures for the base model and the variations confirm that these changes also have a beneficial

* Severe weather, such as hurricanes, is included in the Loss of Offsite Power initiating event.

effect on LOOP events, and by implication, fire events that result in a LOOP. It is judged that the changes proposed in this report will result in a reduction in risk for all fire initiating events.

Internal flood events are similar. There are no credible flood events that can cause a LBLOCA, therefore the proposed changes to the operation and initiation of diesel generators will not have any detrimental effect. It is also not likely that a flood will cause a loss of offsite power. If it did, the improved reliability of the EDGs will be beneficial in these particular flood sequences. It is judged that the changes proposed in this report will result in a reduction in risk for all internal flooding events.

Seismic events can cause a loss of offsite power at a BWR. For the same reasons described above, the changes proposed in this report will have a beneficial effect on these seismic events. If the magnitude of the event is large enough, it is possible that the primary system piping could be damaged*. The typical construction of BWRs is such that any earthquake that can cause a LBLOCA will also cause failure of the EDGs. Therefore, there would be no change in the CDF associated with very large seismic events. It is judged that the changes proposed in this report will result in a reduction in risk for seismic initiated events.

NUREG/CR-5750 cites the ISLOCA event frequency for BWRs as being less than 1×10^{-8} per year. This combined with the probability of failure to isolate the break (typically 0.1) and the conditional probability of LOOP (0.01) places this event frequency well beyond the realm of consideration for this report. It is judged that the changes proposed in this report will result in a negligible change in risk due to ISLOCA events.

2.3 PRA Quality

NRC has developed Regulatory Guide 1.200 (Reference 18) for trial use to address PRA technical capability. It addresses the use of the ASME PRA standard (ASME RA-S-2002, Reference 20), and the NEI peer review process, NEI 00-02 (Reference 6) for evaluating PRA technical capability.

Plants implementing any of the changes described in this report should evaluate their PRAs in accordance with this regulatory guide. RG 1.200 specifically addresses the need to evaluate important assumptions that relate to key modeling uncertainties (such as common cause failure methods, success path determinations, human reliability assumptions, etc). Further, the RG addresses the need to evaluate parameter uncertainties and demonstrate that calculated risk metrics (e.g., CDF and LERF) represent mean values. The identified "Gaps" to requirements from the endorsed PRA standards in the RG and the identified key sources of uncertainty serve as inputs to identifying appropriate sensitivity cases in Step 9 of Section 4.

* Seismic events of a magnitude great enough to damage the primary system is beyond the design basis at nuclear power plants.

2.4 Description of Potential Changes

The existing regulations requiring that all possible breaks be mitigated using onsite power sources drive many of the design and operating requirements and parameters. Some of these requirements and parameters exist for the sole purpose of mitigating the largest, least likely breaks in the absence of offsite electrical power. Implementation of these requirements and parameters can make the performance of mitigating systems less than optimal for many of the more likely events. If the performance of the mitigating systems can be optimized over the entire range of challenges, then overall plant risk can be reduced.

The following sections describe the plant changes that were analyzed in this report. Current requirements and the rationale for change are described. The risk impact of the changes is presented in Section 5.2 and Appendix C.

It is possible that other plant changes that are not explicitly described in this report can be justified using the analyses presented herein. A licensee desiring to implement another change must demonstrate that the change is equivalent to those presented in this report. If the change is not equivalent, the plant must provide a plant-specific evaluation similar to that presented in this report; and the plant must obtain approval from the NRC that the analysis method of this report is applicable to that change.

Each licensee will select the combination of changes that the licensee wishes to implement as part of the exemption request. Some combinations of the changes listed below are mutually exclusive and not possible to implement, as described in Section 4, Step 4.

2.4.1 Optimize EDG Loading

Currently, loads that are automatically sequenced on to the EDGs include a large number of high capacity pumps needed to rapidly reflood the core following the largest breaks. The EDGs are designed to carry these loads, but little more. If some of the high capacity pumps were removed from the EDG automatic loading, other more beneficial loads, for more likely LOOP scenarios than large LOCAs, could be automatically powered by the diesel generators.

Current plant procedures allow operators to secure pumps not needed for core cooling, which would allow other loads to be powered by the diesels. This, however, requires the operators to take manual actions at a time when the limited operator resources could be assigned to other tasks. Further, PRAs have generally considered such manual actions to be less reliable than automatic actions.

Some members of the BWROG have identified several types of equipment that would be valuable in LOOP scenarios in which there is not a LBLOCA. These include battery chargers, drywell coolers, and certain equipment closed cooling loops. They have indicated that automatic

initiation of LPCS pumps does not provide significant benefit in such a scenario. Others have indicated that starting only two of four LPCI pumps, instead of starting all four of the pumps, would have a negligible impact on LOOP scenarios not involving a LBLOCA.

If the requirement for automatic loading of all LPCI pumps or LPCS pumps onto the diesel generators were eliminated, licensees would perform analyses to determine which equipment would be most beneficial to have automatically loaded. They may also determine that some equipment that is currently load shed upon loss of bus voltage may not need to be shed.

The only potential detrimental effect of this change would be that some LBLOCA events with a concurrent loss-of-offsite power and an additional single failure may lead to core damage. The beneficial effect of this change depends on the plant's use of the additional load margin on the EDGs. In Appendix C, this report performs a generic risk evaluation of the effect of automatically powering the battery chargers from emergency onsite power and eliminating automatic load of LPCS pumps or some LPCI pumps onto the EDGs. (In this analysis, all low-pressure ECCS pumps are assumed to automatically start on a LOCA signal as long as offsite power remains available.) This has the benefit of reducing operator burden during loss-of-offsite power sequences, e.g., by eliminating the need to reduce DC loads, monitor battery consumption, and manually re-start the chargers. There are also fewer pumps that need to be secured by the operators that are not needed for extended core cooling. This benefit has been evaluated using the generic PRA model discussed in Appendix C. Other benefits that are more difficult to quantify include additional voltage margin afforded DC powered equipment if the chargers can be credited in the plant safety analysis.

2.4.2 One RHR Loop in Suppression Pool Cooling Mode

Currently, instrumentation logic is such that both RHR divisions start in LPCI mode on a LOCA signal. The logic signal is locked in until the core reflood is complete. Later in the postulated accident sequence, at least one division of RHR is required to be manually re-aligned to one of the containment cooling modes. While this strategy works well for LBLOCA scenarios, it is not as effective for smaller breaks and transient scenarios.

If LBLOCA scenarios did not require consideration of concurrent loss-of-offsite power, many BWRs would be able to modify their RHR logic such that at least one RHR loop would be started automatically in suppression pool cooling mode. This eliminates the need for a manual mitigation action that is important in all LOCAs and transients. To make this change, a licensee would need to deterministically demonstrate that it could still mitigate the LBLOCA with offsite power available and a single active failure. (See Appendix B for such an analysis for a generic BWR plant).

Making this change would reduce CDF associated with sequences involving loss of containment heat removal because the main system for performing this function would be initiated automatically rather than manually. However, the change would increase the CDF for sequences involving loss of coolant injection, because only one division of RHR would be started automatically in LPCI mode. Further, LPCI could not be used to automatically reflood the core in those LBLOCA scenarios in which the break is in the recirculation loop that receives the LPCI flow. Because loss-of-containment heat removal sequences make up a larger fraction of the BWR risk profile than loss of injection sequences, this change would result in a net reduction in CDF.

2.4.3 Eliminate LPCI Loop Select

Some BWRs have a logic system called LPCI Loop-Select Logic. In the event of a Recirculation line break, this system monitors both Recirculation loops and repositions valves to isolate the broken Recirculation loop and directs all LPCI flow to the Recirculation loop that is intact, i.e., does not have the LOCA. To assure that the required valves will have power under all assumed single failures, they are powered from a "swing bus" that is power-seeking from either division of on-site or off-site AC power. This logic is very complicated, and therefore it is difficult to maintain and test. A typical test of this system includes multiple jumpers, lifted leads, and blocked relays to simulate the accident condition while protecting other equipment from damage. Elimination of this testing greatly reduces the potential for restoration errors or equipment damage during the testing.

In the current deterministic LOCA analyses for Loop-Select plants, the logic is assumed to fail (i.e. select the broken loop for LPCI injection) for all breaks less than or equal to 0.5 ft². This is well into the large break range, so elimination of this function will not affect the deterministic analysis of other postulated accidents. When offsite power is available, there are no single failures that would prevent reflood following a LBLOCA if Loop-Select were eliminated.

2.4.4 Allow EDG Warm Up Prior to Loading

Current EDG start and load times are set to a time short enough that the core can be re-flooded prior to core damage for all break sizes. The start time is typically on the order of 10 seconds and such a start is referred to as a "fast start". It is generally accepted that fast starts and loading take a toll on the components in the engine. Historically, this rationale has been accepted by the NRC as a basis for reducing the number of fast start tests that are required. Fast start tests, however, have not been eliminated. In addition, inadvertent and anticipatory logic starts of the EDGs are fast starts.

Even though current maintenance practices sufficiently counter EDG wear during performance of current design basis tasks, including fast starting, fast starts in general are not good for the engines, and any decrease in their number would be expected to incrementally improve EDG

performance. Quantification of this improvement is difficult, but the overall effect will be neutral or slightly positive.

If the requirement for fast start were eliminated, the EDG starting circuits could be modified to allow an interval of warm up at idle speed before accelerating the engine to full speed and loading the bus. Diesel engineers at BWROG member plants have indicated that any warm up time would be beneficial, but 30 seconds to a minute warm up duration is expected to yield noticeable benefits. GE analysis of industry data indicates that diesel start and load times of less than 100 seconds would satisfy current 10 CFR 50.46 requirements for all but the large recirculation loop pipe breaks. (For these smaller breaks, the controlling factor is the time to depressurize to the pressure permissive; this is greater than 100 seconds). Analyses using realistic assumptions, documented in Appendix B, have shown that acceptable PCT values would be maintained for the largest LBLOCA break sizes.* Therefore, the effect of fast start elimination would be an incremental increase in the reliability and availability of the diesel generators.

2.4.5 Start EDGs Only When Needed

The EDGs are currently started on any single indication of a LOCA (i.e. high drywell pressure or low reactor water level), regardless of the state of the offsite power sources. This has caused actuation of the diesels when they were not needed, resulting in unnecessary demand on the equipment. Additionally, personnel are required to secure the unneeded diesel, diverting resources that could have been used to directly address the transient.

If the requirement for this anticipatory start were eliminated, licensees could change the EDG start logic so that the engine would start only on bus under-voltage or degraded voltage conditions, i.e., anticipatory starts on ECCS logic accident signals would no longer occur. The only scenarios whose response would be adversely affected by this change would be a subset of very large recirculation line breaks in which offsite power was lost as a consequence of starting the ECCS system. If the power loss occurred concurrent with or a few seconds following the LOCA, the current accident analysis would be virtually unchanged. If the power loss occurred more than a few minutes after the LOCA, reflood would have been substantially complete, peak clad temperature would have already been reduced, and the additional time to start the EDGs would not affect long-term cooling.

One of the safety benefits of eliminating the anticipatory EDG starts comes from the reduction of operator burden following accidents and transients. When a diesel generator is started, but not needed to power plant loads, it runs unloaded. The BWROG diesel generator engineers have indicated that running unloaded for an extended period of time is detrimental to the machine.

* Plants must still demonstrate that the remaining break sizes are acceptable using current 10 CFR 50.46 criteria. See Section 4, Step 24 for a more complete description of this requirement.

Currently licensees secure unneeded diesels to prevent damage to the machine. This can take the attention of several operators. When multiple diesels start, as is the case for the anticipatory logic, the situation is exacerbated. Therefore, if the operators do not have to divert resources to tending diesel generators, one can assume that other post initiator operator actions assessed in the PRA would be somewhat more reliable. This effect was analyzed using the generic PRA model described in Appendix C.

Another safety benefit of eliminating the anticipatory EDG starts comes from an increase in diesel availability and reliability. When spurious EDG starts occur, remedial actions, such as running the EDG under load for a period of time to clear cylinder soot buildup, are typically necessary to restore the equipment to full integrity. This effect has been analyzed using the generic PRA model discussed in Appendix C. Additionally, a diesel generator that has been unnecessarily started during an accident or transient and has been successfully secured may incur damage if offsite power is subsequently lost and an actual start demand occurs soon after the EDG shutdown. One mechanism for this damage is that the hotter oil in a recently shutdown EDG does not lubricate all portions of the EDG, such as turbochargers, as well as if the oil was at normal, standby temperature.

A third safety benefit of eliminating the anticipatory EDG starts is that there should be fewer spurious EDG actuations. A reduction of the number of signals that will cause a start will result in a reduction of the number of spurious starts. Since any reduction in demands reduces wear on the equipment, unavailability should decrease and reliability should increase as a direct consequence of this change.

2.4.6 Simplified EDG Testing

Testing is required on the current functions of starting and loading EDGs. Changes under this option would not alleviate the need for such testing, but the acceptance criteria for such testing would be relaxed and the overall testing scope would be significantly reduced. Significant maintenance time associated with diesel generators is spent meeting these acceptance criteria. This affects both the generator and the logic associated with shedding equipment and the subsequent reload of required equipment. Redefining these acceptance criteria would not significantly affect any but the most limiting LOCA scenarios. However, relaxing these acceptance criteria has the potential to reduce unavailability of the EDG function. There is an additional benefit that some of the tests could be simplified, which in turn could result in fewer operator distractions during plant operation.

For example, to satisfy the accident response assumptions associated with a LBLOCA concurrent with LOOP, RHR pumps must load onto the EDG-powered board immediately (typically less than 1 second) after the EDG ties to the board. The EDG is therefore subjected to the application of a very large load just a few seconds after its cold, fast start. Additional loads

are sequenced onto the EDG in fairly quick succession. The timing relays which accomplish this loading have tight tolerances, both to assure reflood times are within those assumed in the accident analyses, and also to ensure that the EDG can recover adequately before the next load is applied.

Upon separation of the LOOP and LOCA events as requested by this LTR, the EDG is allowed a warm-up period prior to connecting to the associated electrical board. The start times of the RHR pump and other loads are not as critical in a smaller break scenario, so the timing relays' tolerance need not be so tight, and the EDG can be allowed a greater recovery time between load applications. The longer start times impose less stress upon the EDG and require less timing precision in the loading sequences, while maintaining adequate margins to accident analyses assumptions.

Additionally, since EDG's will no longer have to carry all of the large pump motor loads associated with LBLOCA mitigation, the EDG's will have additional capacity to supply other loads that often have to be shed under the current regulatory requirements. Testing, maintenance, and plant perturbations associated with this load shedding could be greatly reduced and in some cases would no longer be necessary at all. The reduction or elimination of the complex plant equipment manipulations generally necessary for such load shed logic testing and maintenance would allow the plant staff to focus its attention on more risk-significant activities.

~~2.4.7~~ *Increased MOV Stroke Times*

Current MOV stroke times are set short enough so that the core can be re-flooded prior to core damage for all break sizes following a loss-of-offsite power and subsequent EDG start and load. This has caused plant designs to require fairly large valve operators to meet the open or close times. The combination of oversized operators and severe test conditions causes significant wear on the valves. In addition, the electric power requirements for the larger operators, while much less than those for the pumps, can add to EDG loading constraints.

Separating LBLOCA from LOOP will not alter test conditions, but will allow slower valve stroke times. If the stroke time were slower, lower torques would be required to change the state of the valve. This would allow slower operating speeds for the motors and gears, thus allowing smaller operators, or more margin for the current operators (Reference 9).

As with the EDGs, valves that are made more reliable through a reduction of wear also have better availability. The potential detriment would be that a subset of LBLOCA with LOOP scenarios might lead to core damage. However, as discussed in Section 2.5, generic thermal-hydraulic analyses using realistic analyses have shown that adequate PCT would be maintained for a wide range of stroke time relaxations. The maximum time increase would be limited by the acceptance criteria for the LBLOCA.

If a licensee chooses to make this change, licensees would review their maintenance data and determine which MOVs have disproportionate preventive or corrective maintenance associated with preserving a stroke time that is artificially short due to the current LBLOCA-LOOP requirement. The impact of this effect is not quantified in the generic example of Appendix C. This impact is difficult to quantify and it is not recommended that licensees attempt to quantify this effect. In any event, it is expected that this change will result in a small, but positive impact on risk, due to reduced MOV maintenance unavailability.

An additional benefit from this change would be that smaller operators would reduce seismic loading on some plant pipes. This report does not attempt to quantify the magnitude of the seismic benefit of this change.

2.5 Thermal-hydraulic Analysis

As outlined in Section 2.2 of this report, the defense-in-depth philosophy has traditionally been applied in reactor design and operation to provide multiple means to accomplish safety functions and prevent the release of radioactive material. In order to demonstrate defense-in-depth for the LBLOCA-LOOP separation exemption, per RG 1.174, the BWROG will demonstrate that the LBLOCA/LOOP event can continue to be mitigated, even after the implementation of the plant modifications discussed in Section 2.4 (LBLOCA/LOOP changes). However, as discussed in Section 4.0, individual licensees requesting exemptions will have to either verify that these analyses are applicable for their plants or perform the needed plant-specific analyses. The thermal-hydraulic analyses summarized here and detailed in Appendix B are not applicable to BWR2 plants. BWR2 plants will need to perform a plant-specific thermal-hydraulic analysis as part of their exemption request.

Plant changes associated with implementation of LBLOCA/LOOP changes will result in a delay in the start of ECCS injection. They will also result in converting some equipment from automatic to manual operation and vice versa. Therefore, the impact of these changes was evaluated to determine the viability of implementing them. Given the low probability of a LBLOCA occurring concurrent with a LOOP, this event will now be considered a "mitigated beyond design basis accident." Consistent with this re-categorization, this evaluation was performed using realistic assumptions and methods. Consistent with the use of best-estimate methods and assumptions, the acceptance criterion for the analyses was established to be maintaining the core in the reactor vessel in a coolable geometry.

As discussed earlier, some measure of mitigation capability should be retained for the new beyond design basis event of the LBLOCA/LOOP, assuming the other plant changes were implemented. For the "mitigated beyond design basis accident", some level of core damage can be tolerated. In addition, by definition, a LOCA is a breach of the fission product barrier of the reactor coolant pressure boundary. Thus, to ensure that the next fission product barrier of the

containment was not challenged by this new event, it was decided that retaining the core material inside the reactor vessel would be used as the acceptance criterion for mitigation. Maintaining the fuel in a "coolable geometry" was chosen to ensure that the core material was retained in the vessel. As an extra conservatism (i.e., to show "safety margins" as specified in RG 1.174), the existing 10 CFR 50.46 acceptance criteria of 2200 °F peak cladding temperature (PCT) and 17% local cladding oxidation fraction were chosen as the figures of merit for demonstrating that a "coolable geometry" is maintained. In addition, the thermal-hydraulic analysis addressed localized effects by looking at a group of 4 limiting fuel bundles (less than 1% of the core) representing the highest LHGR. A typical best-estimate analysis uses a coarser representation of the core (10% - 20%) as a measure for core damage.

The MAAP4 code is capable of performing the required thermal-hydraulic analysis. However, because the MAAP4 code has not been subjected to regulatory review and approval as a tool for design basis analysis, it was benchmarked against the TRACG02 code, an NRC-recognized code. The benchmark analyses documented in Section B.4 showed that the TRACG02 and MAAP4 PCT values compared reasonably well. Then a series of analyses were performed with MAAP4 with the proposed plant modifications implemented in the plant. The results, which are documented in Section B.5, showed that all acceptance criteria are met. For added measure of confidence, the two most limiting MAAP4 cases were reanalyzed using the TRACG02 computer code. The results of that analysis are documented in Section B.4. The TRACG02 results showed that MAAP4 results are relatively conservative, i.e., they over predict the PCT values.

Additional MAAP4 cases were analyzed to assess the impact of plant-to-plant variability on the results of the analysis. These sensitivity analyses are documented in Section B.6. It was demonstrated that changes in RPV liquid volume of +20% and a variation in ECCS injection flow of 10% did not generate significant changes in PCT that would alter the conclusions of this evaluation.

The results of Appendix B are applicable to all BWR 3,4,5 and 6 product lines, as discussed further in the appendix. BWR2 plants were not specifically analyzed, and plant-specific thermal-hydraulic analysis would be required as part of their exemption request submittals.

The details of the thermal-hydraulic assessment described above are provided as Appendix B to this report.

2.5.1 Methodology

The specific approach used to evaluate the impact of the proposed LBLOCA/LOOP changes was as follows:

- Preliminary analyses using MAAP4 and TRACG02 identified certain changes to be made to the MAAP4 model after which the MAAP4 analyses provide results

similar to TRACG02 results. The preliminary analyses were also used to identify the limiting cases for use in a benchmark analysis of MAAP4 and TRACG02.

- Benchmark LBLOCA cases were performed with both the MAAP4 and TRACG02. The benchmark analyses are discussed in Appendix B, Section B.4. The benchmark analyses were performed to demonstrate that MAAP4 can be used for any plant-specific thermal-hydraulic analyses that may be necessary.
- A series of MAAP4 cases was analyzed using the various equipment combinations resulting from implementing all of the LBLOCA/LOOP changes. These cases are discussed in Appendix B, Section B.5.
- A series of MAAP4 sensitivity cases to evaluate the effect of plant-to-plant variability were performed. The sensitivity analysis is discussed in Appendix B, Section B.6.
- As a measure of additional conservatism, the MAAP4 case with the highest PCT for the BWR4 and one for the BWR6 are run using TRACG02 as part of the benchmark analysis described in Section B.4 to provide a separate demonstration of defense-in-depth after implementation of LBLOCA/LOOP. It should be noted that the BWR6 case, although not the highest PCT, was chosen because it offered the opportunity to evaluate the impact of the LBLOCA/LOOP changes in scenarios requiring both high pressure and low-pressure injection sources. The difference in peak PCT between the BWR6 case selected and the BWR6 case with the highest PCT is less than 100 °F and there is significant margin to the 2200 °F acceptance criteria. The MAAP4 and TRACG02 analyses are provided in Appendix B, Section B.4.

The thermal-hydraulic analyses performed in the benchmark and sensitivity analyses in Appendix B evaluated the impact of plant variability with respect to RCS volume, available ECCS injection systems, ECCS injection flow rate and the timing of ECCS injection.

The assumptions in Table 2-3 below need to be validated by each applicant to ensure that the analyses in this report are applicable. The RPV volume variability sensitivity analyses encompassed a wide-enough range to preclude the need for further validation.

The minimum system availability requirements are needed to preserve the defense-in-depth. In this way, a LBLOCA with an assumed LOOP must have at least this minimum set of ECCS available for injection within the assumed time delay interval, in order to conform to the assumptions of the analyses performed in Appendix B.

The ECCS injection flows shown reflect the lower end of the variability analysis range. The break size used in the analysis is provided in Table 2-3 below. Plants with smaller recirculation lines can accommodate a lower ECCS injection flow rate.

2.5.2 Summary of Results and Conclusions

The representations of LBLOCA/LOOP plant changes are provided in Table 2-1 below. Table 2-2 provides the limiting combinations of ECCS delay and available ECCS systems derived from Table 2-1.

The MAAP4 sensitivity analyses demonstrated that the plant-to-plant variation in RPV liquid volume and ECCS injection flow did not generate changes in PCT that would alter the conclusions of the evaluation. This range of RPV liquid volume and ECCS injection flow encompasses the expected plant type variability.

The objective of maintaining the core in the reactor vessel in a coolable geometry was met with significant margin. The MAAP4 cases for the limiting scenarios predict a peak clad temperature that is less than 2200 °F and no significant clad oxidation (much less than 1% global and less than 5% local clad reacted). The TRACG02 cases also predict PCT values less than 2200 °F. Therefore, the BWROG has demonstrated that defense-in-depth, as specified in RG 1.174, has been achieved, with the adoption of the LBLOCA/LOOP changes.

It is concluded that MAAP4 is an acceptable tool for performing the thermal-hydraulic analyses required for the LBLOCA/LOOP exemption for the specific cases analyzed here. As discussed in Section B.4.4, the results compare favorably between the MAAP4 and TRACG02.

It is also concluded that the MAAP4 results, provided in this appendix, are applicable to BWR 3/4/5/6 plants, as long as the plant parameters fall within the bounds of the input parameters used in the generic analyses of this appendix. If the licensee's plant meets these criteria, there is no need for additional, plant-specific thermal-hydraulic analysis to support licensee's exemption request

Table 2-1 Bounding Representation of LBLOCA/LOOP Plant Changes

Category		Change	Effect	Bounding Effect on ECCS		
				BWR 3/4		BWR 3/4 w/ Loop-Select
1		Allow EDG Warm up Prior to Loading	Delayed Injection	90 Second EDG Delay*		120 Second EDG Delay*
		Start EDGs Only When Needed				
		Increased MOV stroke times				
2a		Optimize EDG loading	Reduced Injection	No LPCS		Loss of 1 LPCI pump and 1 LPCS Pump
2b				Loss of 2 LPCI Pumps		
3		One loop of RHR in SPC mode	Reduced Injection	No LPCI		Loss of 1 LPCI Loop
4		Eliminate LPCI LOOP Select	Reduced Injection	N/A	Loss of 1 LPCI Loop	N/A
N/A		Simplified EDG testing	N/A	N/A		

* Nominal valve stroke and pump coast-up time assumed for ECCS equipment operation is included in addition to the EDG delay.

Table 2-2 Limiting Combination of ECCS Delay and Reduced Injection

Case	Plant Type	Category Combination**	EDG Delay Time (sec)	Number of Injection Pumps		
				LPCI	LPCS	HPCS
A	BWR 3/4	1 & 2 & 4***	90	2	0	N/A
B		1 & 3		0	2	N/A
C	BWR 5/6	1 & 2 & 3	120	1	0	1
D				2	0	0
E				0*	1	1

* Includes an additional LPCI failure to make it a unique case.

** Category corresponds to Table B.5-1.

*** Elimination of LPCI LOOP select logic is accounted for by crediting only 1 loop of LPCI (2 pumps)

Table 2-3 Thermal-Hydraulic Parameters Used in Analyses

Item #	Item	Assumption	
1	BWR 3/4 ECC System Availability Requirements (Minimum system combinations available after time delay for a LBLOCA with a LOOP)	2 LPCI or 2 LPCS or 1 LPCI + 1 LPCS	
2	BWR 5/6 ECC System Availability Requirements (Minimum system combinations available after time delay for a LBLOCA with a LOOP)	2 LPCI or 1 LPCI + 1 HPCS or 1 LPCS + 1 HPCS	
3	BWR 3/4 EDG Time Delay	≤ 90 seconds	
4	BWR 5/6 EDG Time Delay	≤ 120 seconds	
5	BWR 3/4 ECCS Injection (Minimum LPCI Flow Requirements)	RCS Pressure (psia)	LPCI Flow (ft ³ /hr)
		210.7	0.0
		191.1	34184.7
		171.5	48347.1
		132.3	68370.3
		93.1	83730.6
		53.9	96678.0
		34.3	102555.0
		0.0	108108.0
6	BWR 3/4 ECCS Injection (Minimum LPCS Flow Requirements)	RCS Pressure (psia)	LPCS Flow (ft ³ /hr)
		279.7	0.0
		253.7	12350.7
		226.7	17468.1
		200.7	21394.8
		173.7	24707.7
		147.7	27623.7
		127.7	29594.7
		14.7	39065.4

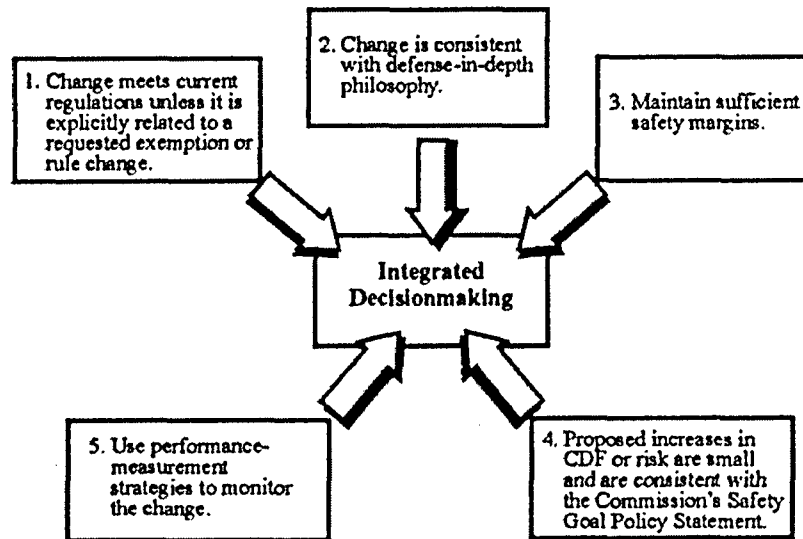
Table 2-3
Thermal-Hydraulic Parameters Used in Analyses (continued)

Item #	Item	Assumption	Item #
7	BWR 5/6 ECCS Injection (Minimum LPCI Flow Requirements)	RCS Pressure (psia)	LPCI Flow (ft ³ /hr)
		323.7	0.0
		313.7	8698.6
		275.5	21764.4
		246.2	32700.8
		194.7	45261.4
		156.6	52516.2
		131.6	56414.3
		113.6	59265.7
8	BWR 5/6 ECCS Injection (Minimum HPCS Flow Requirements)	RCS Pressure (psia)	HPCS Flow (ft ³ /hr)
		1387.0	0.0
		1386.0	4330.8
		1212.0	14436.0
		1104.0	21654.0
		996.0	28872.0
		779.0	36090.0
		541.0	43308.0
		271.0	50526.0
9	BWR Vessel Diameter	218 to 251 inches	
10	Peak Linear Heat Generation Rate Basis	13.4 kw/ft	
11	Initial Critical Power Ratio Basis	1.21	
12	Analyzed Break Area	4.5 ft ²	

3.0 KEY SAFETY PRINCIPLES

RG 1.174 identifies five key safety principles to be met for all risk-informed applications and to be explicitly addressed in risk-informed plant program change applications.

Figure 1 of RG 1.174 illustrates the consideration of each of these principles in risk-informed decision-making.



The discussions related to meeting each of the five key safety principles, provided in the following sections, were developed during the performance of the generic example analyses described in Appendix B and Appendix C. These discussions are generally applicable to all BWR plants, but should be reviewed by each licensee and revised to make the discussions plant-specific for inclusion in the exemption request, as described in Section 4, Steps 19 through 23.

3.1 Compliance with Current Regulations

3.1.1 *The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.*

The changes proposed in Section 2.4 require a specific exemption, pursuant to 10 CFR 50.12, to key provisions of 10 CFR 50.46, namely §50.46(c)(1) and (d). §50.46(c)(1) defines the spectrum of break sizes that must be postulated within the design basis, which includes the classic LBLOCA resulting from the double-ended guillotine break of the largest pipe in the reactor coolant system. §50.46(d) specifically invokes the ECCS design requirements as currently set forth in General Design Criterion (GDC) 35 (Appendix A to 10 CFR 50), which contains the assumption of the simultaneous LOOP with the LOCA.

The proposed changes in this LTR require a limited exemption to the above requirements. Under the proposed exemption, the ECCS design basis under §50.46(c)(1) and (d) for BWRs would no longer include an assumed LOOP coincident with breaks in “large” pipes (nominally pipe diameters greater than or equal to 10 inches) in the reactor coolant pressure boundary. The coincident LOOP and LOCA assumption would, however, continue to apply for breaks smaller than this “large” break size. In addition, per GDC 35, the LBLOCA would still be postulated to occur with off-site power available.

3.1.2 Justification for the Exemption

10 CFR 50.12(a)(1) allows exemptions that are “Authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security.”

As discussed below, the requested exemption satisfies the requirements in 10 CFR 50.12:

The requested exemption is not inconsistent with any law

There is nothing specific in the Atomic Energy Act or other statute applicable to the NRC that requires that the LOOP assumption be applied to the design or analysis of ECCS for nuclear power plants, or that the NRC establish or implement the design criterion in question.

The requested exemption would not present an undue risk to the public health and safety

As described in this LTR, the overall risk to the public health and safety is smaller than the threshold values specified in RG 1.174, and this small risk increase can be at least partially offset by the implementation of plant modifications that require issuance of the requested exemption. Approval of this exemption would make it possible for individual plants to implement the changes described in Section 2.4 of this LTR and thereby achieve a better balance in overall plant risk by optimizing the performance of the mitigating systems for other events that are more likely to occur than the LBLOCA/LOOP. Further, as discussed in Sections 3.2 and 3.3 of this LTR, implementation of the requested exemption will not adversely affect defense-in-depth or safety margins. Therefore, the exemption will not adversely affect the public health and safety.

The requested exemption is consistent with the common defense and security

The requested exemption does not pertain to safeguarding of Special Nuclear Material, the protection of Restricted Data, the availability of Special Nuclear Material for defense needs, or foreign control over power plant operation. Therefore, it does not have any effect on the common defense and security.

In addition, 10 CFR 50.12(a)(2) stipulates that “special circumstances” must be present before the Commission will consider granting an exemption. Special circumstances are present whenever:

1. Application of the regulation in the particular circumstances conflicts with other rules or requirements of the Commission; or
2. Application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule; or
3. Compliance would result in undue hardship or other costs that are significantly in excess of those contemplated when the regulation was adopted, or that are significantly in excess of those incurred by others similarly situated; or
4. The exemption would result in benefit to the public health and safety that compensates for any decrease in safety that may result from the grant of the exemption; or
5. The exemption would provide only temporary relief from the applicable regulation and the licensee or applicant has made good faith efforts to comply with the regulation; or
6. There is present any other material circumstance not considered when the regulation was adopted for which it would be in the public interest to grant an exemption.

The BWROG believes that special circumstances, as defined above, exist, as follows:

Satisfaction of the Second Criterion for Special Circumstances

The purpose of §50.46 is to ensure a highly reliable ECCS that is capable of removing sufficient heat to assure that the fuel remains in a coolable geometry and negligible metal-water reactions take place for the postulated accident scenarios. As demonstrated herein, the underlying purpose of this regulation can still be achieved with the proposed changes.

The goal of this exemption is to improve the overall reliability of the ECCS and the supporting on-site power supply, i.e., the EDGs, by removing the existing design and testing constraints that are in place solely to mitigate the most-unlikely subset of postulated LOCA events. The evaluations in Section 5 of this LTR demonstrate that such improvements in reliability are achievable and tend to offset the small assumed increase in risk due to removing the LBLOCA/LOOP event from the design and licensing basis.

As shown in Section 2.5 of this LTR, the ability to achieve the underlying objective of a coolable geometry and negligible metal-water reaction remains satisfied, even with the removal of this subset of LOCA events from the design basis. Thus, the underlying objectives of §50.46 remain satisfied with the proposed exemption.

Satisfaction of the Fourth Criterion for Special Circumstances

As stated in Section 2 of this LTR, the purpose of this exemption request is to improve overall plant risk by optimizing the performance of key safety system equipment to respond to the most likely set of events, by eliminating the performance requirements on that equipment that exist solely to respond to a small subset of events that are known to be highly improbable. The evaluations in Section 5 of this LTR demonstrate that such improvements are achievable and tend to offset the assumed increase in risk due to removing the LBLOCA/LOOP event from the design and licensing basis.

Satisfaction of the Sixth Criterion for Special Circumstances

Since the subject regulations were promulgated in the early 1970's, a substantial amount of research and development devoted to piping failure mechanisms, accident thermal-hydraulic phenomena, and quantitative plant risk assessments has taken place. Application of these technologies demonstrates the excessive conservatism in the original regulations. As noted in Section 1 of this report, so much conservatism exists that it constitutes an unnecessary burden on the licensees that warrants relief through both permanent rulemaking and, in the interim, exemption to these requirements. And, as demonstrated in Section 2.5 of this report, such relief could be used to make improvements in overall plant safety that would otherwise not be possible. Thus, it would be in the public interest to consider this new material information that was not present when the regulations were originally promulgated.

3.1.3 Compliance With Related Regulations

There are a number of additional regulations and GDCs that require the assumption of a LOOP, some in combination with LOCA. Because they are not the subjects of this exemption request, continued compliance with these regulations, considering the proposed changes described in Section 2.4 of this LTR, is demonstrated in the following subsections.

3.1.3.1 10 CFR 50.34(f) – Additional TMI Requirements

10 CFR 50.34(f)(1) has two requirements related to a LOOP. These are:

- (iii) Perform an evaluation of the potential for and impact of reactor coolant pump seal damage following small-break LOCA with loss-of-offsite power. If damage cannot be precluded, provide an analysis of the limiting small-break loss-of-coolant accident with subsequent reactor coolant pump seal damage, and
- (ix) Perform a study to determine the need for additional space cooling to ensure reliable long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems, following a complete loss-of-offsite power to the plant for at least two (2) hours. (For plants with high pressure

core spray systems in lieu of high pressure coolant injection systems, substitute the words, "high pressure core spray" for "high pressure coolant injection" and "HPCS" for "HPCI") (applicable to BWR's only).

BWROG Compliance

With respect to (iii) above, this issue is applicable only to B&W plants, see NUREG-0737, Item II.K.2.16.

With respect to (ix) above, as noted in Section 2.4 of this LTR, these plant loads are not targeted for removal from the on-site power supplies (EDGs). In addition, per Section 5 (and Attachment C) of this LTR, the space cooling capability to ensure reliable long-term cooling operation of the RCIC and HPCI following a LOOP is not being reduced.

3.1.3.2 10 CFR 50.63 Loss of All Alternating Current Power

10 CFR 50.63(a)(1) requires, in part, "Each light-water-cooled nuclear power plant licensed to operate must be able to withstand for a specified duration and recover from a station blackout."

BWROG Compliance

The plant capability for coping with a SBO is not reduced by the requested exemption. Because the coping capability generally requires the assumption of the unavailability of both offsite and onsite AC power for the coping period duration, there is no change to analyzed capability, as the changes outlined in Section 2.4 of this LTR involve equipment that is not relied upon during this coping period (e.g., LPCS and RHR are AC-powered). Once onsite AC power is restored, plant modifications to the EDG loading may provide some additional capability during the recovery period.

3.1.3.3 10 CFR 50 Appendix A – General Design Criteria (GDC)

For certain BWRs, compliance with the GDC is not part of their licensing and design basis. The following discussion of conformance is not intended to mandate a change to any plant's licensing basis, but to illustrate that the LBLOCA/LOOP changes have no impact on the continued provision of the capabilities specified in the GDCs.

Criterion 17—Electric Power Systems

GDC 17 specifies, in part: "An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result

of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.”

BWROG Conformance

The proposed exemption is for the elimination of the assumption of a concurrent LBLOCA/LOOP. There is no change to the offsite power supplies being proposed by this LTR, and they remain capable of providing sufficient power to permit functioning of structures, systems, and components (SSCs) important to safety to meet the stated objectives of GDC 17. The restructuring and timing of large electrical loads onto the essential busses outlined in Section 2.4 of this LTR, when powered from onsite power, does not adversely impact the reliability of offsite power.

The onsite power supplies remain capable of automatically providing the required safety functions for a concurrent Small Break LOCA and LOOP. Even though the concurrent LBLOCA/LOOP would be considered beyond the plant’s design basis, the realistic ECCS performance analyses in Section 2.5 of this LTR demonstrate that a coolable geometry for the core is maintained for the identified changes to the EDG loading and other potential plant modifications. As demonstrated in Section 5, enhancements in the reliability of onsite power are possible with the changes proposed in Section 2.4. As discussed in Section 3.2 of this LTR, containment integrity and other fission product barriers remain intact as a result of the proposed changes.

Therefore, the specified capabilities identified by GDC 17 continue to be provided.

Criterion 33—Reactor Coolant Makeup.

GDC 33 specifies: “A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.”

BWROG Conformance

The proposed exemption does not seek relief from the §50.46 requirement for an assumed concurrent Small Break LOCA and LOOP. In a BWR, GDC 33 conformance is met by any of several high-pressure makeup systems, depending upon break size. Some of these makeup

systems are independent of offsite or onsite AC power. As outlined in Section 2.4 of this LTR, no high-pressure makeup systems are being revised.

Therefore, the specified capabilities identified by GDC 33 continue to be provided.

Criterion 34—Residual Heat Removal

GDC 34 specifies: “A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.”

“Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.”

BWROG Conformance

In a BWR, decay and residual heat are removed from the reactor during abnormal operating events by the RHR system, in conjunction with the RHR Service Water system, either directly, via the RHR-SDC or RHR-LPCI modes; or indirectly, via the RHR-SPC or RHR-Containment Spray modes.

The residual heat removal capability is not reduced by the proposed exemption. There are no changes to the offsite power supply system. The capability of the onsite power supply system to support the residual heat removal function remains unchanged. The EDG loading sequencing may change due to the elimination of the design requirement for the assumption of a concurrent LBLOCA/LOOP. Depending on the specific plant modifications implemented, it may be possible to automatically load a suppression pool cooling system, which would provide a reduced risk for event sequences requiring suppression pool cooling.

Therefore, the specified capabilities identified by GDC 34 continue to be provided.

Criterion 38—Containment Heat Removal

GDC 38 specifies: “A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss-of-coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power

system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.”

BWROG Conformance

The containment heat removal capability is not reduced by the proposed exemption. There are no changes to the offsite power supply system. The capability of the onsite power supply system to support the containment heat removal function remains unchanged. The EDG loading sequencing may change due to the elimination of the design requirement for the assumption of a concurrent LBLOCA/LOOP. Depending on the specific plant modifications implemented, it may be possible to automatically load a suppression pool cooling system, which would provide a reduced risk for small break LOCA sequences requiring suppression pool cooling.

Therefore, the specified capabilities identified by GDC 38 continue to be provided.

Criterion 41—Containment Atmosphere Cleanup

GDC 41 specifies: “Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quality of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.”

BWROG Conformance

The containment atmosphere cleanup capability is not changed by the proposed exemption. There are no changes to the offsite power supply system. The capability of the onsite power supply system with respect to the containment atmosphere cleanup function remains unchanged. No changes are proposed for the required systems.

Therefore, the specified capabilities identified by GDC 41 continue to be provided.

Criterion 44—Cooling Water

Criterion 44 specifies: “A system to transfer heat from structures, systems, and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall

be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.”

BWROG Conformance

The cooling water capability is not reduced by the proposed exemption. There are no changes to the offsite power supply system. The capability of the onsite power supply system to provide cooling water remains unchanged. The EDG loading sequencing may change due to the elimination of the design requirement for the assumption of a concurrent LBLOCA/LOOP. Depending on the specific plant modifications implemented, it may be possible to automatically load additional cooling water systems on the EDGs, which would provide an overall reduced risk for events sequences requiring cooling water.

Therefore, the specified capabilities identified by GDC 44 continue to be provided.

3.1.3.4 10 CFR 50 Appendix R—Fire Protection Program For Nuclear Power Facilities Operating Prior To January 1, 1979

10 CFR 50, Appendix R, Section III, has four requirements related to a LOOP. These are:

F. *Automatic fire detection.* Automatic fire detection systems shall be installed in all areas of the plant that contain or present an exposure fire hazard to safe shutdown or safety-related systems or components. These fire detection systems shall be capable of operating with or without offsite power.

H. *Fire brigade ...* At least a 1-hour supply of breathing air in extra bottles shall be located on the plant site for each unit of self-contained breathing apparatus. In addition, an onsite 6-hour supply of reserve air shall be provided and arranged to permit quick and complete replenishment of exhausted air supply bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air shall be used and the compressors shall be operable assuming a loss-of-offsite power. Special care must be taken to locate the compressor in areas free of dust and contaminants.

L. *Alternative and dedicated shutdown capability.*

1. Alternative or dedicated shutdown capability provided for a specific fire area shall be able to (a) achieve and maintain sub critical reactivity conditions in the reactor;

(b) maintain reactor coolant inventory; (c) achieve and maintain hot standby conditions for a PWR (hot shutdown for a BWR); (d) achieve cold shutdown conditions within 72 hours; and (e) maintain cold shutdown conditions thereafter. During the post-fire shutdown, the reactor coolant system process variables shall be maintained within those predicted for a loss of normal AC. Power, and the fission product boundary integrity shall not be affected; i.e., there shall be no fuel clad damage, rupture of any primary coolant boundary, or rupture of the containment boundary. And,

2. The shutdown capability for specific fire areas may be unique for each such area, or it may be one unique combination of systems for all such areas. In either case, the alternative shutdown capability shall be independent of the specific fire area(s) and shall accommodate post-fire conditions where offsite power is available and where offsite power is not available for 72 hours. Procedures shall be in effect to implement this capability.

BWROG Conformance

With respect to Item F above, there are no identified changes to the fire detection system.

Therefore, the current capability remains unchanged.

With respect to Item H above, there are no identified changes to the fire brigade capability.

Therefore, the breathing air capability is not changed.

With respect to Item L.1 above, plant capability with respect to fire protection is not reduced by the proposed exemption. The EDG loading and sequencing may change due to the elimination of the design requirement for the assumption of a concurrent LBLOCA/LOOP. Depending on the specific plant modifications implemented, it may be possible to automatically load additional systems on the EDGs, which would provide an overall reduced risk for events sequences associated with fires. LBLOCA/LOOP changes must be evaluated on a plant-specific basis to assure continued compliance with the requirements of Appendix R.

With respect to Item L.3 above, above, shutdown capability for specific fire areas is not reduced by the proposed exemption. The EDG loading sequencing may change due to the elimination of the design requirement for the assumption of a concurrent LBLOCA/LOOP. Depending on the specific plant modifications implemented, it may be possible to automatically load additional systems on the EDGs, which would provide additional capability for some fire areas.

3.1.4 Effect on Plant Safety Analysis

The proposed exemption would relocate the LBLOCA concurrent with a LOOP from the current design basis safety analysis to a beyond design basis accident category. All other safety analyses

in the current licensing basis (such as ATWS, SBO, etc.) would have to be reviewed for impact due to the implementation of the changes proposed in Section 2.4 of this LTR, not just those that are specific to LOCA and LOOP. This is required by the licensee's plant modification process, that implements the requirements of 10 CFR 50.54(a)(1) and Part 50 Appendix B (Quality Assurance), Criterion III for design control. Any such impacts would be evaluated for changes to the current safety analysis as required by 10 CFR 50.59 and any updates to the plant FSAR would be made pursuant to 10 CFR 50.71(e).

3.2 Defense-in-Depth

The change is consistent with the Defense-in-Depth strategy.

3.2.1 Regulatory Guidance

Regulatory Guide 1.174 (Reference 4, Section 2.2.1.1) – *Defense-in-depth* provides the guidance for defense-in-depth evaluations relative to changes in a plant-licensing basis. The guidance states:

The engineering evaluation should evaluate whether the impact of the proposed licensing basis change (individually and cumulatively) is consistent with the defense-in-depth philosophy. In this regard, the intent of the principle is to ensure that the philosophy of defense-in-depth is maintained, not to prevent changes in the way defense-in-depth is achieved. The defense-in-depth philosophy has traditionally been applied in reactor design and operation to provide multiple means to accomplish safety functions and prevent the release of radioactive material. It has been and continues to be an effective way to account for uncertainties in equipment and human performance. If a comprehensive risk analysis is done, it can be used to help determine the appropriate extent of defense-in-depth (e.g., balance among core damage prevention, containment failure, and consequence mitigation) to ensure protection of public health and safety. When a comprehensive risk analysis is not or cannot be done, traditional defense-in-depth considerations should be used or maintained to account for uncertainties. The evaluation should consider the intent of the general design criteria, national standards, and engineering principles such as the single failure criterion. Further, the evaluation should consider the impact of the proposed licensing basis change on barriers (both preventive and mitigative) to core damage, containment failure or bypass, and the balance among defense-in-depth attributes. As stated earlier, the licensee should select the engineering analysis techniques, whether quantitative or qualitative, traditional or probabilistic, appropriate to the proposed licensing basis change.

The licensee should assess whether the proposed licensing basis change meets the defense-in-depth principle. Defense-in-depth consists of a number of elements, as

summarized below. These elements can be used as guidelines for making that assessment. Other equivalent acceptance guidelines may also be used.

3.2.2 BWROG Approach

As stated in Section 2.0, the central approach to LBLOCA/LOOP has been to achieve an improvement in the overall risk balance between the risk increase assumed with the relaxation of the LBLOCA/LOOP provisions against the risk decreases that can be gained by optimizing the equipment performance for a broader spectrum of postulated events. The BWROG approach includes both risk analysis and best-estimate thermal-hydraulic evaluations. As demonstrated in Section 5, this improvement in the risk balance can be achieved, because as shown in Section 2.5, adequate mitigation capability remains for the LBLOCA/LOOP event after it has been reclassified from the design basis accident to a "mitigated beyond design basis accident" in the plant's licensing basis. That is, although the LBLOCA/LOOP event sequences are assumed to go to core damage in the risk assessment, in actuality, only a small subset of these sequences would actually be predicted to go to core damage. Thus, the enhancements proposed in Section 2.4 are evaluated against an artificially high threshold for being risk neutral.

3.2.3 Example Application - Defense-in-depth Evaluation

As stated in RG-1.174, consistency with the defense-in-depth philosophy can be maintained if certain conditions can be demonstrated. Each of these conditions is discussed in the following.

- A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation.
- This is demonstrated by the risk assessment in Section 5.1 and Appendix C and thermal-hydraulic analysis in Section 2.5 that demonstrates the overall plant risk of severe core damage can be reduced by the plant modifications that address the more probable postulated event sequences rather than the highly improbable concurrent LBLOCA/LOOP event.
- Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided.
- No weaknesses in the current plant design have been identified. The proposed changes sought by the proposed exemption allow a means of achieving a better overall balance of plant safety versus being skewed to a small subset of highly improbable events (i.e., LBLOCA/LOOP).
- System redundancy, independence, and diversity are preserved commensurate with the expected frequency and consequences of challenges to the system, and uncertainties (e.g., no risk outliers).

- There is no change in system redundancy, independence or diversity introduced by the proposed exemption. No mitigating systems are being physically removed from the plants. Only their design features are being revised to achieve optimal performance for the full spectrum of postulated events. The risk assessment in Section 5.1 and Appendix C provides a demonstration that an improvement in the overall risk of severe core damage can be achieved.
 - Defenses against potential common cause failures are preserved, and the potential for the introduction of new common cause failure mechanisms is assessed.
 - The possible plant modifications can be implemented consistent with the current plant defenses against common cause failures. Assessments of the plant modifications, consistent with established design practices under 10 CFR Part 50, Appendix B and §50.59, will be done to assure any potential new common cause failure mechanisms, although unlikely, are identified and dispositioned consistent with the plant's current design bases.
 - Independence of barriers is not degraded.
-
- In the BWR design there are five barriers to fission product release. These are:
 - Fuel Matrix
 - Fuel Cladding
 - Reactor Coolant Pressure Boundary
 - Primary Containment
 - Secondary Containment

During normal operation, approximately 10 – 20% of the noble gases and 2-3% of the halogens will migrate out of the fuel matrix into the gap region. The remainder is contained within the fuel matrix. The other non-gaseous, non-volatile fission products are maintained as an integral part of the fuel matrix. As a result, the fuel matrix is capable of retaining fission products until temperatures approaching the melting point of the fuel are reached. The thermal-hydraulic analyses, which are discussed in Section 2.5 and in Appendix B, indicate that the fuel cladding temperature during a LBLOCA/LOOP event with the proposed changes in Section 2.4, will not reach temperatures at which a substantial amount of the fission products in the fuel matrix would be assumed to be released. In this way, the fuel matrix continues to provide a substantial barrier to radioactivity release following a LOCA event.

The fuel cladding barrier may be breached if the cladding temperature reaches an excessive temperature. This current temperature limit below which excessive cladding failure is not expected is 2200°F (§50.46). Again, Section 2.5 and Appendix B demonstrate that, using realistic analysis assumptions, the peak cladding temperature remains within this limit. Thus, excessive cladding failure is not anticipated.

The reactor coolant pressure boundary is assumed to fail as a part of the LOCA definition. This assumption is consistent with the defense-in-depth approach to plant safety.

The primary containment boundary is assumed to fail if the primary containment design conditions (pressure and temperature) are exceeded. The primary containment performance will be consistent with the current safety analysis, as no changes to the pressure suppression capability are proposed by this exemption request. Therefore, the primary containment barrier will continue to perform acceptably after implementation of the proposed changes in Section 2.4.

The secondary containment is assumed to fail if the secondary containment design conditions (pressure and temperature) are exceeded. Because the proposed changes do not increase the challenge to the primary containment and no new primary containment bypass sequences are created, there is no change in the challenge to the secondary containment. Therefore, the secondary containment will continue to perform acceptably after implementation of the proposed changes.

Defenses against human errors are preserved.

As described in this LTR, the proposed exemption provides the opportunity to reduce the operator challenges. Some operator actions are eliminated (e.g., automatic alignment for SPC), while some new operator actions are added (e.g., manually starting a LPCS pump). However, these are routine operator actions, with reasonable mission times. Thus, the probability of human error is not changed from present.

The intent of the GDC in Appendix A to 10 CFR Part 50 is maintained.

The GDCs establish minimum requirements for the principal design criteria for light water reactors. The principal design criteria are intended to establish the necessary design, fabrication, construction, testing, and performance requirements for structures, systems, and components important to safety; that is, structures, systems, and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public.

The proposed exemption is to GDC 35, which has been interpreted as requiring consideration of a concurrent LBLOCA/LOOP. However, the risk assessment in Section 5 demonstrates a better

balance of plant safety is achievable if the design features that are focused on mitigating this event sequence are relaxed.

As described in Section 2.5, with implementation of the changes proposed in Section 2.4, reasonable assurance of the capability of the plant to mitigate LBLOCA accidents with a concurrent LOOP continues to be provided. This provides an additional layer of assurance that making these changes to a BWR is inherently consistent with the philosophy of defense-in-depth.

3.3 Safety Margins

The proposed change maintains sufficient safety margins.

Regulatory Guide 1.174 (Reference 4, Section 2.2.1.2) – *Safety Margins* provides the guidance for engineering evaluations relative to changes in a plant's licensing basis. The guidance states:

The engineering evaluation should assess whether the impact of the proposed licensing basis change is consistent with the principle that sufficient safety margins are maintained. Here also, the licensee is expected to choose the method of engineering analysis appropriate for evaluating whether sufficient safety margins would be maintained if the proposed licensing basis change were implemented. An acceptable set of guidelines for making that assessment is summarized below. Other equivalent acceptance guidelines may also be used. With sufficient safety margins:

- Codes and standards or their alternatives approved for use by the NRC are met.
- Safety analysis acceptance criteria in the licensing basis (e.g., FSAR, supporting analyses) are met, or proposed revisions provide sufficient margin to account for analysis and data uncertainty.

3.3.1 BWROG Approach

Safety margin for this discussion must be defined in the context of the deterministic safety analysis process. In the deterministic safety analysis process, the assumed plant events are analyzed using NRC approved methods. The results of these event analyses are compared to the applicable acceptance criteria. In the deterministic analysis process, the safety margin is inherent in the selection of the acceptance criteria and the conservatism in the approved methodology.

The acceptance criteria are selected such that there is considerable margin to the expected barrier failure. Generally, the safety margin applied is incrementally proportional to the expected frequency of occurrence. That is, the more likely the event occurrence, the more safety margin is applied. The acceptance criteria used in the safety analysis process are identified in the plant's licensing basis and generally cannot be changed without prior NRC approval. The conservatism

in an event's safety analysis methodology is consistent with the category/type (e.g., anticipated operational occurrence (AOO) or Design Basis Accident (DBA)).

3.3.2 Safety Margin Assessment

The exemption request proposes the relocation of the assumption of a concurrent LBLOCA/LOOP from DBA category to the "beyond design basis accident" category. Thus, consistent with the above philosophy for such a change in event frequency, the incremental safety margin can be lower and less conservatism in the methodology can be utilized for a beyond design basis accident than for a DBA.

In the thermal-hydraulic analysis of the LBLOCA/LOOP changes, the acceptance criterion to be applied for a beyond design basis accident was chosen to be retaining the fuel in a "coolable geometry." Because defining a specific set of conditions that characterize a "coolable geometry" for the fuel is problematic, a surrogate criterion using the current acceptance criteria of §50.46 was proposed; specifically, 2200 °F for peak clad temperature and 17% local clad oxidation fraction. Use of these surrogates inherently provides safety margin in the final results.

In addition, a "best-estimate" thermal-hydraulic methodology is proposed instead of that required by the regulations (§50.46 and 10 CFR Part 50, App. K) for design basis accidents. Again, this is in keeping with the lower frequency event category of a beyond design basis accident. While a "best-estimate" model was used for the example, it contains sufficient conservatisms, as described in Appendix B of this report, to provide for the uncertainties in the analysis.

Application of the above approach ensures that sufficient safety margins are preserved with the implementation of the proposed changes, consistent with the RG 1.174 guidelines.

3.4 Risk Increases are Small

3.4.1 The change Results in a small or no increase in risk consistent with NRC safety goals.

In the LBLOCA/LOOP analysis, the overall impact of the change is assessed and compared to the quantitative risk acceptance guidelines of RG 1.174, which is consistent with the intent of the Commission's Safety Goal Policy Statement. It should be noted that a generic risk assessment was carried out for these modifications and the results showed a decrease in CDF for all but one of the modifications. The results of the generic risk assessment are documented in Appendix C and summarized in Section 5.

As noted earlier, conservatively, in the risk analysis, the LBLOCA/LOOP event is assumed to go straight to core damage. Therefore, the LBLOCA/LOOP frequency is the same as the CDF. If this frequency is greater than 1.0E-6/year, the exemption is not permitted. Most of the proposed plant modifications are expected to reduce the core damage risk. Therefore, if it can be qualitatively determined that a proposed modification reduces the CDF, then no quantitative

analysis is required. Otherwise, quantitative risk assessment is needed. Two types of effects on CDF and LERF are considered. The first effect involves the total or aggregate risk impact for all PRA events for each individual LBLOCA/LOOP change. The second effect involves the cumulative risk impact from the selected combination of LBLOCA/LOOP changes. More detail is provided in subsequent paragraphs that describe the overall process. The PRA used to support this change will, at a minimum, address CDF and LERF for power operation. Generic discussions of the impact on risk from external events are provided in Appendix C, Section C.3.6. For the purposes of this application, shutdown events are not included because the LBLOCA with a consequential LOOP is not credible from the shutdown condition.

NRC RG 1.200 addresses technical adequacy of PRA for risk-informed applications. This regulatory guide will be followed for plants proposing to implement LBLOCA/LOOP changes.

3.5 Monitoring the Changes

3.5.1 Use Performance-Monitoring Strategies to Monitor the change

A performance monitoring strategy will be developed to provide confidence that the equipment performance is consistent with the considerations of the overall LBLOCA/LOOP process, and is not degrading such that the analysis assumptions and any expert panel judgments are no longer valid. It is expected that in most cases, the existing performance monitoring required by the Maintenance Rule or MSPI would be adequate. The output of the performance monitoring will be periodically re-assessed, and appropriate adjustments made to the analysis of the risk impact of LBLOCA/LOOP changes.

4.0 PROCESS FOR MAKING LBLOCA/LOOP CHANGES

This section describes the process that each licensee must follow for preparing the LBLOCA/LOOP exemption request. The process includes both a probabilistic as well as a deterministic evaluation, as outlined in RG 1.174. The process is broken down into 24 steps as shown in Figure 4-1. Each step is described in detail in this section.

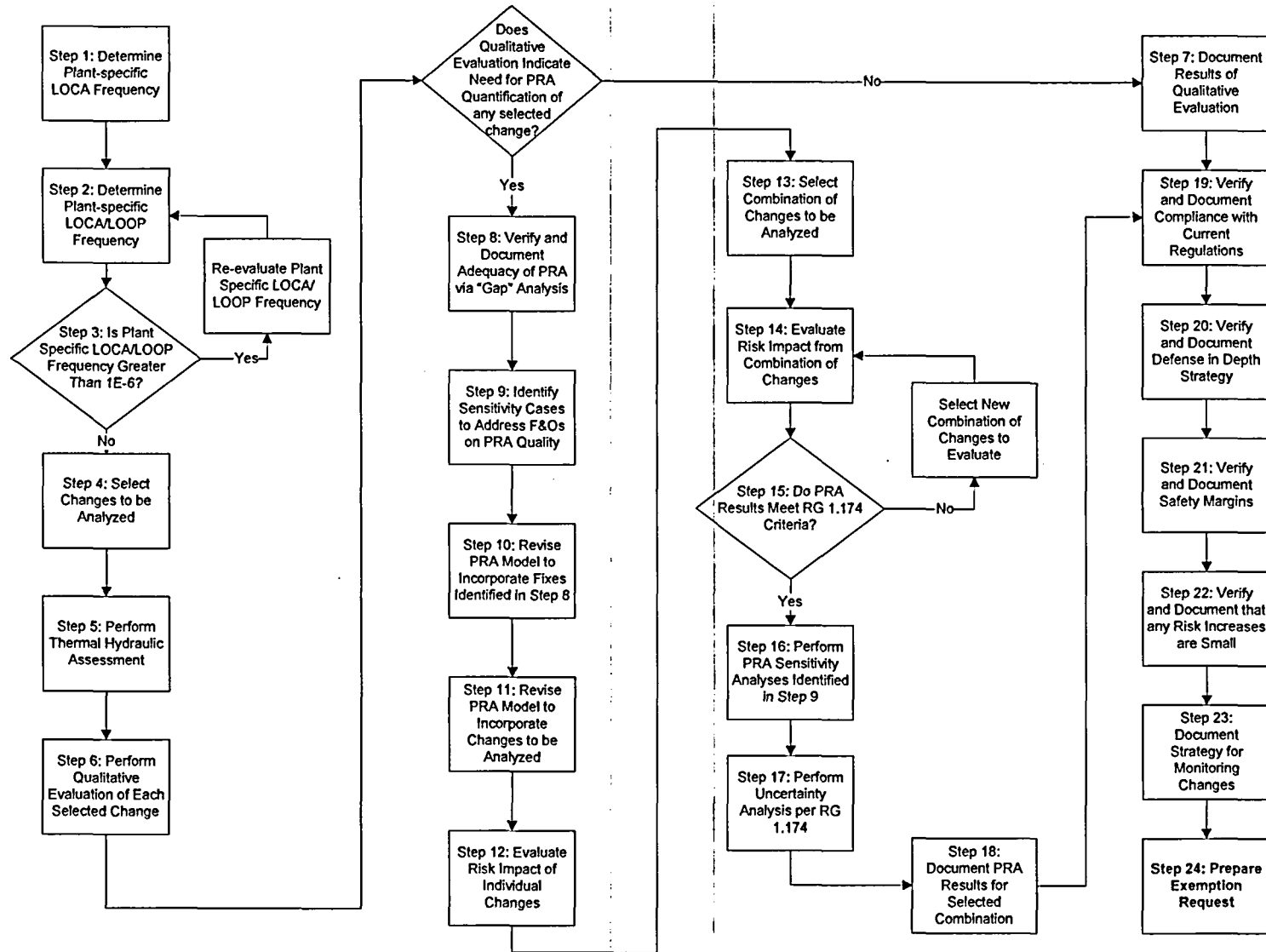


Figure 4-1 Flow Chart of Process Steps

4.1 Step 1: Determine Plant-Specific LBLOCA Frequency

In this step, the frequency of LBLOCA is evaluated for the licensee's plant-specific PRA.

The probabilistic risk effect of eliminating a large break LOCA concurrent with a loss-of-offsite power as a design consideration is addressed in this section. As indicated earlier, an increase in the calculated core damage frequency (CDF) occurs because the LBLOCA/LOOP contribution is assumed to equal the initiating event probability, i.e., no credit is allowed for mitigation.

However, most of the proposed modifications are expected to better mitigate the remaining PRA accident sequences and therefore reduce the CDF. The improved mitigation is primarily due to increased emergency diesel availability and ECCS logic changes.

The changes proposed do not affect the entire range of LBLOCA events. The lower end of the large LOCA break sizes and any LOCAs involving breaks above the core (i.e. steam line breaks) or SORVs would not be significantly affected by the changes described in Section 2.4.

A study representing the latest effort to develop LOCA frequencies is documented in Reference 13. This study was sponsored by the NRC to provide updated frequencies for LOCAs, across the range of possible break sizes. The study received input from a number of experts and through a consensus process arrived at the uncertainty distributions for LOCAs of various sizes provided in Table 4-1 for the current average plant age of 25 years. Table 4-2 provides similar frequency distributions for a plant near the end of its 40-year license.

If the LOCA frequency developed in Reference 13 is to be used for the exemption request resulting from this analysis, the values provided in Table 4-2 should be used, so that the frequencies will be applicable to any plant throughout its 40-year life span. In addition, it is recommended that the frequency for a break size >25,000 gpm (7" effective break size) be used since it will encompass breaks larger than 7" including 10" breaks, for which the generic thermal-hydraulic analysis was performed.

**Table 4-1 Current Estimate of LOCA Frequencies for
Plants with an Average of 25 Years Operating Experience (Reference 13)**

LOCA Size (gpm)	EFFECTIVE BREAK SIZE (IN.)	Total BWR LOCA Frequencies (per calendar year)			
		5 th Percentile	Median	Mean	95 th Percentile
>5,000	3.25	7.4E-7	9.7E-6	2.4E-5	7.9E-5
>25,000	7	1.2E-7	2.2E-6	6.1E-6	2.0E-5
>100,000	18	1.2E-8	2.9E-7	1.1E-6	3.7E-6
>500,000	41	9.7E-12	3.0E-10	3.2E-9	7.7E-9

Table 4-2
Estimate of LOCA Frequencies for Plants at End of 40-Year Plant License (Reference 13)

LOCA Size (gpm)	EFFECTIVE BREAK SIZE (IN.)	Total BWR LOCA Frequencies (per calendar year)			
		5 th Percentile	Median	Mean	95 th Percentile
>5,000	3.25	6.7E-7	9.8E-6	2.7E-5	8.8E-5
>25,000	7	1.1E-7	2.3E-6	7.6E-6	2.4E-5
>100,000	18	1.1E-8	3.1E-7	1.5E-6	4.6E-6
>500,000	41	1.2E-11	4.0E-10	4.9E-9	1.1E-8

Alternately, the Large Break LOCA frequency provided in NUREG/CR-5750 (Reference 7) can be used. NUREG/CR-5750 develops BWR LBLOCA frequencies by analyzing data for throughwall cracks in piping and multiplying the crack frequency by an estimate of the conditional probability of rupture given a crack and a scaling factor to account for improvements in detecting and preventing pipe cracks caused by IGSCC. Table 4-3 provides the uncertainty distribution parameters for the Large Break LOCA frequency developed in Reference 7.

Table 4-3
BWR Large Break LOCA Frequency from Reference 7

Mean	Lower Bound	95 th Percentile
2.4E-5	9E-7	9E-5

A refinement to the LOCA frequencies provided in NUREG/CR-5750 (Reference 7), using expert elicitation, is described in Section 4.2 of Reference 15. The expert elicitation described in Reference 15 resulted in a LBLOCA frequency for BWRs that was a little more than a factor of 2 higher than the frequency developed in NUREG/CR-5750. However, the LOCA frequencies described in Reference 15 have been superseded by the LOCA frequencies developed by expert elicitation in Reference 13 and provided in Tables 4-1 and 4-2.

Some PRA models may be using LOCA frequencies derived from earlier sources, such as NUREG-1150 or WASH-1400. If licensee's PRA model uses LOCA frequencies from one of these sources, the licensee should consider revising the PRA model to use one of the more recent sources of LOCA frequency to make the exemption justification more consistent.

After the LOCA frequency determination, proceed to Step 2.

4.2 Step 2: Determine Plant-Specific LOCA/LOOP Frequency

In this step, the plant-specific value is evaluated for the conditional probability of LOOP given a large LOCA.

Once the frequency of LBLOCA has been determined (Step 1), it is necessary to determine the conditional probability of LOOP given a LBLOCA to calculate the frequency of LBLOCA/LOOP. Both the NRC and the industry have provided estimates of the frequency of LBLOCA (Tables 4-1, 4-2, and 4-3) and the probability of a LOOP given a LBLOCA (Table 4-4). The product of these numbers gives the LBLOCA/LOOP frequency.

Previous estimates of the generic conditional probability of LOOP given LOCA are presented in Reference 10, which uses expert elicitation to develop the LOOP given LOCA probability and Reference 14, that uses data analysis from a small number of events. The Reference 10 report prepared by EPRI has not been formally issued.

Reference 15 represents the development of the generic probability of LOOP given LOCA, by modeling the component failures and human errors that could lead to a LOOP following a LOCA. This NRC sponsored study develops a conditional probability of LOOP given LOCA using a fault tree analysis. This study recognizes that there are two contributors to the conditional probability of LOOP given a LOCA, namely, plant-centered and grid-centered events. The plant-centered event value is calculated with the help of a fault tree. The grid-centered event value is judged to be smaller than the plant-centered event probability (see following paragraph). Therefore, the conditional probability of LOOP given LBLOCA due to both grid-centered and plant-centered events is conservatively calculated by doubling the plant-centered event probability that is calculated with the help of a fault tree.

Section G.4.2 of Reference 15 provides the basis for concluding that the probability of grid-centered events is less than the plant-centered events. The basis for this conclusion is summarized below.

1. There have been more consequential LOOPS due to plant-centered factors than due to grid-related factors. The events are listed in Table G.5 of the reference.
2. The data on LOOP events in NUREG/CR-5496 (Reference 19) indicates that there are more LOOP events due to plant-centered failures than due to grid-related failures. There are 65 LOOP events due to plant-centered failures and 6 events due to grid-related failures. In other words, the number of events due to plant-centered failures is about one order of magnitude larger than the number of events due to grid-related failures. The NUREG authors conclude: “..Based on this experience, grid instability has not been an important contributor to [LOOP] frequency.”

Generally, two configurations exist for supplying power to the safety buses during normal operation. One supplies power from the main generator through an auxiliary transformer, the second supplies power from the offsite grid through a startup transformer. The contribution to the conditional probability of LOOP given a LBLOCA from plant-centered factors is slightly different for the two configurations. Table 4-4 provides, for these configurations, the mean value and the uncertainty distribution parameters for the conditional probability of LOOP given LOCA as developed in Reference 15.

Table 4-4 Conditional Probability of LOOP Given LOCA*

Power supply during normal operation	Probability		
	5 th Percentile	Mean	95 th Percentile
Main generator thru auxiliary transformer	1.1E-2	2.4E-2	4.6E-2
Offsite power thru startup transformer	8.6E-3	2.1E-2	4.3E-2

Licenses can use the values in Table 4-4 as the source of the probability of LOOP given LBLOCA. Alternatively, licensees wishing to calculate a plant-specific probability of LOOP given LBLOCA, should use the methodology described in Appendix G of Reference 15, considering plant-specific design features and plant-specific failure rate data. This recommendation is especially useful for plants with multiple switchyards and multiple offsite power sources, since the values in Table 4-4 may be too conservative for this switchyard configuration. An example of the fault tree method from Appendix G of Reference 15 is provided in Appendix E of this report.

Double Sequencing: One subset of the LOOP events, those involving double sequencing, deserves some discussion. The double sequencing event is described in Section 2.2 "BWROG Approach". Double sequencing would most likely occur if there were a concurrent LOCA, with its associated plant trip, and a prior stressed transmission grid condition. Based upon published studies by EPRI and NRC, the BWROG does not believe that such double sequencing events create greater consequences than assumed in this LTR for both PRA and T/H evaluations. To ensure that the problem is bounded, the BWROG has conservatively assumed that all delayed LBLOCA/ LOOP sequences go directly to core damage in the PRA evaluation. This approach is very conservative and makes the double sequencing issue a moot point from the core damage risk point of view.

* From Reference 15, Table 4.3.

Example

The frequency of LOCA/LOOP is calculated by combining the LOCA frequency selected in Step 1 with the conditional probability of LOOP given a LOCA from Table 4-4. For example, selecting the frequency of a break with a leak rate greater than 25,000 gpm at a plant near the end of its 40 year license yields a LOCA frequency of $7.6\text{E-}6$ per year. Combining this frequency with the conditional probability of LOOP given LOCA from Table 4-4 for the main generator/auxiliary transformer configuration ($2.4\text{E-}2$) yields a mean LOCA/LOOP frequency of $1.8\text{E-}7$ per year.

If the LBLOCA frequency from NUREG/CR-5750 (Reference 7) is used instead in Step 1, combining this frequency with the same conditional probability of LOOP given LOCA would yield a mean LOCA/LOOP frequency of $5.8\text{E-}7$ per year.

The generic example analysis of Appendix C, using data available at the time, estimated the range of LBLOCA/LOOP frequencies to be between $3.0\text{E-}7$ and $1.2\text{E-}6$ per year (References 7, 10, 13). The Appendix C example assumes a conservative mean value of $1.0\text{E-}6$ per year as the increase in CDF associated with the deterministic elimination of the capability to mitigate a concurrent LBLOCA and LOOP.

After evaluating the LOCA/LOOP frequency, proceed to Step 3.

4.3 Step 3: Decision Point, Is LBLOCA/LOOP Frequency Greater Than $1\text{E-}6$?

In the earlier steps, the LBLOCA/LOOP frequency was calculated. In this LTR, the LBLOCA/LOOP event is assumed to directly lead to core damage. RG 1.174 permits small increases in risk for risk-informed applications. An increase in core damage frequency, CDF, of $1.0\text{E-}6$ per year is considered to be small increase per RG 1.174.

In this step, the LBLOCA/LOOP value is compared to the RG 1.174 value of $1.0\text{E-}6$ /year. If the value is greater than $1.0\text{E-}6$, there are two options. One option is to proceed no further and abandon the development of a LBLOCA/LOOP exemption request. The second option is to reevaluate the LBLOCA frequency and select one of the LBLOCA frequencies described in Step 2, to be used in licensee's PRA model. If the second option is chosen, select the LBLOCA frequency that is most applicable to licensee's plant and PRA model and return to Step 2.

Strictly speaking, the LERF values should also be checked against an acceptable limit of $1.0\text{E-}7$ /year. However, for BWR PRAs, the conditional probability of large early release given a core damage following a LOCA is about $1.0\text{E-}2$, and this makes this check for the LERF criterion unnecessary. If the CDF value is below the acceptance limit of $1.0\text{E-}6$, then the LERF value can be no greater than $1.0\text{E-}8$, which is well below the LERF acceptance limit.

If the plant-specific LBLOCA/LOOP frequency is less than $1.0\text{E-}6$ /year, then proceed to Step 4.

4.4 Step 4: Select Changes to be Analyzed

In this step, the licensee selects the plant modifications to be analyzed for possible implementation as part of this exemption request.

First, the licensee reviews the changes described in Section 2.4 to determine which changes are applicable to his plant and, among those, which should be included in the LBLOCA/LOOP exemption request. A prioritization of changes for each plant configuration is provided in Table 4-5. The priority rank (1, 2 or 3 with 1 being the highest rank) is assigned based on the risk reduction (decrease in CDF) calculated from the generic PRA model, for changes that are applicable to the specific plant configuration. This prioritization provides some additional information that may be useful when selecting changes to analyze.

Note that the first two changes listed, “Disabling LPCS Automatic Start Following LOOP” and “Disabling 2 of 4 LPCI Automatic Start Following LOOP” are two different options within the change labeled “Optimize EDG Loading” described in Section 2.4.1. Only one of these two options can be implemented. In Table 4-5, if a specific plant configuration has a priority rank assigned to only one of these two options, it means that the ranked option showed a greater risk reduction in the generic PRA model. If priority ranks are assigned to both options, it means that they resulted in equal risk reductions using the generic PRA model. In either case, the licensee should evaluate both options using its plant-specific PRA model to determine the optimum choice.

Table 4-5 Prioritization of Changes Based on Risk Reduction

Change	Plant Configuration							
	BWR 3/4	:WR 3/4 with AC Independent P Injection	:WR 3/4 with Independent AC over Source	BWR 5/6	:WR 5/6 with AC Independent P Injection	:WR 5/6 with Independent AC over Source	:WR 3/4 with LPCI Loop- elect and AC Independent LP Injection	:WR 3/4 with LPCI Loop- elect and Independent AC over Source
Disabling LPCS Automatic Start Following LOOP	*	1*	*	2*	1*	*	*	*
Disabling 2 of 4 LPCI Automatic Start Following LOOP	2*	1*	2*	2*	1*	2*	1*	2*
One Loop of RHR in SPC Mode	1	2	1	1	2	1	2	1
Eliminating LPCI Loop-Select	N/A	N/A	N/A	N/A	N/A	N/A	3**	3**

* Only one of the options shown can be implemented. Either the LPCS pumps or 2 of 4 LPCI pumps can be removed from auto-loading onto the EDGs, but not both. (*All single asterisks have the same footnote information*)

** This change resulted in a small increase in risk in the generic PRA model (see Appendix C).

The other changes described in Section 2.4, not listed in Table 4-5, were addressed qualitatively in the generic example of Appendix C and are all deemed to result in risk reductions or no change in risk. If any of these other changes are selected for evaluation, they should be addressed qualitatively, since they are difficult to quantify.

Some of the changes described in Section 2.4 are mutually exclusive and cannot be implemented together. These mutually exclusive changes are as follows:

- For the change “Optimize EDG Loading” either 2 LPCI pumps or the LPCS system are removed from automatic loading onto the EDGs, but not both. Removing 2 LPCI pumps and the LPCS system from automatic loading onto the EDGs would significantly reduce the redundancy of low pressure injection sources, without operator actions to realign pump power supplies.
- The changes “Optimize EDG Loading” and “One Loop of RHR in SPC Mode” cannot both be implemented together. Aligning one loop of RHR in SPC mode and removing 2 LPCI pumps or the LPCS system from automatic loading onto the EDGs would significantly reduce the redundancy of low pressure injection sources, without operator actions to realign pump power supplies.
- The changes “Eliminate LPCI Loop-Select” and “One Loop of RHR in SPC Mode” cannot both be implemented together. If loop “A” of RHR is aligned in SPC mode and a break occurs in Core Spray line “A”, single failure criteria could not be met (for example, failure of train “B” 125V DC would result in no ECCS, without operator actions to realign the RHR loop).

4.5 Step 5: Perform Thermal-Hydraulic Assessment

Step 5 addresses the need for performing thermal-hydraulic assessments. The generic thermal-hydraulic analyses performed in the benchmark and sensitivity analyses in this LTR evaluated the impact of plant variability with respect to RCS volume, available ECCS injection systems, ECCS injection flow rate and the timing of ECCS injection.

The assumptions in Table 2-3 need to be validated by each licensee seeking an exemption to ensure that the analyses in this report are applicable to his plant. The RPV volume variability sensitivity analyses (Appendix B, Section B.6.3) encompassed a wide enough range to preclude the need for further validation.

The minimum system availability requirements, shown in Table 2-3, are needed to preserve the defense-in-depth. In this way, a LBLOCA with an assumed LOOP must have at least this minimum set of ECCS available for injection within the assumed time delay interval, in order to conform to the assumptions of the analyses performed in Appendix B.

If the licensee determines that each of the parameters for his plant are enveloped by the values used in the generic analysis, then no MAAP analysis need be performed for demonstrating that the LBLOCA can be mitigated. The results of the appropriate generic MAAP analysis will apply to the licensee's plant, and as demonstrated for the generic analysis, the results are acceptable.

If licensee determines an inability to satisfy the requirements in Table 2-3, then plant-specific MAAP analyses must be performed. The licensee should first modify the base case MAAP4 inputs to represent their plant. This would involve executing a similar LOCA analysis using a plant-specific MAAP4 parameter file. Similar assumptions regarding the core nodalization and injection delay times should be employed as described in Appendix B. These assumptions include:

- Representation of the hot channel as described in Appendix B, Section B.4.2.1
- Account for the time to refill the recirculation loop by a delay in LPCI injection as described in Section B.4.2.1

Sample MAAP4 input files will be provided upon request to allow the applicant to create a plant-specific analysis similar to that described in Appendix B.

If the plant-specific MAAP4 analysis results show a PCT at or below the Appendix B result, then the plant should simply document their evaluation and show how they relate to the results from Appendix B. If the PCT from their plant-specific MAAP4 analysis shows a value greater than the generic MAAP4 result from Appendix B, then a plant-specific analysis using TRACG04 or later should be performed to show that the calculated PCT results are within the existing 10 CFR 50.46 acceptance criteria of 2200 °F and 17% cladding oxidation.

4.6 Step 6: Perform Qualitative Evaluation of Each Selected Change

In this step, for each proposed plant modification, a qualitative evaluation is made to determine if the modification is risk beneficial or risk neutral. If so, in subsequent steps, a quantitative PRA evaluation would not be required.

The licensee should then evaluate the selected changes qualitatively by answering the following questions:

- Can the failure of the proposed modification contribute to an initiating event?
- Does the proposed modification increase the unreliability of the system it is part of?
- If the modification is part of a support system, does the proposed modification increase the unreliability of the system it is supporting?

- Does the proposed modification increase the unreliability of any needed operator action modeled in the PRA?
- Is the proposed modification expected to result in an increase in risk as measured by CDF and LERF?

If the answers to all of these questions are “No”, proceed to Step 7. If the answer to any of these questions is “Yes”, skip to Step 8. Note that this step may result in following two different paths through subsequent steps. This step is performed separately for each selected change, such that one or more changes may proceed to Step 7 while at the same time one or more changes may skip to Step 8.

It is expected that the following changes can be addressed by a qualitative evaluation alone, in some cases supported by thermal-hydraulic analysis, and will not require a PRA analysis:

- *Allow EDG Warm up Prior to Loading* – This change delays the application of loads onto the EDG, following a cold start. Thermal-hydraulic analysis and a qualitative evaluation can be used to show that this change results in a decrease or no change in plant risk. However, if the licensee chooses to perform a PRA quantification of this change, a method for estimating the improvement in EDG reliability resulting from this change is described in Step 11.
- *Start EDGs Only When Needed* – This change removes the LOCA start signal from the EDG start logic; EDGs would start only on an actual undervoltage signal. EDG start signals are not normally modeled in PRAs since the probability of the failure of a start signal is so much lower than the probability of failure to start of an EDG. In addition, operators would not need to secure unneeded EDGs following a LOCA signal with no undervoltage. A qualitative evaluation can be used to show that this change results in a decrease or no change in plant risk.

If the licensee chooses to quantify the change in operator action failure rates, the licensee would first review its PRA model to determine which operator actions might be impacted by a reduction in operator burden. An initial list of operator actions to consider can be assembled by collecting all operator actions with a Fussell-Vesely importance greater than $1.0E-3$. This list can be screened to reduce the list to actions that could be impacted by the LBLOCA/LOOP change. The human reliability analysis (HRA) could then be reevaluated for the selected actions and the revised HRA values input to the PRA model. If revising the HRA results is not practical, the licensee could convene an expert panel of PRA personnel and plant operations personnel and develop a consensus for any revisions to HRA values resulting from the LBLOCA/LOOP change.

- *Simplified EDG Testing* – This change simplifies the success criteria and procedures for testing EDGs. A qualitative evaluation can be used to show that this change results in a decrease or no change in plant risk. There is nothing to be revised in the PRA model related to this change.
- *Increased MOV Stroke Times* - This change extends the time available for the ECCS MOVs to stroke. This could allow using smaller valve operators and at a minimum would change the MOV stroke test success criteria to be less restrictive, resulting in fewer artificially induced test failures and fewer valve maintenance events. If a licensee chooses to make this change, the licensee would review the relevant maintenance data and determine which MOVs have disproportionate preventive or corrective maintenance associated with preserving a stroke time that is artificially short due to the current LBLOCA-LOOP requirement. Each plant seeking this relaxation will need to demonstrate that the relaxed MOV stroke times will continue to meet the current regulatory limits. Thermal-hydraulic analysis and a qualitative evaluation can be used to show that this change results in no change in plant risk. There is nothing to be revised in the PRA model related to this change.

Generic discussions of the impact on risk from external events are provided in Section 2.2 and Appendix C, Section C.3.6. These discussions should be reviewed and revised as needed and included in the exemption request.

4.7 Step 7: Document Results of Qualitative Evaluation

For each selected change, the licensee should document the results of the qualitative evaluation performed in Step 6, providing any supporting information or risk insights related to the selected change. This documentation will serve as the basis for not performing PRA analysis of the selected change. Any changes selected for implementation that are addressed qualitatively here and have an impact on the PRA model are to be reflected in the licensee's next scheduled PRA update.

4.8 Step 8: Verify and Document Adequacy of PRA

Step 8 is entered from Step 6, if for certain proposed modifications, based on a qualitative evaluation, it cannot be concluded that the modification is risk-beneficial or risk-neutral. In such a case, the plant modification has to be evaluated with the help of the plant PRA. Prior to using the PRA, its quality has to be established and that is the purpose of Step 8.

The adequacy of the licensee's PRA should be determined using the method described in Section 2.3. Any "gaps" in the PRA will be categorized into one of three categories:

1. Has no impact on risk assessment of selected changes, or
2. Sensitivity cases need to be run to evaluate the impact on the LBLOCA/LOOP changes, or
3. Needs to be addressed prior to using PRA model for LBLOCA/LOOP analysis.

If any “gaps” exist that fall into the third category, they should be addressed and any PRA model changes made prior to using the PRA model for quantification of risk impacts.

4.9 Step 9: Identify Sensitivity Cases to Address “Gaps” in PRA Quality

Step 9 is a continuation of activities identified in Step 8.

If any “gaps” are identified in Step 8 that fall into the second category, a sensitivity case should be defined to address each Category 2 “gap”.

Example

For example, assume there is an outstanding F&O (significance level “B”) related to the failure frequency of RHR pumps used in the PRA model not being plant-specific. A sensitivity case could be defined that develops and uses plant-specific failure rates for the RHR pumps. If the development of plant-specific failure rates is not practical for this exemption request, a sensitivity case might be defined that uses conservative, bounding values for the failure rates to assess the possible impact of these failure rates on the quantification of selected changes.

4.10 Step 10: Revise the PRA Model to Incorporate PRA Model Enhancements

If any “gaps” are identified in Step 8 that fall into the third category, they should be addressed and any PRA model changes made prior to continuing to the next step.

Example

For example, assume there is an outstanding F&O (significance level “A”) related to the omission of common cause failures for the RHR pumps in the PRA model. Common cause failures of the RHR pumps would be incorporated into the PRA model in this step to ensure that the PRA model is adequate for the quantification of the risk impact of selected changes.

4.11 Step 11: Revise the PRA Model to Incorporate the Changes to be Analyzed

---Prior to reaching Step 11, the plant PRA would have been upgraded to bring it to the right quality level. In Step 11, the plant PRA model is changed to incorporate each of the proposed modifications that require PRA analysis.

First, the licensee should take note of the current CDF and LERF values from the “Base Case” or unaltered PRA model. These values will be used to calculate the risk increase or decrease resulting from each of the selected changes and the selected combination of changes.

The following describes the PRA model revisions necessary to quantify the indicated change from Section 2.4.

Optimize EDG Loading

In the description of the changes, it was postulated that either LPCS or some LPCI pumps could be eliminated as equipment that is automatically loaded on to the diesel generators, while battery chargers could be added. This provides a trade-off. If the chargers are automatically loaded on the emergency buses, the operator actions associated with DC load shed or re-start of the chargers would be rendered unnecessary. Low pressure ECCS pumps that are not automatically loaded following a loss-of-offsite power could be subsequently added manually in the event that other systems were unable to provide adequate core injection.

Each plant should determine the proper loads and loading sequence from PRA dominant sequences, equipment importance measures, and operator action importance measures related to manual loading of post-transient equipment, and consistency with existing plant operating and emergency procedures. Plants implementing this change should insure that their loading sequence is within the capability of the EDGs.

Example

The PRA model should be modified to address the proposed configuration. In this example, the 125 V DC model is changed such that if offsite power were lost, the operator action to load the chargers would be eliminated from the model. Two cases are considered. In one case, the licensee can change the LPCS fault tree model by adding an operator action to manually start these pumps following a loss of offsite power. In the second case, he can change the LCPI fault tree model in a similar manner, but include the operator action for only two of the four LPCI pumps.

One RHR Loop in SPC Mode

Another postulated change is to start one loop of RHR in suppression pool cooling mode rather than LPCI mode. With this change, the operators would not need to start suppression pool cooling for scenarios in which the pool water temperature increased above a given value. If the other core injection sources are not available, the RHR loop selected for automatic SPC could be manually aligned to the LPCI mode instead.

Example

In the PRA model, eliminating the operator action for aligning one loop of RHR into suppression pool cooling simulates this change. An operator action to manually start the loop in LPCI mode is added to the LPCI model for that loop. The other loop retains the original configuration. If the operator action to align for suppression pool cooling is not applied at the loop level in the

existing fault tree, the operator action basic event should be relocated to the level of a single loop of RHR in order to make this change possible.

Eliminate LPCI Loop-Select

This option is applicable only for certain BWR 4 plants. In the past, LPCI Loop-Select has been removed from BWRs through elaborate redesign and reconfiguration. The change proposed here is to eliminate the feature in a straightforward manner. The crosstie valve would be locked closed, and the logic would be disabled.

Example

In the PRA model, eliminating the loop select logic involves not only removing any basic events related to the generation of a loop select logic signal, but could also involve revising the Large LOCA initiating event(s). If a single initiating event is included in the PRA model for Large Break LOCAs, it should be split into two initiating events, one for Large LOCAs in recirculation line A and one for Large LOCAs in recirculation line B, i.e., in effect, two event trees would be developed in place of one. The original total Large LOCA frequency can be divided equally between the two new initiating events. Also, no credit should be taken in the PRA model for providing LPCI injection from Loop A pumps through the Loop B injection path or vice versa, since the crosstie valve will now be locked closed.

Allow EDG Warm Up Prior to Loading

It is expected that a PRA evaluation of this modification would not be required. However, if it is required, the following procedure should be used.

The start time is typically on the order of 10 seconds and is referred to as a "fast start". The requirement for fast start tends to incrementally decrease the reliability of the EDGs due to the component degradation associated with operating the equipment in this manner.

If the requirement for fast start were eliminated, the EDG starting circuits could be modified to allow an interval of warm up at idle speed before accelerating the engine to full speed and loading the bus. Diesel generator engineers at BWROG member plants have indicated that any warm up time would be beneficial, but 30 seconds to a minute warm up duration is expected to yield incremental reliability benefits. A proposed method for quantifying the incremental benefit to EDG reliability is described in the example that follows.

Example

Diesel generator unreliability in PRA models is generally made up of three parts, failures to start, failures to run, and maintenance unavailability. The failures to run are sometimes broken down into failures to run during the first hour of operation and failures to run after the first hour. A

review of EDG failure events in NUREG/CR-5500 vol.5 (Reference 17) "Reliability Study: Emergency Diesel Generator Power System, 1987-1993," Table 2 and Table B-5 resulting from cyclic tests yielded no "fail to start" events attributable to EDG mechanical failures. Since there is insufficient data to support an improvement in failure to start due to a reduction in the number of fast starts, no improvement in the failure rate for failure to start is assumed. Detailed data concerning maintenance events was not available and no improvement in maintenance unavailability was also assumed, even though it is expected that there would be some improvement. The review also yielded 7 of 27 "fail to run" events attributable to EDG mechanical failures. If it is assumed that one of these mechanical events can be affected by a reduction in the number of EDG fast starts and this assumption is applied to the more recent EDG failure rates provided in NUREG/CR-6890 vol.2, a lower bound EDG reliability improvement of approximately 1.3% can be calculated for a mission time of 6 hours. If it is assumed that all 7 of these mechanical events can be affected by a reduction in the number of EDG fast starts and this assumption is applied to the same base failure rates, an upper bound EDG reliability improvement of approximately 8.9% can be calculated for a mission time of 6 hours. If it is assumed that half of these mechanical events can be affected by a reduction in the number of EDG fast starts and this assumption is applied to the same base failure rates, a best-estimate EDG reliability improvement of approximately 4.5% can be calculated for a mission time of 6 hours. Longer mission times, for example 8 hours or 24 hours, produce even larger improvements in diesel reliability, as high as 16.1% for a 24 hour mission time, assuming all 7 mechanical events can be impacted by reducing the number of fast starts. These estimates do not take credit for any improvement in EDG maintenance unavailability that would most probably result from a reduction in the number of fast starts.

4.12 Step 12: Evaluate Risk Impact of Individual Changes

The risk impact resulting from each change is evaluated using the following five sub-steps:

- (a) Calculate the CDF and LERF for the base (unaltered) case. The base case PRA model is the plant PRA model prior to making any LBLOCA/LOOP changes described in Step 4 and should not include the assumption that LBLOCA/LOOP goes directly to core damage.
- (b) Calculate the CDF and LERF following the change. Quantify the PRA model with the revisions to the model described in Step 5 for the LBLOCA/LOOP change.
- (c) Delete any contribution from LBLOCA/LOOP to the revised CDF and LERF calculated in (b). Since the assumption that LBLOCA with LOOP goes directly to core damage is not included in the "Base Case" model, step (c) is needed to remove the contribution from LBLOCA with LOOP that exists in the Step (b)

model, but does not exist in the base case (Step (a)) model to calculate an accurate change in risk resulting from the LBLOCA/LOOP change.

- (d) Subtract the CDF results of (a) from (c). This represents the CDF improvements caused by the change that offsets a portion of the CDF increase associated with eliminating the LBLOCA/LOOP requirement
- (e) Subtract the LERF results of (a) from (c). This represents the LERF improvements caused by the change that offsets a portion of the LERF increase associated with eliminating the LBLOCA/LOOP requirement

Example

The quantification of the risk impact, using the generic BWR PRA model, for each of the changes described in Section 2.4 is described in Section C.5 of Appendix C. The risk impact results of each LBLOCA/LOOP change for eight different BWR plant configurations are provided in Sections C.5-1 thru C.5-5. Section C.5-6 of Appendix C and tables C.5-1, C.5-2, and C.5-3 provide risk impact results for the combination of all LBLOCA/LOOP changes.

4.13 Step 13: Select Combination of Changes to be Analyzed

Using the results of Step 12 for each of the individual changes analyzed using the PRA model, select a combination of two or more of these changes, to analyze the overall risk impact of the combination of changes. If only one change is selected for PRA analysis, take the PRA results from Step 12 and go to Step 15, skipping Step 14. Keep in mind that certain combinations of changes are mutually exclusive, as described in Step 4.

4.14 Step 14: Evaluate Risk Impact Resulting from Combination of Changes

Incorporate all the revisions to the PRA model described in Step 11 for the combination of selected changes. Evaluate the risk impact of the combination of changes using the five substeps described in Step 12.

4.15 Step 15: Do PRA Results Meet RG 1.174 Criteria?

According to RG 1.174, a CDF increase of $1.0\text{E-}6/\text{year}$ and a LERF increase of $1.0\text{E-}7/\text{year}$, resulting from a modification, are considered negligible. Of course, a reduction in CDF and LERF would also be acceptable.

Review the risk impact results from Step 14 to determine if these results meet the criteria of RG 1.174 (Reference 4). If the results meet the criteria, then move on to Step 16. If the results do not meet the criteria of RG 1.174, review the results of Step 12 for the individual changes and select a new combination of changes to evaluate and return to Step 14 with the new combination.

Example

For example, assume a combination of changes is selected and quantified in Step 14 and the results show an increase in CDF of $1.4\text{E}-06$ and exceeds the criteria of RG 1.174. In this case, the risk impact results for the individual changes should be reviewed to determine the specific change that should be eliminated from the selected combination in order to reduce the risk impact. Return to Step 14 with the new combination of changes and reevaluate the risk impact.

4.16 Step 16: Revise PRA Model to Support Sensitivity Cases

The PRA model created in Step 14, with the selected combination of changes incorporated, is revised in this step to quantify the sensitivity cases defined in Step 9, if any. If no sensitivity cases were defined in Step 9, skip this step and go to Step 17.

Example

Assume a sensitivity case is defined based on an F&O related to the lack of plant-specific failure rates for RHR pumps, as described in the example for Step 9. In this step, the plant-specific failure rates for RHR pumps would be incorporated into the PRA model. The PRA model would then be quantified to calculate the risk impact of the selected combination of changes to compare with the risk impact calculated in Step 14 to determine if the sensitivity case results in any changes to the conclusions derived from the quantification in Step 14.

Each sensitivity case should be quantified individually and the combination of all defined sensitivity cases should also be quantified to ensure that the issues involved in the sensitivity cases have no impact on the conclusions of this analysis.

4.17 Step 17: Perform Uncertainty Analysis per RG 1.174

Regulatory Guide 1.174 (Reference 4) provides guidelines for a CCR in which any of the individual changes causes an increase in risk. For these CCRs, a PRA quantification must be performed and the uncertainty addressed.

If a PRA quantification is performed in Step 14 for any selected LBLOCA/LOOP changes, an uncertainty analysis should be done and the uncertainty in the PRA results should be documented as part of Step 18. If no PRA quantifications are performed, because all of the selected changes result in risk decreases and are addressed qualitatively, the uncertainty in the LBLOCA/LOOP initiating event frequency should be addressed and documented in the submittal.

Example

An uncertainty analysis was performed for the generic example in Appendix C using Monte Carlo techniques. The generic example uncertainty analysis is described in Appendix C, Section C.3.8.

4.18 Step 18: Document PRA Results for Selected Combination

Document the PRA results from Steps 12, 14, and 16.

4.19 Step 19: Verify and Document Compliance with Current Regulations

Review the discussion related to compliance with current regulations in Section 3.1 for applicability to the plant being analyzed. Confirm the impact of its proposed changes on its licensing basis with respect to the GDCs, since each plant's commitment to the GDCs is different. Make any adjustments necessary to make the discussion plant-specific. Include the revised discussion in the plant-specific exemption request submittal.

4.20 Step 20: Verify and Document Compliance with Defense-in-depth Strategy

Review the discussion related to compliance with defense-in-depth in Section 3.2 for applicability to the plant being analyzed. Make any adjustments necessary to make the discussion plant-specific. Include the revised discussion in the plant-specific exemption request submittal.

4.21 Step 21: Verify and Document Safety Margins

Review the discussion related to safety margins in Section 3.3 for applicability to the plant being analyzed. Make any adjustments necessary to make the discussion plant-specific. Include the revised discussion in the plant-specific exemption request submittal.

4.22 Step 22: Verify and Document Compliance with NRC Safety Goals

Review the discussion related to NRC safety goals in Section 3.4 for applicability to the plant being analyzed. Make any adjustments necessary to make the discussion plant-specific. Include the revised discussion in the plant-specific exemption request submittal.

4.23 Step 23: Document Strategy for Monitoring Changes

Review the discussion related to monitoring changes in Section 3.5. Develop a plant-specific plan for monitoring the changes. For certain cases, existing performance monitoring required by the Maintenance Rule or MSPI is adequate. Periodically re-assess the output of the performance monitoring and make appropriate adjustments to the analysis of the risk impact of selected changes.

Include the discussion of the plant-specific plan for monitoring the changes in the exemption request submittal.

4.24 Step 24: Prepare Exemption Request

When a plant implements one or more of the changes contained in this report, it must identify any of its remaining licensing basis analyses that may be affected by those changes and submit

them in conjunction with the exemption. For example, to demonstrate continued compliance with 10 CFR 50.46, the accident analyses including all changes must bound all small break LOCA events with a concurrent LOOP and a single active failure postulated. A licensee should deterministically demonstrate that it could still mitigate the LBLOCA with offsite power available and a single active failure to confirm that compliance with the design basis is not degraded through implementing this relaxation.

Other licensing basis considerations such as ATWS, Appendix R, etc. must also be reviewed as required by 10 CFR 50.59

5.0 GENERIC EXAMPLE RISK IMPACT ASSESSMENT RESULTS

The BWROG initially submitted this topical report using the generic plant risk analysis as the basis for the exemption request, with essentially no requirement for plant-specific risk evaluation to be performed as part of the individual licensee's exemption request. In subsequent discussions with the NRC, the BWROG has agreed to revise the topical report such that the revised report becomes a guidance document for the individual licensees to prepare the exemption request. Using this revised report as the guide, individual licensees will prepare their own exemption requests, which will include any required plant-specific risk assessment. The generic risk assessment prepared as part of the original topical report has been included in Appendix C as a sample analyses to this LTR.

This section provides the results of the generic example PRA analysis described in Appendix C. This section also provides an overview of the PRA analysis and some of the details of the analysis described in more detail in Appendix C. Information in this section, and in Appendix C, can be used by the licensee to aid in developing plant-specific analyses to support the exemption request.

While the PRA model used in the example of Appendix C is characterized as "generic," it is actually an operating BWR/4 plant's model, with the unique plant-specific design attributes replaced with more common design features. Various configurations of the generic model were used in this LTR to ensure that relevant plant differences were addressed in the underlying analyses. This model has been used by the BWROG in other regulatory actions, such as Risk-Informed Technical Specification (RITS) changes. The input for the changes to "genericize" the model comes from surveys of BWR licensees to describe those attributes of their PRA models that are germane to this study (i.e., that are important to the LOCA and LOOP event sequences.) The results of these surveys were used to create the necessary permutations of the base model to capture these important attributes (Appendix C). Sensitivity studies are used to cover the most-common plant-to-plant design differences. These are factored into the implementation guide in Section 4.0.

The generic PRA model was constructed so that it can model many different BWR configurations. To evaluate the changes outlined in this report, nine explicit BWR configurations were evaluated. Other plant configurations were addressed in sensitivity analyses. The model is an integrated Level 1 and Level 2 model for internal events that can occur while the plant is operating at full power. The model explicitly covers front line systems and support systems. These systems are modeled to the super-component level (e.g., a MOV includes the valve, motor, and operator). The human error analysis includes both pre- and post-accident operator actions. Appendix C provides the details of the model.

To ensure that the conclusions drawn from the generic model are broadly applicable to the BWR fleet, the generic model results were compared to several plant-specific BWR PRA models. The focus of this comparison was the LOOP event. This is because the largest portion of the risk offset is recovered from LOOP events. As shown in Appendix C, the generic model is able to approximate the results from the plant-specific models.

In addition to benchmarking the generic model with various BWR PRA models, a set of uncertainty and sensitivity analyses were performed. The uncertainty study performed was a Monte-Carlo analysis of the basic event frequency and probability distributions. Sensitivity analyses were performed for several key attributes and assumptions in the model. The details of these analyses are presented in Appendix C. Assumptions or attributes that are important to the conclusions of this report are outlined in Section 5.1.

5.1 Example Application Details

In the initial LTR it was intended that an applicant would not be required to provide plant-specific PRA analyses if it meets the PRA assumptions and attributes enumerated in Appendix C. In the revised approach, each plant has to submit a plant-specific exemption request that will include a plant-specific assessment of the risk impact.

5.1.1 PRA Assumptions Used in Example Risk Impact Assessment

The generic PRA model was adjusted to encompass some plant-specific variability in terms of individual plant attributes and data ranges. However, the generic PRA model results are dependent upon a set of key assumptions that were made in performing the analysis of CDF and LERF effects of the LBLOCA/LOOP plant modifications. These assumptions are inherent in the event tree and fault tree construction and, if not valid for a particular plant, could alter the risk balance conclusions that resulted from the generic analysis documented in this report.

More than 70 model attributes and assumptions were assessed for their effect on the conclusions of this report. These analyses are described in Appendix C. Most of the attributes and assumptions do not have any significant effect; however some are important for the changes described in this report. To confirm that the analyses described in this report are bounding for an individual plant, it would be necessary for each plant requesting a LBLOCA/LOOP exemption to review each of these and to confirm that they apply on a plant-specific basis.

5.2 Results of Example Risk Impact Assessments

The following sections describe the risk impact assessment results from the generic example of Appendix C.

5.2.1 Optimize EDG Loading

The PRA model changes described in Section 4, Step 11 for “Optimize EDG Loading” were made in the generic BWR PRA model. Quantification of these configurations leads to a CDF decrease of $1.2\text{E-}8$ per year if the battery chargers are automatically loaded instead of the LPCS pumps and $1.4\text{E-}8$ per year if the battery chargers are loaded instead of the LPCI pumps. In both cases, the model shows a negligible change in LERF.

5.2.2 One RHR Loop in SPC Mode

The PRA model changes described in Section 4, Step 11 for “One RHR Loop in SPC Mode” were made in the generic BWR PRA model. Quantification of this configuration leads to a CDF decrease of $4.1\text{E-}8$ per year. The model shows a negligible change in LERF.

5.2.3 Eliminate LPCI Loop-Select

The PRA model changes described in Section 4, Step 11 for “Eliminate LPCI Loop-Select” were made in the generic BWR PRA model. Quantification of this change leads to a CDF increase of only $1.0\text{E-}9$ per year. The model shows a negligible change in LERF.

5.2.4 Qualitative Risk Reductions

In the example of Appendix C, the following changes from Section 2.4 were evaluated qualitatively to assess their possible impact on risk:

- Allow EDG Warm Up Prior to Loading
- Start EDGs Only When Needed
- Increased MOV Stroke Times
- Simplified EDG Testing

As indicated above, some potential benefits associated with the changes described in Section 2.4 in terms of CDF are envisioned, but not directly quantified. Three aspects were examined:

- Diesel Generator Availability
- Diesel Generator Reliability
- Operator Action Reliability

There is little data to quantitatively prove that slower starts will increase EDG reliability. EDG experts believe that further elimination of fast starts can improve reliability, but cannot easily provide a number. NRC requested in NRC Generic Letter 84-15 and NRC Information Notice

85-32 that plants consider steps to reduce fast starts. The industry has eliminated fast starts from testing programs, and a portion of the overall improvement in EDG reliability has resulted from these steps, but unplanned starts are still fast starts.

Results of Example Application

A reasonable reduction in unavailability and failure rates as a result of the changes described in this report would be 10%. For example, the average unavailability of EDGs is $1.01\text{E-}2$.

Assuming an average annual required availability time of 8760 hours, the total unavailability per EDG is about 88 hours. Nearly a 10% reduction in unavailability would be realized if one shift (8 hours) of down time per year was avoided. Proposed Revision to NEI 99-02 (Reference 5) reports the probability of an EDG failure to start on demand is $1.1\text{E-}2$. This translates into about one failure per plant every 3 years, assuming the generators are started monthly and the average BWR has 2.5 diesels. Extending this to one failure per 3.3 years results in a 10% reduction of the failure probability.

It is similarly difficult to predict the reduction of the operator action failure rates. Once again, though, a moderate decrease of 10% is expected if the proposed changes are made. This only applies to actions in the model that share dependence with the actions to secure a diesel generator that has spuriously started. These are defined as those actions taken outside the control room, that need to happen within one hour of the initiating event. The operator actions in the generic PRA-model, identified as possibly impacted by this change, are listed in Appendix C, Section C.5.5.

Rather than specifying an impact on the parameter changes and re-quantifying the model, the risk impact was evaluated examining a reasonable range of improvements of the affected parameters. Depending on the plant configuration, improvements as small as 10% in EDG related terms could offset approximately 47% of the assumed CDF increase associated with eliminating the licensing requirement for LBLOCA/LOOP. These EDG improvements could completely offset the change in LERF. Plants that rely more on their EDGs (i.e. those plants with a less reliable local grid) would benefit more from these changes. The results for all analyzed plant configurations are presented in Appendix C.

In addition, improving operator performance by 10% can offset approximately 31% of the assumed increase in CDF associated with eliminating the licensing requirement for LBLOCA/LOOP.

6.0 CONCLUSIONS

The BWROG initially submitted this topical report in April 2004 using the generic plant risk analysis as the basis for the exemption request, with essentially no requirement for plant-specific risk evaluation or deterministic thermal-hydraulic analysis to be performed as part of the individual licensee's exemption request. In subsequent discussions with the NRC, the BWROG agreed to revise the topical report such that the revised report becomes a guidance document for the individual licensees to prepare the exemption request. Section 4.0 provides the guide for individual licensees.

The BWROG seeks an exemption from the current requirements that requires consideration of simultaneous occurrence of LOOP with large break LOCAs. Such an exemption would provide the licensees an opportunity to implement certain plant modifications which would improve plant safety for the more likely transients and accidents, while negatively impacting the extremely unlikely event of coincident large break LOCA and LOOP.

To evaluate the effect of eliminating the LBLOCA/LOOP requirement, a generic probabilistic risk analysis (PRA) was performed and documented in Appendix C. The results of the generic example risk analysis showed that the probability of a large break LOCA in combination with a LOOP is consistent with the Regulatory Guide 1.174 (Reference 4) threshold for such regulatory changes (i.e., less than $1.0E-6$) and that there was an overall risk balance between the risk increase associated with eliminating the LBLOCA/LOOP requirement and the risk reduction associated with the beneficial design changes. However, each licensee will be required to submit a plant-specific risk assessment as part of his exemption request.

For the deterministic evaluation, the LBLOCA/LOOP event was recategorized as a "beyond design basis accident" and analyzed using the best-estimate code in Appendix B. The appendix first benchmarked the MAAP4 code against TRACG02, an NRC-recognized code. Then the LBLOCA/LOOP event was analyzed using the MAAP4 code for the generic plant after implementation of various combinations of the modifications under consideration. The results show that the PCT temperatures are within the acceptable limit for each generic plant, for each set of plant modifications. Two of the MAAP results with relative high PCT values, one for a BWR3/4 plant and one for a BWRE5/6 plant, were analyzed again using the TRACG02 code. The TRACG02 best-estimate thermal-hydraulic analyses also showed that even if a LBLOCA event combined with a LOOP were to occur, with the associated ECCS injection delays and flow reductions, the core would be maintained in a coolable geometry and that 10 CFR 50.46 acceptance criteria would be met.

The revised LTR permits individual licensees to use the MAAP4 results in Appendix B if the key plant parameters for the licensee's plant are bounded by those used in Appendix B and documented in this report. If the plant parameters are not bounded, then the licensees will have

to perform plant-specific thermal-hydraulic analyses. The generic thermal-hydraulic analyses in Appendix B did not cover the BWR2 plants, and those plants will have to perform plant-specific analyses as part of their exemption requests.

It is also concluded that the elimination of the LBLOCA/LOOP requirement and the implementation of the identified design changes will be in compliance with existing regulations, maintain adequate defense-in-depth and preserve safety margins. Using the analyses provided here for the generic plant, each licensee will have to document this for his plant as part of his exemption request.

It is concluded that the changes in CDF and LERF from eliminating LBLOCA/LOOP requirements, and implementing the identified plant modifications, are acceptable and within the bounds defined by the LBLOCA/LOOP framework and Regulatory Guide 1.174.

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APPENDIX-A
ECCS SYSTEM SCHEMATICS

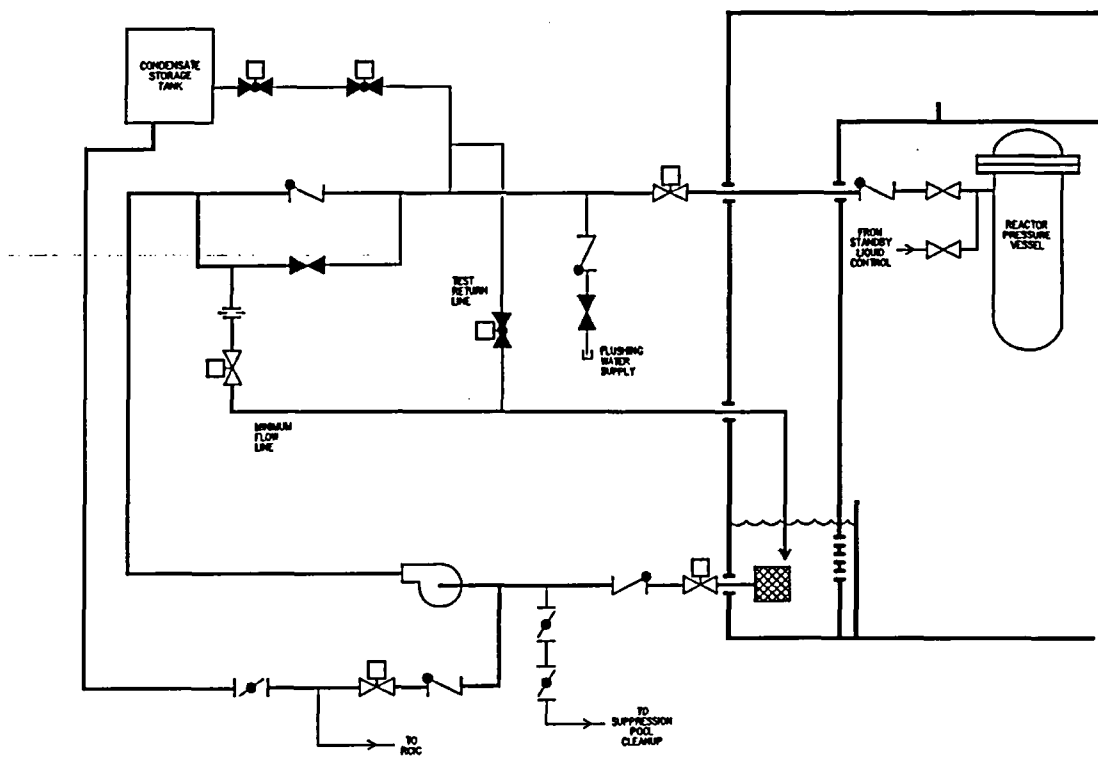


Figure A-1
High Pressure Core Spray Simplified Schematic

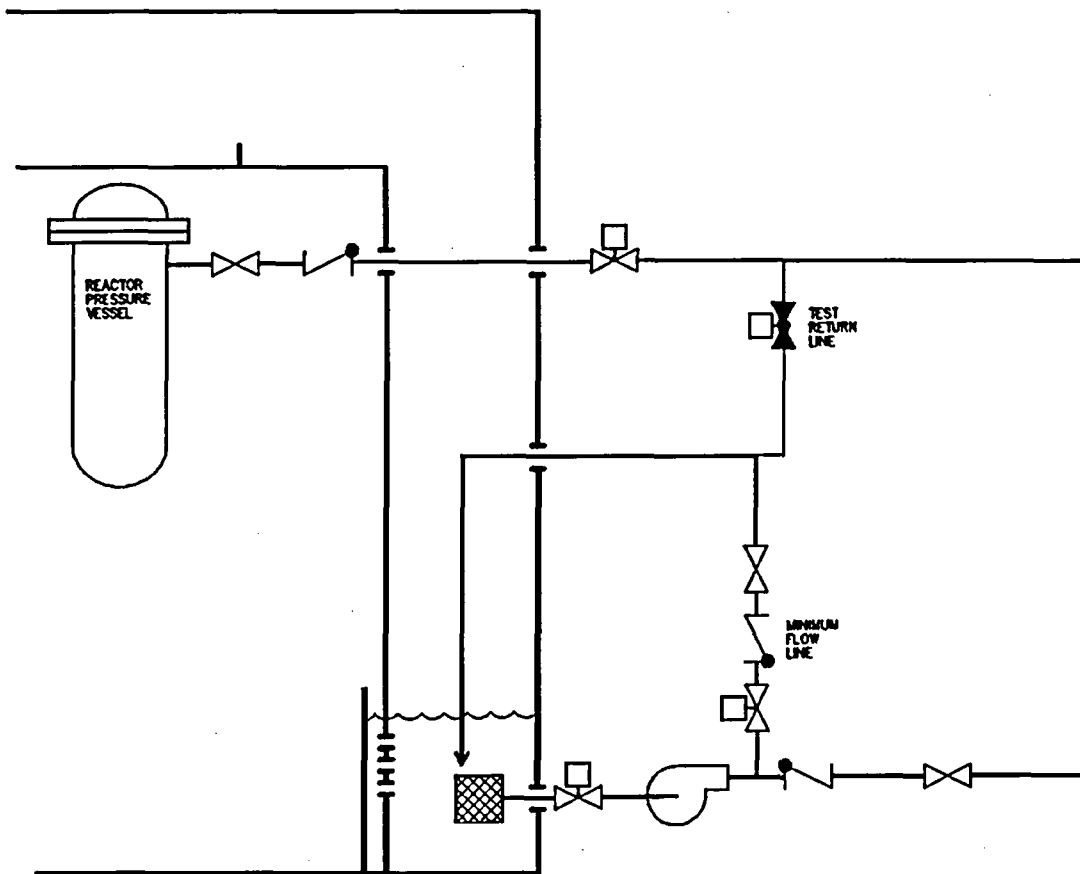


Figure A-2
Low Pressure Coolant Injection Schematic (One loop shown)

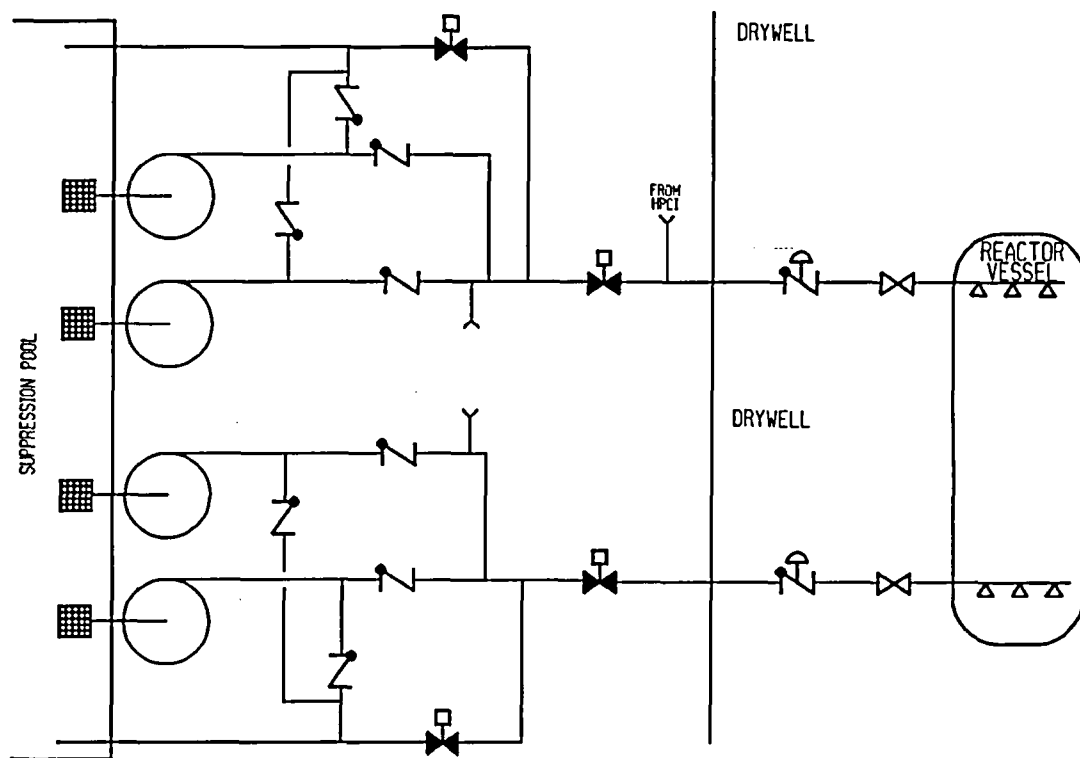


Figure A-3
Core Spray System Simplified Schematic

APPENDIX B

THERMAL-HYDRAULIC ASSESSMENT OF LBLOCA/LOOP

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B.1 PURPOSE

The purpose of the thermal-hydraulic analysis detailed in this appendix and summarized in Section 2.5 is threefold:

1. In order to demonstrate defense-in-depth for the LBLOCA/LOOP separation exemption, per RG 1.174, this Appendix will demonstrate that the LBLOCA/LOOP event can continue to be mitigated, even after implementing the plant modifications discussed in Section 2.4 (LBLOCA/LOOP plant changes). As outlined in Sections 2 and 3 of this report, the defense-in-depth philosophy has traditionally been applied in reactor design and operation to provide multiple means to accomplish safety functions and prevent the release of radioactive material.
2. To demonstrate that MAAP4 is an acceptable tool for performing the thermal-hydraulic analyses required for the LBLOCA/LOOP exemption for the specific cases analyzed here. This is done by benchmarking the MAAP4 computer code against the NRC-recognized computer code TRACG02 for some bounding cases.
3. To provide MAAP4 results for several BWR plant configurations that can be used and referenced by licensees in their exemption submittals, as long as their plant parameters fall within the bounds of the input parameters used in the generic analyses of this appendix.

B.2 INTRODUCTION

Plant changes associated with implementation of LBLOCA/LOOP will result in a delay in the start of ECCS injection. They will also result in converting some equipment from automatic to manual operation and vice versa. Therefore, the impact of these plant changes was evaluated to determine the viability of implementing the changes. Given the low probability of a LBLOCA occurring concurrent with the loss of offsite power (LOOP), this event will now be considered to be a "mitigated beyond design basis accident." Consistent with this re-categorization, this evaluation was performed using best-estimate assumptions and methods. Consistent with the use of best-estimate methods and assumptions, the acceptance criterion for the analyses was established to maintain the core in the reactor vessel in a coolable geometry.

Some measure of mitigation capability should be retained for the new beyond design basis accident, LBLOCA/LOOP, assuming the other plant changes were implemented. For the "mitigated beyond design basis accident", some level of core damage can be tolerated. In addition, by definition, a LOCA is a breach of the fission product barrier of the reactor coolant pressure boundary. Thus, to ensure that the next fission product barrier of the containment was not challenged by this new event, it was decided that retaining the core material inside the reactor vessel would be used as the acceptance criterion for mitigation, i.e., maintaining the fuel in a "coolable geometry" was chosen to ensure that the core material was retained in the vessel. As an extra measure of conservatism (i.e., to demonstrate "safety margins" as specified in RG 1.174), the existing 10 CFR 50.46 acceptance criteria of 2200 °F peak cladding temperature (PCT) and 17% local cladding oxidation fraction were chosen as the figures of merit for demonstrating that a "coolable geometry" is maintained. In addition, the thermal-hydraulic analysis addressed localized effects by looking at a group of 4 limiting fuel bundles (less than 1% of the core) representing the highest LHGR. A typical best-estimate analysis uses a coarser representation of the core (10% - 20%) as a measure for core damage.

The MAAP4 code is capable of performing the required thermal-hydraulic analysis. However, because the MAAP4 code has not been subjected to regulatory review and approval as a tool for design basis analysis, it was benchmarked against the TRACG02 code, an NRC-recognized code. The benchmark analyses documented in Section B.4 showed that the TRACG02 and MAAP4 PCT values compared reasonably well and it was concluded that MAAP4 is an acceptable tool to analyze the LBLOCA/LOOP event. Then a series of analyses were performed with MAAP4 with the proposed plant modifications implemented in the plant. The results, which are documented in, Section B.5, showed that all acceptance criteria are met. For added measure of confidence, the two most limiting MAAP4 cases were reanalyzed using the TRACG02 computer code. The results of that analysis are documented in Section B.4. The TRACG02 results also showed that the PCT results met the acceptance criteria.

Additional MAAP4 cases were analyzed to assess the impact of plant-to-plant variability on the results of the analysis. It was demonstrated that changes in RPV liquid volume of $\pm 20\%$ and a variation in ECCS injection flow of 10% did not generate significant changes in PCT that would alter the conclusions of this evaluation.

The results of this appendix are applicable to all BWR 3,4,5 and 6 product lines, as discussed further in the appendix. BWR2 plants were not specifically analyzed, and plant-specific MAAP analysis would be required as part of their exemption request submittals.

This Appendix provides the details of this evaluation, which is summarized in Section 2.5 of this report.

B.3 THERMAL-HYDRAULIC ANALYSIS OVERVIEW

B.3.1 Important LOCA Analysis Considerations

This section identifies the considerations that are important to simulate properly in order to predict the fuel response during a LBLOCA. Each of the items listed below involve one or more phenomena that are important in the prediction of the PCT and cladding oxidation.

The aspects of a LOCA analysis that are important in predicting the timing and magnitude of the peak cladding temperature are:

1. Sources of heat
2. Blowdown heat transfer
3. Post-blowdown heat-up rate
4. Core reflood time
5. Core reflood heat transfer

Any two codes used to perform a LBLOCA analysis that agree with respect to these considerations will predict similar PCT values.

B.3.2 Overview of Computer Codes

The LBLOCA analyses discussed in this Appendix were performed with the TRACG02A (referred to as TRACG02) and MAAP 4.0.4 (referred to as MAAP4) computer codes.

A brief overview of each of these codes is provided below.

B.3.2.1 TRACG02 Overview

TRACG is a computer code for the prediction of boiling water reactor transients ranging from abnormal operational occurrences (AOOs) to design basis loss-of-coolant accidents, stability and anticipated transients without scram (ATWS). TRACG incorporates a two-fluid thermal-hydraulic model for the reactor vessel and the primary coolant system, a three-dimensional kinetics model for the reactor core and one-dimensional calculations in the other components.

The conservation equations for mass, momentum and energy are closed through an extensive set of basic models consisting of constitutive correlations for shear and heat transfer at the gas/liquid interface as well as at the wall. The constitutive correlations are flow regime dependent, and are determined based on a single-flow regime map, which is used consistently throughout the code. In addition to the basic thermal-hydraulic models, TRACG contains a set of component models for BWR components, such as recirculation pumps, jet pumps, fuel channels, steam separators and dryers. TRACG also contains a control system model capable of simulating the major BWR control systems such as the pressure, level and recirculation flow control systems.

TRACG02 is a “best-estimate” system computer code applicable for analysis of loss-of-coolant accidents (LOCAs) including large and small breaks at any location.

While the application range of TRACG02 includes LOCA analysis, a detailed application methodology for LOCA has not been defined for TRACG02, as it has for evaluating Abnormal Operating Occurrences (AOOs), including Anticipated Transients Without Scram (ATWS). GE is part way through the development of a LOCA application methodology, and an estimated TRACG02 modeling uncertainty adder, based upon benchmarking with other LOCA evaluation models and testing data, is applied to the TRACG02 results.

B.3.2.2 MAAP4 Overview

MAAP4 is an EPRI tool that is used primarily for the modeling of PRA event sequences in order to evaluate the sequence timing, to determine system success criteria and to identify if a sequence results in a core damage state. There is a BWR and a PWR version. MAAP4 includes models for the important accident phenomena that might occur within the primary system, containment and reactor/auxiliary building. MAAP4 calculates the progression of the postulated accident sequence, including the disposition of the fission products, from a set of initiating events to either a safe, stable state or to an impaired containment condition and the possible release of fission products to the environment. MAAP4 has modeling capabilities for the determination of the PCT during a LBLOCA.

The MAAP4 methodology includes the following models, which are most pertinent to the analysis of a Large Break LOCA event:

- (a) General Core Model
- (b) Break Flow Model
- (c) Two Phase Mixture Level
- (d) Overheat and Clad Oxidation of Uncovered Core Nodes
 - 1. Core Heat Up
 - 2. Metal-Water Reaction
- (e) Quenching for Reflooded Core Nodes

MAAP4 has the advantage of being easier and faster to execute than some other codes, which allows for the analysis of a variety of cases in a relatively short period of time. MAAP4 is used in this report to perform an analysis of the LBLOCA/LOOP changes for the various BWR plant designs to be used by licensees in their exemption submittals. It is also used to perform a sensitivity analysis to evaluate the expected PCT impact of the identified key plant-specific variables of Reactor Coolant System (RCS) volume and ECCS flow rate to provide a justification for applicability of the results among the various plants in the BWR fleet.

B.3.3 Technical Approach

As outlined in Section 2.5 of the report, the approach used to evaluate the impact of the proposed LBLOCA/LOOP changes was as follows:

- Benchmark LBLOCA/LOOP cases were performed with both the MAAP4 and TRACG02. The key phenomena important to a LBLOCA analysis were compared between the two codes. Preliminary analyses prior to the benchmark analyses identified certain changes that are required to be made to the MAAP4 model after which the MAAP4 analyses provide results similar to TRACG02 results. The benchmark analyses are discussed in Section B.4.
- A series of MAAP4 analysis cases was performed using the various equipment combinations remaining after implementing all of the LBLOCA/LOOP changes. MAAP4 analyses were performed for plants representing BWR 3 through BWR 6 and these are discussed in Section B.5.
- A series of MAAP4 sensitivity cases to evaluate the effect of plant-to-plant variability were performed. The sensitivity analysis is discussed in Section B.6. These cases are expected to bound the plant variability within the BWR 3/4/5/6 fleet.
- For additional conservatism, the MAAP4 analysis case with the highest PCT for the BWR4 and one for the BWR6 were then run using TRACG02 for comparison with MAAP4 results to validate MAAP4 as a tool for analyzing the changes involved in the implementation of LBLOCA/LOOP. The BWR6 case selected did not have the highest PCT. It was chosen because it offered the opportunity to evaluate the impact of the LBLOCA/LOOP changes in scenarios requiring both high pressure and low pressure injection sources. The difference in peak PCT between the BWR6 case selected and the BWR6 case with the highest PCT is less than 100 °F and there is significant margin to the 2200 °F acceptance criteria. The MAAP4 and TRACG02 analyses are provided in Section B.4.

B.4 MAAP4/TRACG02 BENCHMARK

B.4.1 Introduction

The purpose of this section is to document the benchmark analyses performed to demonstrate that MAAP4 is an acceptable tool for performing the thermal-hydraulic analyses required for the LBLOCA/LOOP exemption for the specific cases analyzed here.

In Section B.5, a series of MAAP4 runs were made for the LBLOCA/LOOP event for various BWR plants with the proposed plant modifications implemented. The limiting case for the BWR4 and the limiting case for the BWR6 were selected for the benchmark comparison between MAAP4 and TRACG02. The limiting PCT case for the BWR4 was Case A at an uprate power of 25% and the PCT case that was run for the BWR6 was Case C at an uprate power of 25%.

The PCT for BWR6 Case D (2 LPCI) was actually the highest PCT case for the BWR6. It was decided to utilize Case C (1LPCI, 1HPCS) for the TRACG02 benchmark analysis in order to be able to include the phenomenology associated with the injection of HPCS. Since the PCT between the cases was not substantially different, it was judged to be more important to account for the phenomenology in TRACG02. This also provides a more meaningful reference comparison between TRACG02 and MAAP4 as described in the following section of this report.

Key parameters from the TRACG02 analyses and the MAAP4 analyses are compared in this section. Transient plots comparing these data are included as Figures B.4-1 to B.4-5 for the BWR4 and Figures B.4-6 to B.4-10 for the BWR6.

B.4.1.1 LBLOCA/LOOP Event Description

The event that is modeled in TRACG02, for both the BWR4 and the BWR6, is a double-ended guillotine rupture of a recirculation suction line coincident with a loss of offsite power (LOOP).

In the analysis, the EDG is assumed to start on a Level 1-signal (L1) and an EDG delay following L1 is assumed in accordance with the LBLOCA/LOOP changes discussed earlier. It should be noted that the L1 anticipatory start signal is not critical to the analysis since EDG start would also occur on bus undervoltage. The delay time is the important consideration, not the anticipatory start signal.

The system assumptions for the BWR4 and BWR6 analysis cases are different, reflecting the design differences between the plants. The specific cases analyzed and the results are discussed in the following sections.

Key parameter values used for the BWR4 and the BWR6 analyses are provided in Table B.4-1.

Table B.4- 1
Key Parameter Values Used in the BWR4 and BWR6 Analyses

Parameter	Description	BWR4 Analysis Value	BWR6 Analysis Value
RPV Dome Pressure, (Pa)		7348122.0	7232505.0
Reactor Core Power, (W)		3042400000.0	4510400000.0
Steam Flow, (kg/sec)		1674.0	2494.35
Feed water Flow (kg/sec)		1679.1	2492.02
Feed water enthalpy (J/kg)		0.9632E+06	0.9632E+06
Jet Pump #1 Discharge Flow Rate, (kg/sec)		4846.6	6446.3
Jet Pump #2 Discharge Flow Rate, (kg/sec)		4852.8	6494.3
Radial peaking	TRAC CPR limited channel	1.5085	1.3903
	TRAC PLHGR limited channel	1.4925	1.3617
ECCS Systems Available		Two LPCI in the same loop (intact loop)	1 LPCI 1 HPCS
ECCS Systems start signal	LPCI	L1	L1 (Both)
ECCS Systems delay time from L1 signal (seconds)	Delay time consists of an EDG start delay and a LPCI loop fill time delay	127	147 (HPCS) 157 (LPCI)

Table B.4-1
Key Parameter Values Used in the BWR4 and BWR6 Analyses (*Continue*)

Parameter	Description	BWR4 Analysis Value		BWR6 Analysis Value	
		Head (psia)	Flow (ft ³ /hr)		
ECCS Pump Curve	Two LPCI into one loop performance. The curve shown reflects the LPCI flow for one system only	210.7	0	NA	
		191.1	18992		
		171.5	26860		
		132.3	37984		
		93.1	46517		
		53.9	53710		
		34.3	56975		
		0.0	60060		
	One HPCS Pump	NA		Head (psia)	Flow (ft ³ /hr)
				1.001E+07	0.0
				1215.0	0.0
				1215.0	2646.0
				1162.0	9670.0
				214.7	40030.0
				14.7	48110.0
				14.7	48110.0
				14.7	48110.0
	One LPCI Pump into shroud	NA		Head (psia)	Flow (ft ³ /hr)
				870.2	0.0
				239.3	0.0
				211.8	13610.0
				194.4	18940.0
				172.6	24400.0
				149.4	28990.0
				127.2	33020.0
				104.7	36680.0
				82.2	40010.0
				59.8	43110.0
				34.7	46310.0
				14.7	49920.0

B.4.2 BWR4 Case A Comparison

B.4.2.1 Overview (Case A)

This section provides a discussion of how MAAP4 compares with TRACG02 for the evaluation of a BWR4 LBLOCA with 2 LPCI pumps injecting into the intact recirculation loop and a 90-second EDG delay time (Case A from the MAAP4 scoping analyses summarized in Table B.5-2). The comparison is provided for reactor power, reactor vessel pressure, break flow rate, ECCS flow rate and peak cladding temperature. Table B.4-2 below provides a comparison of the timing of key events in both the MAAP4 and TRACG02 analyses.

As can be seen, the Level 1 setpoint is reached slightly sooner in MAAP4. This is due to a somewhat faster drop in level in MAAP4. This would result in an earlier LPCI injection time by about 3 seconds. Another difference is that TRACG02 accounts for the refill of the recirculation loop before directing any LPCI flow into the vessel, which takes less than 20 seconds with two LPCI pumps injecting into the intact loop. In order to account for this in MAAP4, the LPCI injection valve delay time of 37 seconds was increased to 57 seconds. The pressure response between the codes is very similar. Further discussion of the reactor vessel pressure comparison is provided later in this section.

In order to obtain the same adiabatic heatup rate in both TRACG02 and MAAP4, the heat generation in the "hottest node" must match. In the TRACG02 cases limiting bundles are modeled with different limiting fuel parameters. The Critical Power Ratio (CPR) or Linear Heat Generation Rate (LHGR) limits are assumed for the fuel bundles. Top, bottom, or center-peaked power shapes are assumed for the limiting bundles. The remainder of the core has a nominal, center-peaked power shape. In the MAAP4 model a center fuel ring was added that matches the power shape in the TRACG02 bundle with the highest LHGR for any node and is top-peaked. This fuel ring contains the equivalent of four bundles.

The MAAP4 axial power distribution for the various core rings is depicted in Figure B.4-11 below. The hot channel is top-peaked with the highest core peaking factors.

TRACG02 uses a two-phase discharge model with multiple break locations to simulate a recirculation suction line large break LOCA. The environment is used as the break downstream volume to minimize the backpressure. Use of these break elements shows a close match to experimental data. A similar break nodalization scheme is implemented for the MAAP4 analysis using the default LOCA and adding generalized openings to model the jet pump break locations. A reasonably close match to the TRACG02 data was achieved.

An additional sensitivity analysis was performed that varied the break discharge coefficient as a function of time over the first 20 seconds in an attempt to better match the liquid and vapor mass and energy release rates. Approximately the same total break flow was achieved for the first 20

seconds of the analysis. However, since there was no significant change in the PCT, the MAAP4 default break discharge coefficient of 0.7 was used for the final benchmark analysis.

There are several points of note from the MAAP4 vs. TRACG02 comparison. First, MAAP4 does not predict the same temperature drop during the blowdown as TRACG02. This response is due to the MAAP4 heat transfer mode change to film boiling when the core flow decreases to 10% of the full power flow, which occurs from 10 to 20 seconds. To compensate for this behavior the film boiling heat transfer coefficient was increased during this period, which improved the results. However, the core heatup in MAAP4 still starts from a higher temperature than in TRACG02. This difference is more pronounced for the BWR6 than the BWR4.

Another difference was noted in the time to begin vessel reflood. In MAAP4, LPCI flow is immediately directed into the lower plenum upon system actuation. The nodalization in TRACG02 forces the recirculation loop to be refilled prior to directing any LPCI flow into the jet pumps. This phenomenon causes a delay in core reflood for scenarios that involve LPCI. This phenomenon only affects plants in which LPCI is injected into the recirculation loops.

Table B.4-2
Timing of Key Events in the BWR4
MAAP -TRACG Comparison

EVENT	MAAP (sec)	TRACG (sec)
Feedwater Pump Trip	0.0	0.00
Reactor Scram	0.5	0.0
Level 1	4.6	7.76
MSIV initiation (4 sec stroke)	5.2	0.5
ECCS Actuation	151.6	134.8

B.4.2.2 Reactor Power (Case A)

The reactor power comparison is provided in Figure B.4-1. As can be seen in the figure, the power response between the two codes is very similar. While the scram time is slightly sooner in TRACG02, the overall impact on the reactor power is not significant.

B.4.2.3 Reactor Vessel Pressure (Case A)

The reactor pressure comparison is provided in Figure B.4-2. The pressure comparison between the two codes is quite good. MAAP4 exhibits a small pressure increase at the beginning of core reflood, which is not exhibited by TRACG02. This small pressure spike causes a reduction in the LPCI injection flow over a period of about 50 seconds, but overall the pressure effect does not have

a significant impact on the results of the analysis. The cause of the pressure spike is associated with a rapid energy transfer that occurs when the core begins to reflood.

B.4.2.4 Break Flow Rate (Case A)

Since the reactor pressures matched closely, it would be expected that the break flow rate would also be a close comparison. The break flow rate comparison is shown in Figure B.4-3 and shows a very close similarity. In order to assure that this parameter matched fairly closely, the MAAP4 liquid region and steam region break areas were increased slightly to provide a closer approximation to the TRACG02 break flow rate.

B.4.2.5 ECCS Flow (Case A)

Figure B.4-4 shows the LPCI flow into the intact loop. The flow rates are prescriptive functions of vessel pressure and are the same between the codes. In MAAP4, ECCS flow begins 20 seconds later than in TRACG02. This delay was added to the MAAP4 input to simulate the refill of the intact recirculation loop. This phenomenon is explicitly calculated in TRACG02 and not in MAAP4. The reduction in flow in the MAAP4 case at about 200 seconds is due to the pressure increase during reflood that was described in Section B.4.2.3.

B.4.2.6 Peak Cladding Temperature (Case A)

Overall, with the changes made to the MAAP analysis discussed above, MAAP predicts higher peak cladding temperatures than TRACG02 until the core quenching phase of the event. These results are presented in Figure B.4-5.

There are three phases in the scenario to consider. First is the PCT response during the blowdown (0 to 20 seconds). Both codes show an initial drop in clad temperature. When the recirculation suction line becomes uncovered, however, the clad temperature in MAAP4 would normally increase by several hundred degrees because there is logic in MAAP4 to change the heat transfer mode to film boiling when the core flow is reduced below 10% of the full power flow. In order to match the TRACG02 model, which is viewed as best-estimate, the film boiling heat transfer coefficient in MAAP4 was increased to 1170 btu/hr-ft²-°F, which corresponds to the heat transfer prior to the mode change to film boiling. It is maintained until the core reflood begins, at which time the film boiling heat transfer coefficient is returned to its normal value. The result is a relatively close match for the PCT at about 20 seconds, about 500°F, when the fuel heatup begins.

In the next phase, most of the core is uncovered and there is little steam flow through the core. In this phase TRACG02 and MAAP4 PCT predictions compare rather well. The rate of heatup is similar between the codes, with MAAP4 showing about a 10% higher heatup rate.

The final phase models the quench of the core during reflood. In MAAP4, this occurs rapidly. Note that if the PCT is above 1800°F, there is a brief increase in temperature when there is steam available for metal-water reaction (See Fig B.4-5).

From previous studies, there are known model uncertainties in the TRACG02 code that impact the prediction of the PCT during a LBLOCA event. To account for these uncertainties, a PCT adder* of 193°F was added to the TRACG02 BWR4 analysis PCT results. This results in a TRACG02 PCT of about 1951°F versus a MAAP4 PCT of about 2000°F. This shows that the PCT predicted by MAAP is very close, but somewhat more conservative, than the adjusted TRACG02 PCT.

* While the application range of TRACG02 includes LOCA analysis, a detailed application methodology for LOCA has not been defined for TRACG02, as it has for evaluating Abnormal Operating Occurrences (AOOs), including Anticipated Transients Without Scram (ATWS). GE is part way through the development of a LOCA application methodology, and an estimated TRACG02 modeling uncertainty adder, based upon benchmarking with other LOCA evaluation models and testing data, is applied to the TRACG02 results.

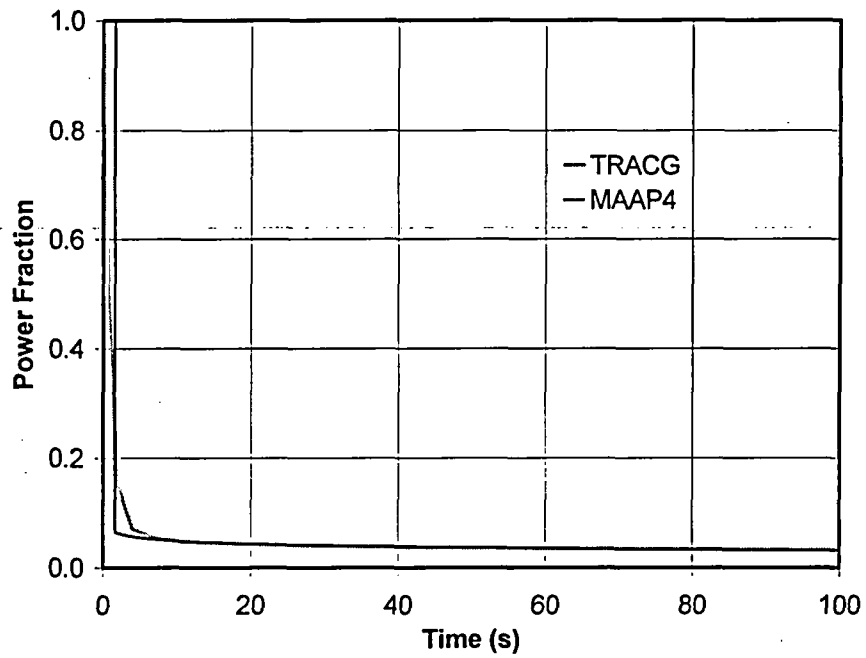


Figure B.4-1
BWR4 Case A: Reactor Power Comparison

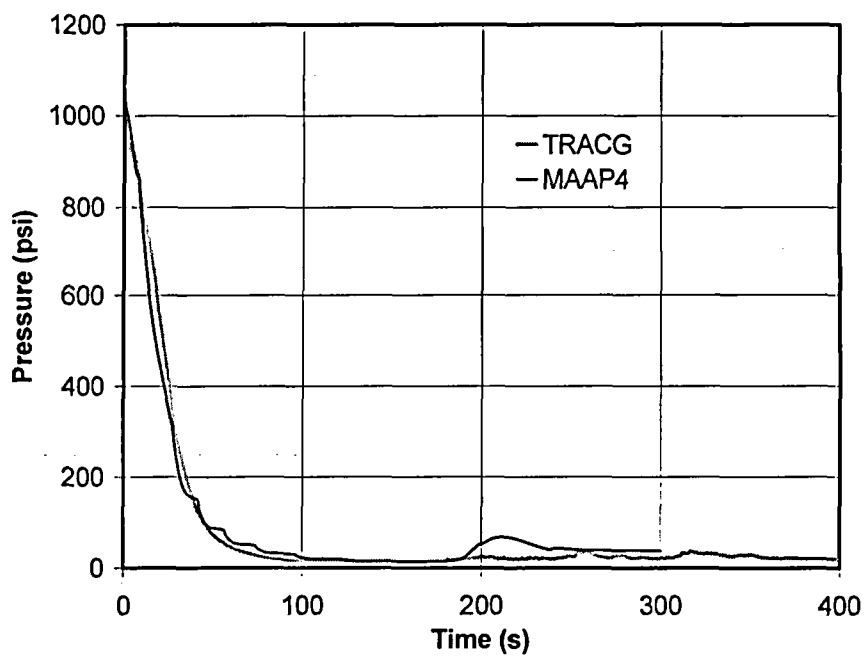


Figure B.4-2
BWR4 Case A: Reactor Vessel Pressure Comparison

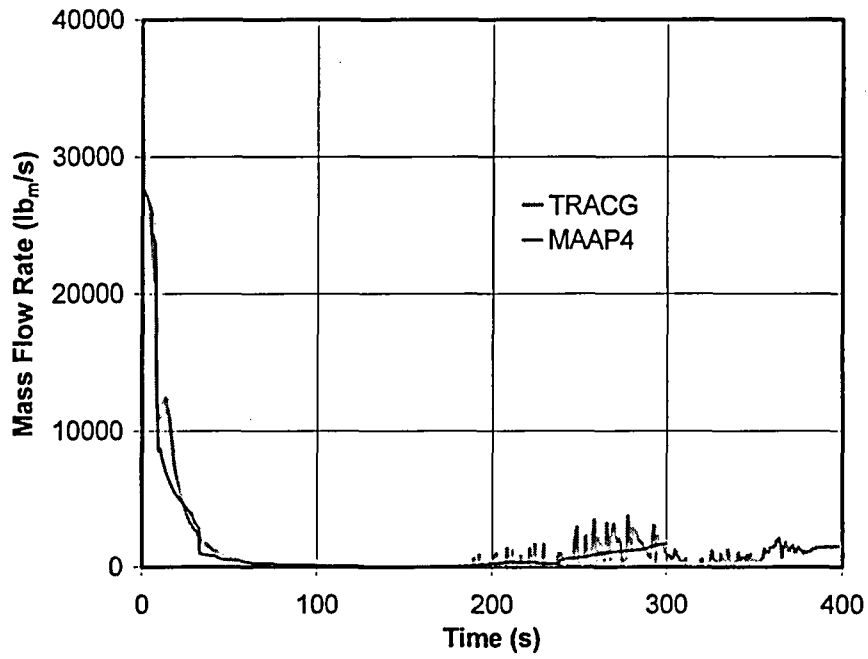


Figure B.4-3
BWR4 Case A: Break Flow Rate Comparison

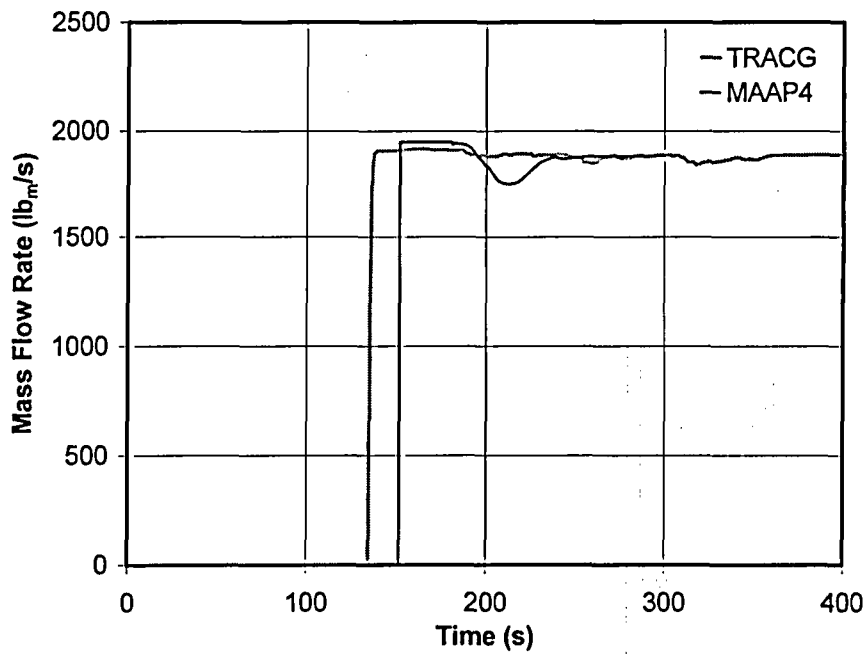


Figure B.4-4
BWR4 Case A: ECCS Flow Comparison

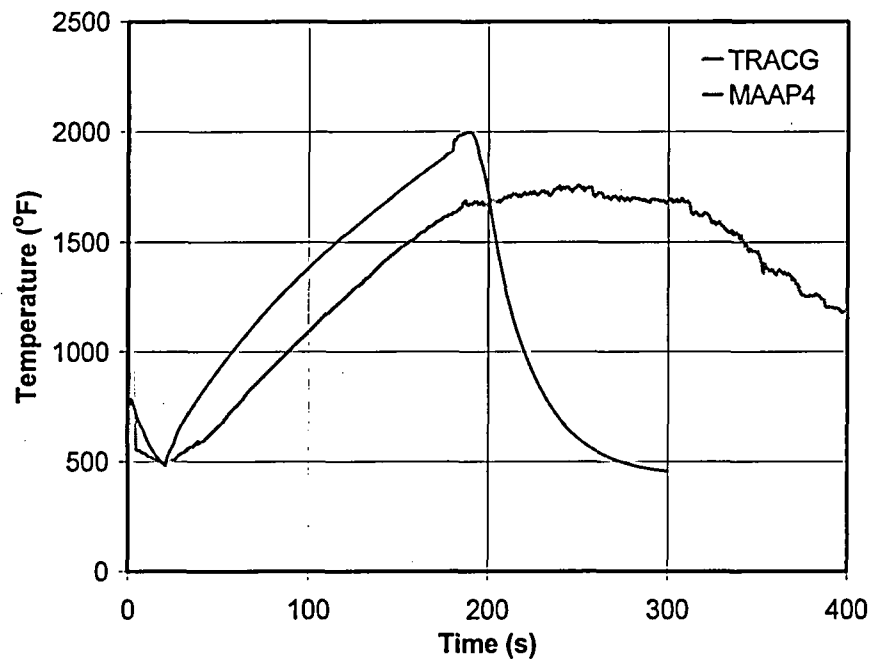


Figure B.4-5
BWR4 Case A: Peak Cladding Temperature Comparison

B.4.3 BWR6 Case C Comparison

B.4.3.1 Overview (Case C)

This section provides a discussion of how MAAP4 compares with TRACG02 for the evaluation of a BWR6 LBLOCA with 1 LPCI pump and 1 HPCS pump injecting into the core. A 120-second EDG delay time is assumed. This event is Case C from the MAAP scoping analyses summarized in Table B.5-2. The comparison is provided for reactor power, reactor vessel pressure, break flow rate, ECCS flow rate and peak cladding temperature. Table B.4-3 below provides a comparison of the timing of key events in both the MAAP and TRACG02 the analyses.

The same adjustments to the core model and break area were made for the BWR6 cases as were made for the BWR4.

The time of ECCS injection is very critical to the analysis results. MAAP depressurizes somewhat faster than TRACG02 so the LPCI pressure permissive is reached about 5.4 seconds sooner but this is not important because the time of LPCI injection is very close. The HPCS injection time for both codes is also within about 1 second. The main reason for this difference is the time to reach Level 1, which was used as the HPCS initiator for both analyses.

Table B.4-3
Timing of Key Events in the BWR6
MAAP-TRACG Comparison

EVENT	MAAP (sec)	TRACG (sec)
Feedwater Pump Trip	0.0	0.0
Reactor Scram*	4.0	1.157
Low Level HPCS Setpoint**	7.1	7.72
Low Level LPCI Setpoint (L1)	7.1	7.72
MSIV Initiation (5 sec stroke)	7.1	7.72
LPCI Pressure Permissive	37.0	39.23
HPCS Injection Begins	154.1	154.8
LPCI Injection Begins	164.2	164.3

* TRACG02 scram on High Drywell Pressure

** TRACG02 and MAAP4 initiated HPCS on L1

B.4.3.2 Reactor Power (Case C)

The reactor power comparison is provided in Figure B.4-6. As can be seen in the figure, the power response between the two codes is very similar. While the scram time is slightly sooner in TRACG02, the overall impact on the reactor power is not significant.

B.4.3.3 Reactor Vessel Pressure (Case C)

The reactor pressure comparison is provided in Figure B.4-7. MAAP4 results in a more rapid pressure reduction during blowdown than TRACG02 for the BWR6. This difference is not critical to the analysis results. There is an increase in the MAAP4 vessel pressure at about 150 seconds, which is coincident with the time at which HPCS injects into the core. The MAAP4 code provides a much more rapid core heat transfer response to the HPCS injection than TRACG02. The result is additional steam generation that is the cause of the pressure increase. The higher core heat transfer also results in a more rapid reduction of the fuel cladding temperature, which is discussed below.

B.4.3.4 Break Flow Rate (Case C)

The break flow rate comparison for the BWR6 analyses is shown in Figure B.4-8 and shows a very close similarity between the codes. In order to assure that this parameter matched fairly closely, the MAAP4 liquid-region-and-steam-region-break-areas-were-increased-slightly to provide a closer approximation to the TRACG02 break flow rate similar to what was done for the BWR4 MAAP4 analysis.

B.4.3.5 ECCS Flow (Case C)

Figure B.4-9 shows the HPCS injection at about 154 seconds followed by the LPCI injection at about 164 seconds. Because the LPCI and HPCS flows are a function of vessel pressure, the ECCS flow rates in MAAP4 are initially less than the TRACG02 flow rate because the MAAP4 vessel pressure at the time of ECCS injection is greater than the TRACG02 vessel pressure. As the pressures between the codes equalize, the MAAP4 ECCS flow rates increase to more closely match the TRACG02 ECCS flow rates.

B.4.3.6 Peak Cladding Temperature (Case C)

Overall, with the changes made to the MAAP4 analysis discussed above, MAAP predicts higher peak cladding temperatures than TRACG02 until the core-quenching phase of the event. These results are presented in Figure B.4-10.

There are three phases in the scenario to consider. First is the PCT response during the blowdown (0 to 20 seconds). Both codes show an initial drop in clad temperature. When the recirculation suction line becomes uncovered, however, the clad temperature in MAAP4 would normally increase by several hundred degrees because there is logic in MAAP4 to change the heat transfer mode to film boiling when the core flow is reduced below 10% of the full power flow. In order to

match the TRACG model, which is viewed as a best-estimate, the film boiling heat transfer coefficient in MAAP4 was increased to 1170 btu/hr-ft²-°F, which corresponds to the heat transfer prior to the mode change to film boiling. This condition is maintained until the core reflood begins, at which time the film boiling heat transfer coefficient is returned to its normal value. After 20 seconds, MAAP4 PCT reaches a minimum value of about 535°F and then begins to increase while the TRACG02 PCT continues to decrease until approximately 60 seconds at which time the minimum PCT is about 400°F.

In the next phase, most of the core is uncovered and there is little steam flow through the core. In this phase TRACG02 and MAAP4 PCT predictions compare rather well. The rate of heatup is virtually the same in both codes.

The final phase models the quench of the core during reflood. In MAAP4, this occurs rapidly. In this case, the PCT is fairly low so MAAP4 does not show any increase from clad oxidation during the initial reflood. In TRACG02, the initiation of core spray does not immediately quench the upper part of the core. It does, however, slow the rate of increase.

As with the BWR4 results (refer to Section B.4.2.6), to account for the model uncertainties for the BWR6, a PCT adder of 212°F was added to the TRACG02 BWR6 analysis PCT results. This results in a TRACG02 PCT of about 1634°F versus a MAAP4 PCT of about 1580°F. This shows that the PCT predicted by MAAP for the BWR6 is close, but somewhat less conservative, than the adjusted TRACG02 PCT. Both codes, however, predict a significant margin to a PCT of 2200°F.

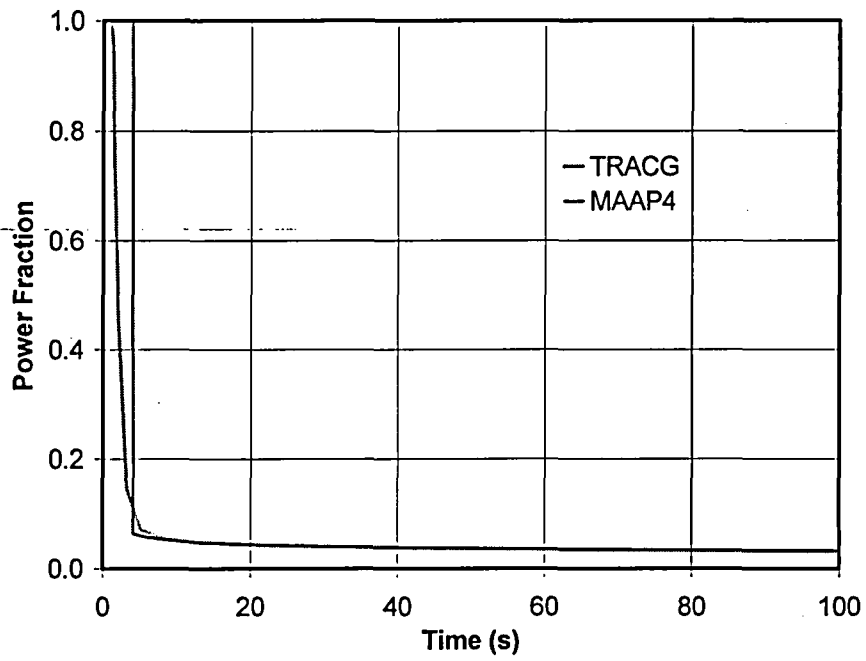


Figure B.4-6
BWR6 Case C: Reactor Power Comparison

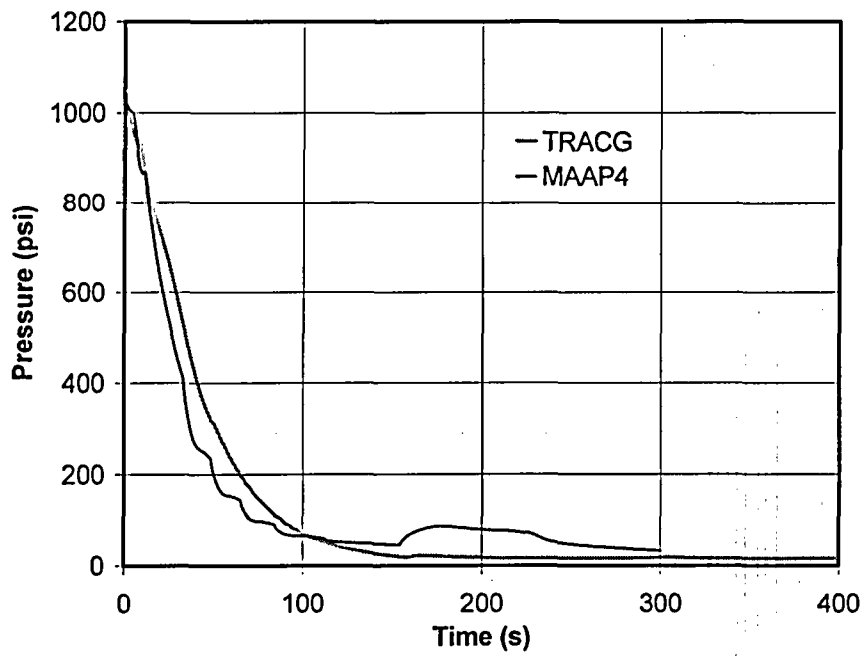


Figure B.4-7
BWR6 Case C: Reactor Vessel Pressure Comparison

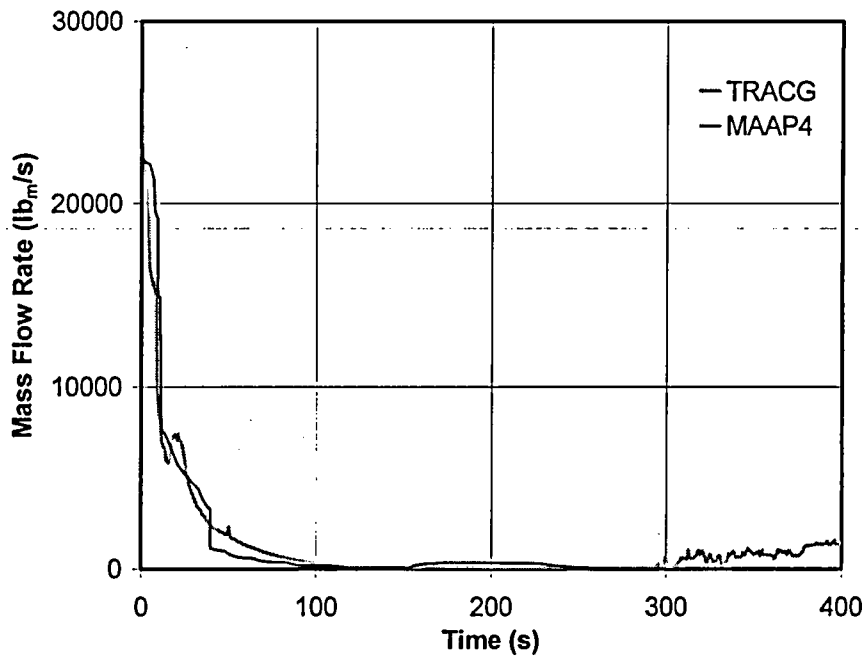


Figure B.4-8
BWR6 Case C: Break Flow Rate Comparison

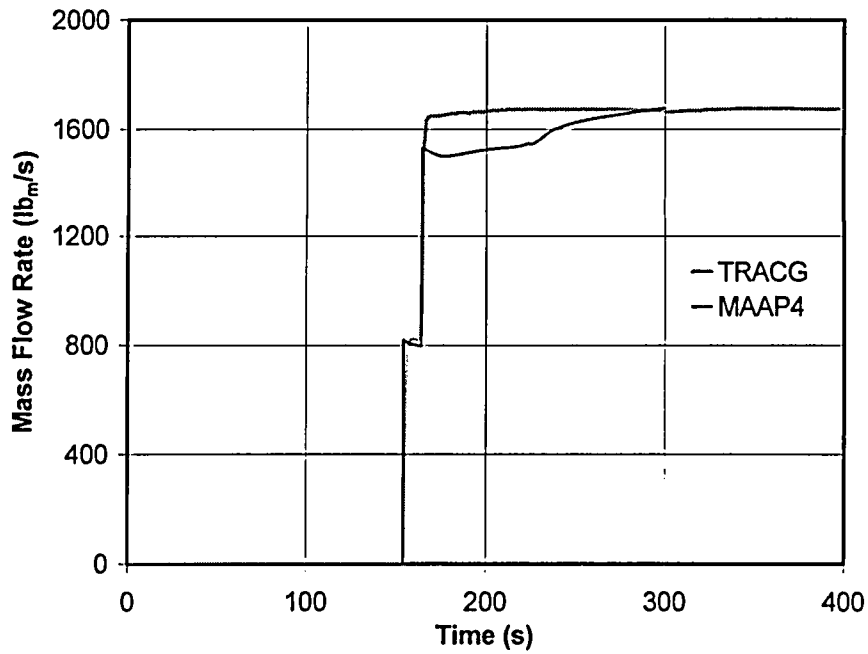


Figure B.4-9
BWR6 Case C: Total (HPCS & LPCI) ECCS Flow Comparison

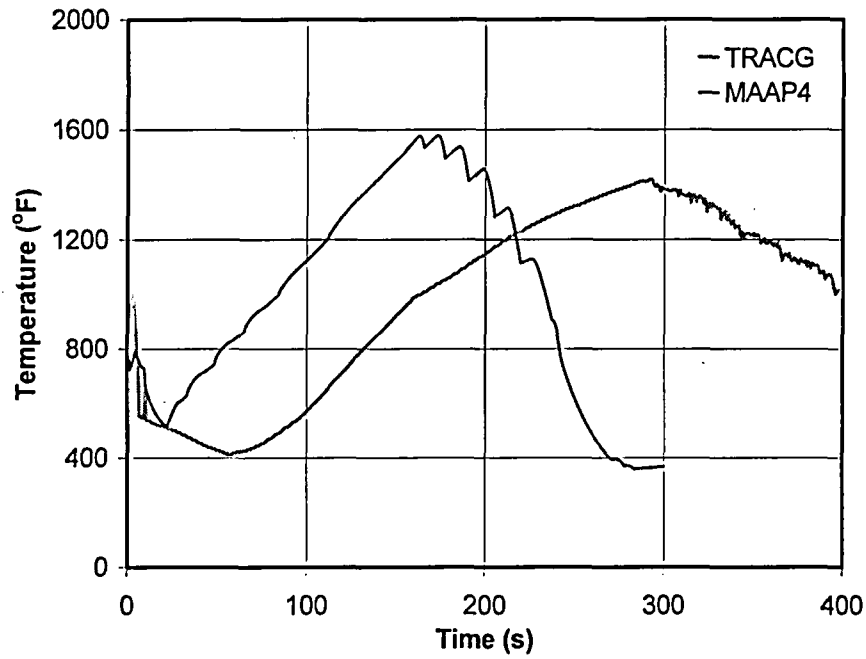


Figure B.4-10
BWR6 Case C: Peak Cladding Temperature Comparison

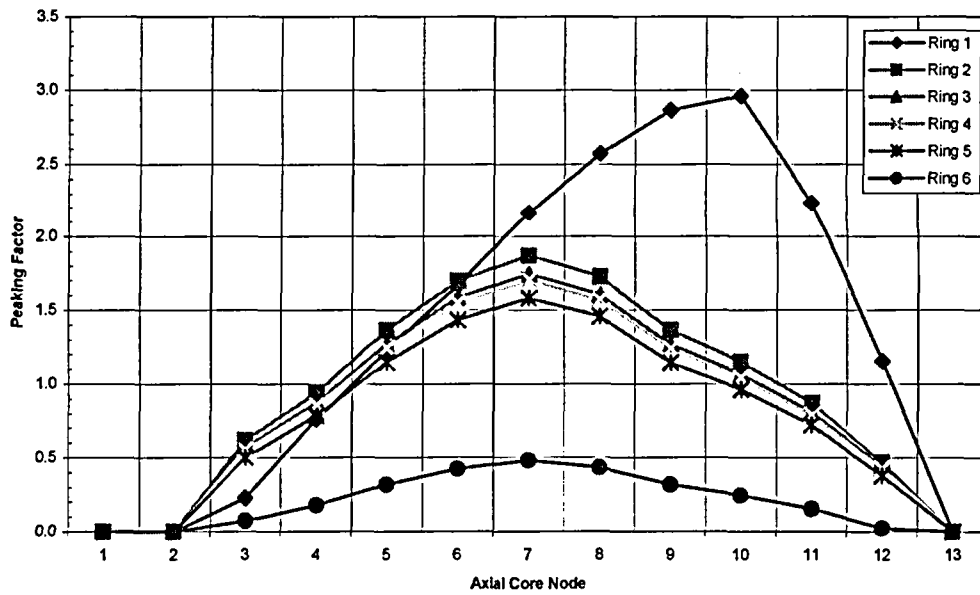


Figure B.4-11
MAAP4 Core Peaking Factors

B.4.4 Benchmark Conclusions

Sections B.4.2 and B.4.3 compare MAAP4 and TRACG02 predictions of reactor power, reactor vessel pressure, break flow rate, ECCS flow rate, and peak cladding temperature, for the selected BWR4 case and BWR6 case, respectively. Overall, the results compare favorably given the differences in methodology between the two codes. The results of these benchmark analyses conclude that MAAP4 is an acceptable tool for performing the thermal-hydraulic analyses required for the LBLOCA/LOOP exemption for the specific cases analyzed here.

B.5 MAAP4 ANALYSES FOR BWR PLANTS

B.5.1 Introduction

Section B.4 benchmarked the MAAP4 code against TRACG02 code and concluded that it is an acceptable tool for analyzing LBLOCA/LOOP events. The purpose of this section is to demonstrate that the LBLOCA/LOOP event can continue to be mitigated, even after implementing the plant modifications discussed in Section 2.4 (LBLOCA/LOOP plant changes). Each of the LBLOCA/LOOP changes and combinations were considered.

The intent of all these MAAP analyses is that any licensee may refer to these results as part of their exemption request submittal provided their plant parameters are bounded by those used for these analyses (shown in Section B.4).

These results are applicable for all BWR models except BWR2s.

B.5.2 Evaluation of LBLOCA/LOOP Changes

Utilities may choose to implement the identified plant changes in Section 2.4 of this report as a result of separation of LOOP and large break LOCA. In order to develop a set of cases for analysis it was important to evaluate the effects on ECCS equipment operation from these proposed plant changes. The anticipated plant changes, including their likely effect on ECCS equipment, are as follows:

- Allow EDG Warm Up Prior to Loading:

The expected diesel start time to facilitate warm-up would be 30 – 60 seconds.

- Optimize EDG Loading:

Automatic loading of the LPCS pump(s) or two of the LPCI pumps on the diesel generator would be eliminated. Manual start of these pumps would be expected in cases where the EPGs require maximum injection. However, this operator action was not credited in the analysis.

- Start EDGs Only When Needed:

A LOCA signal would no longer cause the start of the EDG. The EDG would start only on bus under-voltage or degraded voltage conditions.

- Simplified EDG Testing:

There are no effects on ECCS equipment response during LOCA as a result of the proposed EDG testing.

- Increased MOV Stroke Times:

Longer valve stroke times could lead to delayed injection start time.

- One Loop of RHR in Suppression Pool Cooling (SPC) Mode:

Only one loop of RHR would be available for automatic LPCI. Availability of LPCI would depend on the break location since LPCI may not be available in the broken loop.

- Eliminate LPCI Loop Select:

One loop of LPCI would inject into the broken loop. Certain scenarios could result in a loss of all LPCI.

The effects on ECCS equipment operation can be grouped into categories based on delayed or reduced injection, with a further distinction between LPCS or LPC injection. In Section 2.4 of this report, an EDG warm up time of 30 – 60 seconds is anticipated for the elimination of the fast start capability. In this analysis, EDG delay times of 90 seconds for the BWR 3/4 and 120 seconds for the BWR 5/6 were included to take into account either implementation of multiple changes or other phenomena, such as delayed LOOP. The difference in EDG delay is associated with the recirculation loop fill time in the BWR3/4 that is not present in the BWR6 LPCI design. Table B.5-1 shows the effects categorized and related to the BWR 3/4 and BWR 5/6 plant types.

B.5.3 Case Development

Based on the three (3) categories of effects identified in Table B.5-1, a series of cases was developed. Only realistic combinations of ECCS equipment availability were included. Combinations which result in a total loss of injection were not included. For instance, the combination of all three categories for a BWR 3/4 would result on a total loss of injection. The limiting combinations are listed in Table B.5-2. The following assumptions were made in developing these cases:

- Recirculation suction line break:
The event analyzed is a double-ended guillotine rupture of the recirculation suction line. A break at this location generates bounding mass and energy release rates and vessel depressurization. These conditions require the maximum ECCS flow rates to reflood the reactor core. To insure a bounding result for the BWR 3/4 plant, the break in the recirculation loop was also assumed to disable one loop of LPCI injection.
- Loss of Offsite Power:
A LOOP is assumed to occur concurrent with the ECCS injection signal, to simulate the delayed LOOP. The main feedwater pump trip is conservatively assumed to occur at the start of the event.
- ECCS Equipment Only:
No credit is taken for non-ECCS injection sources.
- Power Level:
Cases were analyzed at 105% and 125% original licensed thermal power to bound nominal and uprated plants.
- Fuel:
All cases were analyzed with GE-14 fuel with the limiting bundle on thermal limits.
- Negligible Initial Clad Oxidation:
Low initial clad oxidation leads to higher clad oxidation rates during the event.

B.5.4 ECCS Injection Line LOCAs

Breaks in an ECCS injection line were also considered in this evaluation. While it was postulated that such breaks would be less severe than the design basis recirculation line break LOCA, an analysis of a BWR6 LPCI line break was performed with MAAP4. The peak cladding temperature for this case was substantially less than any of the recirculation line break LOCA cases analyzed. This combination would be applicable to all BWR plant types.

On the basis of this analysis, it can be concluded that ECCS injection line breaks are not limiting and do not require further consideration in this evaluation.

B.5.5 Results and Conclusions

The PCT values for the MAAP4 analyses are compared in Table B.5-3 and Figure B.5-1. The PCT values all fall well below the acceptance criterion of 2200°F. The adders and other compensating factors discussed in Section B.4 were included in all of the scoping analysis cases. The highest PCT case for the BWR4 was Case A and the highest PCT case for the BWR6 was Case D.

These PCT results can be cited by licensees as part of their exemption request licensing submittal as long as their plant parameters are bounded by those used for these analyses that are documented in Table B.4-1. In such a case, plant-specific MAAP analysis will not be needed.

Table B.5-1
Bounding Representation of LBLOCA/LOOP Plant Changes

Category	Change	Effect	Bounding Effect on ECCS		
			BWR 3/4	BWR 3/4 w/ Loop-Select	BWR 5/6
1	Allow EDG Warm Up Prior to Loading	Delayed Injection	90-Second EDG Delay*		120-second EDG Delay*
	Start EDGs Only When Needed				
	Increased MOV stroke times				
2a	Optimize EDG loading	Reduced Injection	No LPCS		Loss of 1 LPCI Pump and 1 LPCS Pump
2b			Loss of 2 LPCI Pumps		
3	One loop of RHR in SPC mode	Reduced Injection	No LPCI		Loss of 1 LPCI Loop
4	Eliminate LPCI LOOP Select	Reduced Injection	N/A	Loss of 1 LPCI Loop	N/A
N/A	Simplified EDG testing	N/A	N/A		

* Nominal valve stroke and pump coast-up time assumed for ECCS equipment operation is included in addition to the EDG delay.

Table B.5-2
Limiting Combination of ECCS Delay and Reduced Injection

Case	Plant Type	Category* Combination	EDG Delay Time (sec)	Number of Injection Pumps		
				LPCI	LPCS	HPCS
A	BWR 3/4	1 & 2	90	2	0	N/A
B		1 & 3		0	2	N/A
C	BWR 5/6	1 & 2 & 3	120	1	0	1
D				2	0	0
E				0**	1	1

* Category corresponds to Table B.5-1.

** Includes an additional LPCI failure to make it a unique case.

Table B.5-3
MAAP4 PCT Comparisons of LBLOCA/LOOP Changes

Case	Plant Type	Category* Combination	EDG Delay Time (sec)	PCT (Deg. F)		
				5% Uprate	25% Uprate	Acceptance Criterion
A	BWR 3/4	1 & 2	90	1747	2002	2200
B		1 & 3		1578	1824	2200
C	BWR 5/6	1 & 2 & 3	120	1377	1554	2200
D				1458	1638	2200
E				1377	1554	2200

* Category corresponds to Table B.5-1.

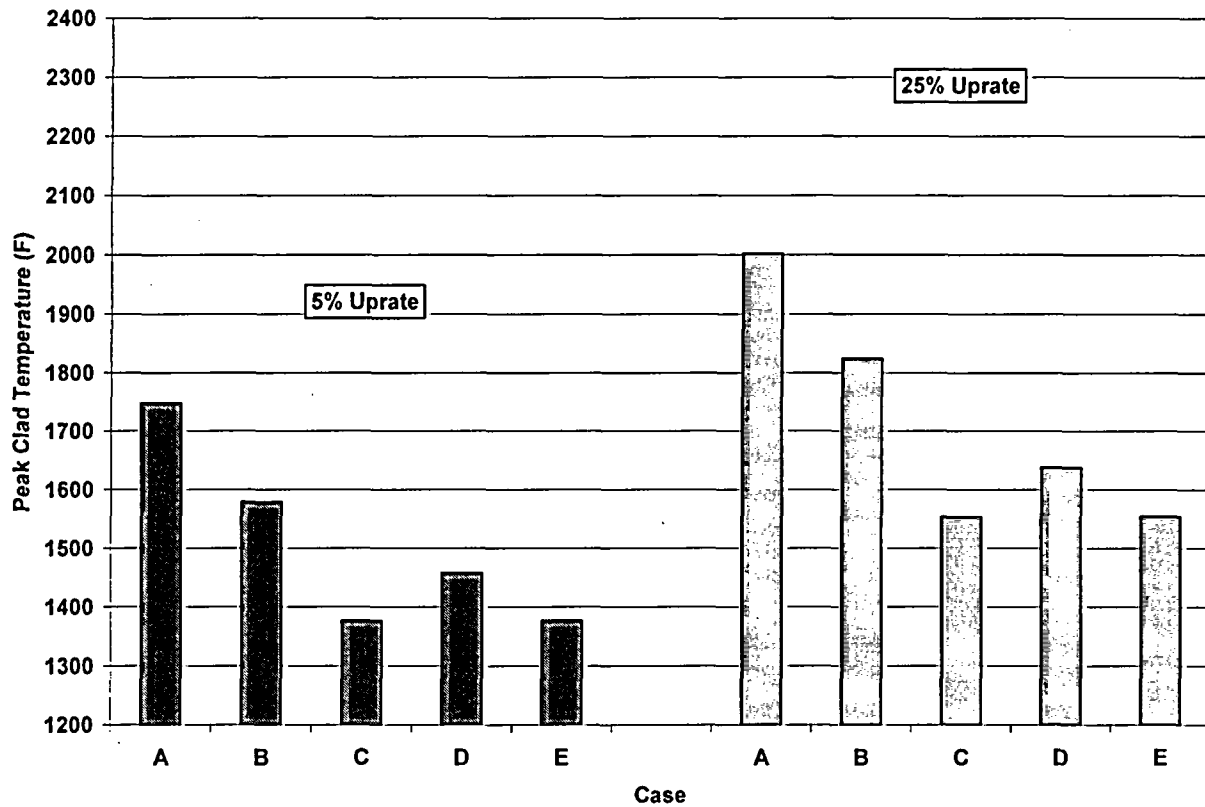


Figure B.5-1
MAAP4 PCT Comparisons of LBLOCA/LOOP Changes

Notes:

1. Refer to Table B.5-2 for a description of the Cases.
2. ECCS injection flows were not changed with power level.

B.6 MAAP SENSITIVITY ANALYSES

MAAP4 sensitivity cases were run to evaluate the impact of critical assumptions on the analyses. This was done to provide MAAP4 results for several BWR plant configurations that can be used and referenced by licensees in their exemption submittals, as long as their plant parameters fall within the bounds of the input parameters used in the generic analyses of this appendix.

B.6.1 Quench Time

The injection flow was reduced to 5-10% of design flow when the collapsed liquid level reached the core support plate. After approximately 500 seconds the injection flow was restored to the design value. The purpose of this study was to evaluate the impact of forced steam cooling on total clad oxidation with the core temperatures at or near the PCT for an extended duration. There was only a slight increase in the peak clad temperature and amount of clad oxidation. The worst-case total clad oxidation remained below 0.2%.

B.6.2 Break Size

A number of smaller break size cases were performed to evaluate the RPV depressurization rate against meeting the LPCI permissive. Slower depressurization acts to delay receipt of the LPCI permissive and to delay LPCI injection. This study demonstrated that the highest peak clad temperature occurred for the double-ended guillotine break.

B.6.3 Effect of Plant Variability

MAAP4 analysis cases A and D (refer to Table B.5-2) at the 25% uprated condition generated the highest PCT for the BWR4 and BWR6, respectively (refer to Figure B.5-1). Obviously, core power level has a strong effect on PCT following a LBLOCA with reduced and delayed ECCS injection flow. This sensitivity provides an idea of how much PCT might be expected to increase for a given plant from Original Licensed Thermal Power (OLTP) to Extended Power Uprate (EPU) conditions, which will vary depending upon specific core operating conditions.

Within a plant type there is variability in the RPV size and total ECCS injection flow. A series of runs was performed using MAAP4 to evaluate the impact of a change in RPV liquid volume with the core power level at the 25% uprated condition and ECCS injection flow unchanged. The base cases for this series of runs were Cases A and D, discussed above. RPV liquid volume, which includes the shroud, lower plenum, shroud head, separators, and active core regions, was varied $\pm 20\%$. The change in PCT for these cases was limited to approximately 100 °F for the BWR4 and approximately 200 °F for the BWR6. The largest increase in PCT occurred at lower RPV volumes (refer to Figure B.6-1).

Additional cases were analyzed to evaluate the effect of a 10% reduction in LPCI flow in conjunction with the change in RPV liquid volume. As can be seen in Figure B.6-1, the variation in LPCI flow accounted for a PCT change of approximately 25 °F for the BWR4 and less for the BWR6.

Plants with a smaller RPV tend to have a lower power level and plants with a larger RPV tend to have a higher power level. The variability cases performed in this evaluation maintained a constant power level. The effect of power level will tend to offset the impact of the variability shown in Figure B.6-1. The changes in PCT that were observed with expected variability in RPV liquid volume and LPCI flow do not alter the conclusion that margin to the objective of maintaining the core in the reactor vessel in a coolable geometry is preserved (refer to Sections B.4.2.6 and B.4.3.6). Therefore, the results of this evaluation are applicable to all BWR 3/4 and BWR 5/6 plants.

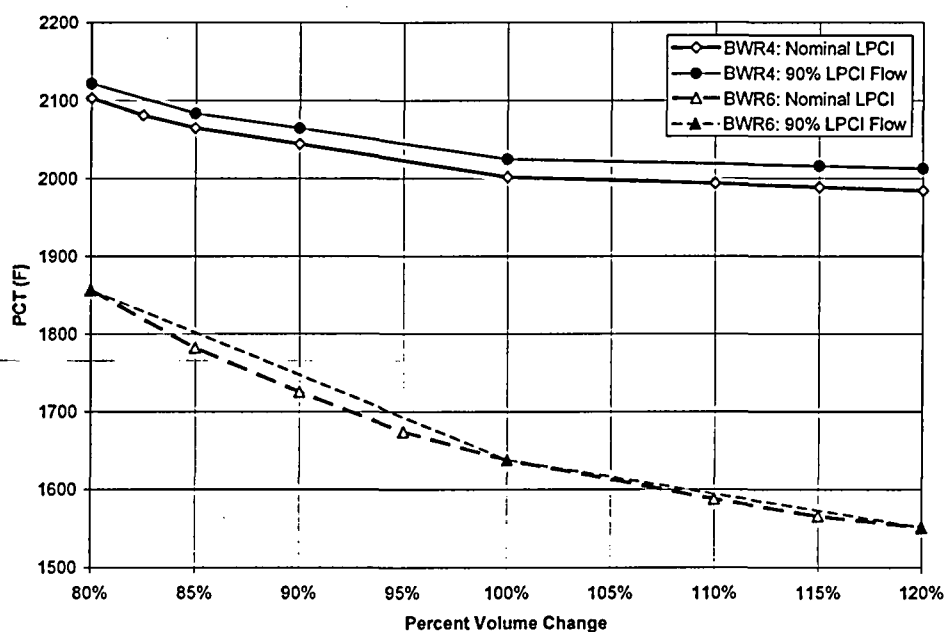


Figure B.6-1
MAAP4 Effect of Plant Variability on PCT

B.6.4 Results and Conclusions

Allowing for the variability in the parameters described above, the PCT values calculated by MAAP4 are still below the acceptance criterion of 2200 °F. Therefore, it is concluded that these results can be used and referenced by licensees in their exemption submittals, as long as their plant parameters fall within the bounds of the input parameters used in the generic analyses of this appendix.

B.7 SUMMARY & CONCLUSIONS

The objective of maintaining the core in the reactor vessel in a coolable geometry was met with significant margin. The MAAP4 cases for the limiting scenarios predict a peak clad temperature that is less than 2200 °F and no significant clad oxidation (much less than 1% global and less than 5% local clad reacted). The TRACG02 cases also predict PCT values less than 2200 °F. Therefore, the BWROG has demonstrated that defense-in-depth, as specified in RG 1.174, has been achieved, with the adoption of the LBLOCA/LOOP changes.

It is concluded that MAAP4 is an acceptable tool for performing the thermal-hydraulic analyses required for the LBLOCA/LOOP exemption for the specific cases analyzed here. As discussed in Section B.4.4, the results compare favorably between the MAAP4 and TRACG02.

It is also concluded that the MAAP4 results, provided in this appendix, are applicable to BWR 3/4/5/6 plants, as long as the plant parameters fall within the bounds of the input parameters used in the generic analyses of this appendix. If the licensee's plant meets these criteria, there is no need for additional, plant-specific thermal-hydraulic analysis to support licensee's exemption request submittal.

APPENDIX C

**GENERIC PRA EVALUATION
FOR LBLOCA/LOOP EXEMPTION**

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LIST OF ACRONYMS

Term	Definition
AC	Alternating Current
AOO	Anticipated Operational Occurrence
ARI	Alternate Rod Insertion
ATWS	Anticipated Transient without Scram
B&W	Babcock and Wilcox
BOP	Balance of Plant
BWR	Boiling Water Reactor
BWROG	BWR Owners' Group
CCDP	Conditional Core Damage Probability
CCR	Combined Change Request
CDF	Core Damage Frequency
CFR	Code Of Federal Regulations
CLERP	Conditional Large Early Release Probability
CPR	Critical Power Ratio
CRD	Control Rod Drive
CSS	Containment Spray System
CST	Condensate Storage Tank
DBA	Design Basis Accident
DC	Direct Current
DG	Diesel Generator
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPG	Emergency Procedure Guidelines
EPU	Extended Power Uprate
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GE	General Electric Company

LIST OF ACRONYMS (CONTINUE)

Term	Definition
HPCI	High Pressure Coolant Injection System
HPCS	High Pressure Core Spray
IORV	Inadvertent Open Relief Valve
IRIR	Integrated Risk Informed Regulation
ISLOCA	Interfacing Systems Loss of Coolant Accident
LBLOCA	Large-Break Loss Of Coolant Accident
LBLOCA/LOOP	LBLOCA with a Concurrent Loss Of Offsite Power
LERF	Large Early Release Frequency
LHGR	Linear Heat Generation Rate
LOCA	Loss Of Coolant Accident
LOOP	Loss Of Offsite Power
LOS	Loss of Service Water
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
LTR	Licensing Topical Report
MAAP	Modular Accident Analysis Program
MBLOCA	Medium Break Loss of Coolant Accident
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
OLTP	Original Licensed Thermal Power
PCS	Power Conversion System
PCT	Peak Cladding Temperature
PRA	Probabilistic Risk Assessment
PSS	Pressure Suppression System
PWR	Pressurized Water Reactor
RCIC	Reactor Core Isolation Cooling System
RCS	Reactor Coolant System

LIST OF ACRONYMS (CONTINUE)

Term	Definition
RG	Regulatory Guide
RHR	Residual Heat Removal
RITS	Risk Informed Technical Specification
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SBLOCA	Small Break Loss of Coolant Accident
SBO	Station Blackout
SLC	Standby Liquid Control
SORV	Stuck Open Relief Valve
SP	Suppression Pool
SPC	Suppression Pool Cooling
SRM	(NRC) Staff Requirements Memorandum
SRV	Safety Relief Valve
TBCCW	Turbine Building Closed Cooling Water
TMI	Three Mile Island
UHS	Ultimate Heat Sink

C.1 INTRODUCTION AND PURPOSE

The original LTR, "Separation of Loss of Offsite Power From Large Break LOCA", was submitted to NRC in April 2004. That LTR included a generic PRA model to represent the whole BWR fleet, which was used to calculate the risk impact of making changes to the plant associated with LBLOCA/LOOP exemption. It was initially intended that such a generic risk assessment for the BWR fleet would be sufficient. However, following NRC review and comments on the initial LTR, the BWROG agreed to revise the LTR. The revised LTR describes a risk-informed methodology that facilitates each licensee to prepare a plant-specific exemption request for the LBLOCA/LOOP event. The methodology includes steps for modeling the proposed plant changes using the plant PRA and evaluating the risk impact. The BWROG decided to include the generic PRA model and the analyses done as part of the original LTR in this appendix to provide additional guidance to the individual licensees. This Appendix includes the generic PRA model as well as the results of the PRA analyses carried out with that model. The PRA results show that the CDF and LERF increases associated with the LBLOCA/LOOP exemption and the associated plant modifications are well below the RG 1.174 guidelines.

C.2 BACKGROUND

In order to evaluate the risk changes associated with the LBLOCA/LOOP implementation described in this report, the BWROG developed a generic BWR PRA model. It is a detailed model that can be configured to represent, and provide risk insights for, most operating US BWR plants. This analysis incorporates nine different configurations of the generic BWR PRA model.

The generic BWR PRA model was created from an existing, plant-specific, peer reviewed BWR4 model. Many of the plant-specific features (i.e. those that were not broadly applicable) were removed from the model. Several features that are available at many plants were either retained or added as configuration options. This resulted in the set of models that was used to evaluate the changes in risk (CDF and LERF) that result from the LBLOCA/LOOP changes. The base BWR4 configuration is presented in Section C.3.

In the course of developing this report, the key attributes of the model were compared with the plant-specific modeling of the member BWR plants. These comparisons guided the development of the various configurations of the generic model. Section C.4 describes how the generic model was configured so that the results of this are applicable to all BWROG member plants.

Section C.5 of this appendix presents the quantitative and qualitative estimations of the risk changes associated with the LBLOCA/LOOP changes. Each of the changes is evaluated independently, and in combination with other applicable changes.

C.3 BASE PRA MODEL

The generic PRA model consists of a detailed level 1 internal events model that covers events that may occur while the plant is operating at full power. There is a simplified level 2 model that is based on an actual Mark I containment at an operating US plant. For the purposes of this application, shutdown events are not included because the ~~LBLOCA~~ with a consequential LOOP is not credible from the shutdown condition. In addition, external events are treated qualitatively.

C.3.1 System Models

This section provides a summary of the systems used in the generic PRA model. The description of each system contains attributes of the system that were considered at the time of model creation.

C.3.1.1 High-Pressure Injection Systems

There are four systems that can provide core coolant at high pressure. These are Feedwater, HPCI, RCIC, and CRD hydraulics.

The Feedwater system is assumed to be steam-driven. The main steam lines must remain open in order to take credit for this method of injection. BOP support systems, such as TBCCW and non-1E electrical busses, are also required for Feedwater. Feedwater injection also requires Condensate and Main Condenser cooling in order to operate.

BWR 4 plants that have a motor-driven Feedwater system can get more credit in their PRA than the generic model because the main steam lines are not required to be open. The remaining support systems, however, remain the same. Therefore, the generic Feedwater model bounds all plant designs.

HPCI is a steam-driven high-pressure injection system that is designed to provide emergency high-pressure injection during small LOCA accidents. It injects into the vessel outside the shroud. All of the controls for HPCI are DC powered, so the system is considered AC independent. In the generic model, however, room cooling (which is AC dependent) is required for HPCI to operate longer than 2 hours. It is possible for the operators to set up augmented cooling for the HPCI room that is independent of AC power. While this action can be taken in any accident or transient scenarios, the generic model only takes credit for this in SBO sequences.

The HPCI pump initially takes its suction from the CST. When the suppression pool level increases by about 4 inches, the suction automatically switches from the CST to the suppression pool. The time that the swap occurs is dependent on the specific accident or transient, but it is assumed to occur in less than 2 hours for all scenarios. For long-term core cooling with HPCI, SPC is required. The operators have the option to revert the water source to the CST via manual actions from the control room.

HPCI also uses a substantial amount of steam during its operation. Therefore, the generic model considers HPCI operation to be a valid means of depressurization for the plant.

RCIC is a steam-driven high-pressure injection system that is designed to provide emergency high-pressure injection following transients. It injects into the vessel outside the shroud. All of the controls for RCIC are DC powered, so the system is considered AC independent. RCIC does not require room cooling in order to operate for the long-term.

The RCIC pump initially takes its suction from the CST. When the suppression pool level increases by about 4 inches, the suction automatically switches from the CST to the suppression pool. The time that the swap occurs is dependent on the specific accident or transient, but it is assumed to occur in less than 2 hours for all scenarios. For long-term core cooling with RCIC suppression pool cooling is required. The operators have the option to revert the water source to the CST via manual actions from the control room, but containment high pressure may cause the isolation of RCIC. Containment pressure must be kept low for RCIC to operate independent of the RCIC suction source.

RCIC does not draw enough steam to depressurize the vessel to allow low-pressure injection systems to operate.

The CRD system has two pumps, with one normally in operation. Following a loss of offsite power, the system must be restarted manually. This PRA model does not take credit for CRD to prevent core damage if it is the only high-pressure injection source available.

In sequences where core injection is initially successful but subsequently fails because of suppression pool water temperature, the generic PRA model takes credit for CRD as a long-term injection system. This system takes its suction from the CST and must be aligned manually for two-pump operation. Reactor depressurization is not required for CRD to be successful. The CRD system can be powered by both onsite and offsite electrical sources and it requires instrument air to be successful.

C.3.1.2 Low-Pressure Injection Systems

There are four systems that can provide core coolant at low pressure. These are Condensate, LPCS, and RHR in LPCI mode, and Service Water.

The Condensate system has three pumps that can provide low-pressure injection as long as offsite power is available. The system takes its suction from the main condenser and makeup to the condenser is provided from the CST. When the plant is at low pressure, the condensate system can inject through the Feedwater lines.

No credit is taken for Condensate as an early injection source in LOCA sequences. If initial injection is successful, Condensate can be used for long-term cooling.

LPCS is a two-pump system that is normally in a standby condition. Upon a low reactor level signal, the system automatically starts and injects inside the shroud. This system is powered by the safety related electrical system (each division being totally independent), so it can be run using either onsite or offsite power. Room cooling is not required for the LPCS system to operate for 24 hours.

The LPCS system normally takes its suction from the suppression pool; therefore suppression pool cooling is required for LPCS to provide long-term cooling for this alignment. There is also an alternate connection to the CST that can be aligned manually. This alternate connection can only be successful for long-term cooling because of the length of time it takes to establish the lineup.

LPCI is one of the modes of the RHR system. It is normally in a standby condition. Upon a low reactor water level signal, the system automatically starts and injects into the recirculation loops. This system is powered by the safety related electrical system, so it can be run using either onsite or offsite power.

The configuration for the LPCI system is consistent with the "LPCI Mod" configuration. Each of the two loops of LPCI has two pumps, but they are each powered by a different electrical division. The injection valve for the loop is powered by 250 V DC Power. There is a crosstie between the two LPCI loops such that any of the pumps can inject into either recirculation loop. In the "LPCI Mod" configuration, however, this crosstie is locked closed. No credit is taken for the crosstie in the LPCI model.

Room cooling is not required for the LPCI system to operate for 24 hours.

The LPCI system normally takes its suction from the suppression pool, therefore suppression pool cooling is required for LPCI to provide long-term cooling. RHR is a multi-mode system that also provides suppression pool cooling. In the PRA model, it is assumed that one division of RHR can provide both coolant injection and suppression pool cooling. This can be done by either alternating the mode of the loop or by passing LPCI flow through the RHR heat exchangers. There is also an alternate connection to the CST for two of the RHR pumps, one in each loop, which can be aligned manually. This alternate connection can only be successful for long-term cooling because of the length of time it takes to establish the lineup.

In circumstances where all other low-pressure injection systems are unavailable, it is possible to align Service Water to inject into the vessel. The injection path is shared with the LPCI system. This alignment requires local manual actions, therefore is not used for early injection in LOCA sequences.

The service water system is powered by safety related electrical power, so it can be operated on either onsite or offsite power.

The event trees contain a placeholder for low-pressure injection using an AC independent Firewater system. In the base model, this node is modeled as being unavailable. It is only used in the plant configurations described in Section C.4.

C.3.1.3 Depressurization Systems

The reactor can be depressurized using any of three systems. These are the Main Steam system, SRVs, or HPCI.

The Main Steam system (which is also designated as the Power Conversion System in the logic model) normally conveys the steam from the reactor to the turbine generator. Following a plant shutdown, the turbine can be bypassed and steam is provided directly to the main condenser. In the PRA model, this system is only considered available if there is a path for water to be removed from the condenser back to the reactor vessel using Condensate pumps.

The Main Steam system operates automatically to control reactor pressure near the normal operating range for the reactor. The operators can manually adjust the system to provide depressurization.

Main Steam is automatically isolated if there is a low reactor water level signal, so no credit is allowed in small or medium LOCA sequences. In a small LOCA, Main Steam remains available as long as the high-pressure injection systems prevent the low water level signal. Main Steam is also isolated if there is a low reactor pressure if operators do not take action to prevent this isolation. This mode of isolation is not modeled because it would be modeled the same as the low level isolation. Finally, Main Steam will be isolated if the condenser is not cooled by the Circulating Water systems. Circulating Water is not powered by safety related electrical systems, therefore Main Steam is assumed to be isolated following a loss of offsite power.

SRVs provide a safety related means of depressurization. They discharge steam from the reactor to the suppression pool. The valves are DC powered and are controlled from the control room. There is an automatic mode for this system, but the PRA model assumes that this mode will be disabled by the operators (per procedure) shortly after the initiation of the accident or transient.

The HPCI system is described in section C.3.1.1.

C.3.1.4 Containment Control Systems

Containment control can be provided by either the RHR system or the containment vent.

The purpose of the containment control systems is twofold. First, the pressure inside the containment must not exceed the ultimate pressure capability of the structure. Second, the containment control systems keep the suppression pool water temperature low enough that the ECCS systems can continue injecting water into the vessel. The SPC and CSS modes of RHR perform both of these functions. The SDC mode of RHR provides both

of these functions plus the water injection function by removing heat directly from the primary system, thus preventing heat from being deposited into the containment. The containment vent system only addresses the pressure control function.

The RHR system consists of two loops with two pumps and one heat exchanger in each loop. All of the containment control functions of RHR must be manually initiated. Cooling for the heat exchangers is provided by the Service Water system.

In SPC mode, the pumps take their suction from the suppression pool, pass the water through the heat exchangers, and return it to the suppression pool. All of the pumps and valves in the system can be powered by both onsite and offsite electrical sources.

CSS mode is similar to SPC, except the water is sprayed into the containment atmosphere rather than being returned directly to the suppression pool. The CSS mode is only included in the LOCA sequences. The containment spray valves can be powered by both onsite and offsite electrical power sources. In the PRA model, CSS must be cooled by the RHR heat exchangers for the system to be considered successful.

In SDC mode, pump suction is taken directly from the reactor vessel. Flow is passed through the RHR heat exchangers and is returned to the vessel via the LPCI injection valves. Even though the shutdown cooling suction valves are not safety related, they are powered such that offsite electrical power is not required. The SDC mode is only used in non-LOCA sequences.

The containment vent can be used to control containment pressure and allow injection systems that take their suction from outside containment to be successful. The vent provides a flow path from the suppression pool air space to the plant elevated release point. The valves required for the system to succeed are a mixture of AC and DC powered valves.

C.3.1.5 Reactivity Control Systems

The primary reactivity control system is RPS. This system provides the signal and motive power to insert the control rods into the reactor. It is modeled in two parts. First is the mechanical portion that causes control rod motion. Second is the electrical portion that provides the signals to the control rod drives. These functions are independent of the other systems modeled, therefore they are modeled as undeveloped events. The probabilities for these undeveloped events are based on the Cooper Nuclear Station evaluation of RPS reliability.

The electrical portion of RPS is backed up by a manual scram of the reactor and the ARI system. These provide independent and diverse means of initiating control rod movement. The mechanical portion of RPS does not have any backup systems.

If RPS fails, reactor power can be reduced by tripping the reactor recirculation pumps, reducing water level in the reactor, and by adding dissolved boron to the reactor coolant.

The RPT function is automatic and shares much of its logic with the ARI system. It is assumed that if the signal is generated, trip of the pumps will succeed with certainty.

Reducing water level to control power is an ATWS mitigating strategy contained in the Emergency Operating Procedures. In the model, only the human action portion is included. Reducing water level may impact the way that other systems in the plant operate. The event tree models take this interaction into account.

SLC can also be used to reduce reactor power in the event that the other RPS systems fail. The system has two pumps that inject into the vessel via a single penetration. If the Main Steam system is available, one SLC pump will be sufficient to reduce power to the point where the containment integrity is protected. In Main Steam is not available, two SLC pumps are required to reduce reactor power fast enough to protect containment in all cases.

The SLC system can be powered by either onsite or offsite electrical power sources. The system must be manually initiated.

C.3.1.6 Other Front Line Systems

There are three other functions included in the PRA model. These are reactor over-pressurization-protection, re-closure of the SRVs if they open, and the Pressure Suppression System. On the event trees, these are designated M, P, and PSS respectively. All of these systems are modeled as a point estimate, and do not have detailed fault trees.

The reactor over-pressurization protection function represents the probability that one or more SRVs will open following the closure of MSIVs. If the SRVs do not open, there is a chance that the reactor vessel or the recirculation piping can be damaged or rupture. The SRVs in this function operate in safety mode, and no electrical or pneumatic support is required.

If the SRVs are postulated to open during the accident or transient, the P function models the probability that one or more of the SRVs will stick open. If this happens, some of the high-pressure injection systems are no longer considered viable. No support systems are required for the SRVs to re-close.

PSS models the chance that the pressure suppression containment may not function as designed. In LOCA sequences, this could happen if one or more wetwell to drywell vacuum breakers do not seat. If this happens, much of the steam from the reactor will not be directed below the surface of the suppression pool water and the containment pressure will quickly rise to the failure pressure. In a stuck open relief valve case, the phenomenon is a little different, but the probability is nearly the same. For these sequences, PSS is the probability that the steam discharges into the suppression pool air space. For this to happen, the tailpipe connected to the SORV would need to fail.

C.3.1.7 Support Systems

The PRA model includes several support systems. Four of these systems will be described here. These are the Service Water system, onsite AC power, offsite AC power, and DC power.

The Service Water system contains four pumps that provide water from the ultimate heat sink to cool various plant components. The system is cross-connected such that any one Service Water pump can provide cooling to any equipment. There is an interlock in the system such that header low pressure will cause the isolation of the cross connect. In the PRA model, it is assumed that this cross connect will always receive a signal to isolate. If the isolation fails, two pumps per loop are required for success. Otherwise, one pump per loop is sufficient.

When the Service Water system is providing cooling to the RHR heat exchangers or providing vessel injection, an additional set of booster pumps (two per loop) are required to increase the pressure in the RHR heat exchanger.

Onsite AC power is provided by two emergency diesel generators. Each EDG can provide power to only one safety related bus. The EDGs require service water and room ventilation in order to be successful.

Offsite AC power is provided by two nearly independent sources. First, following a turbine trip the offsite AC power is automatically transferred from the main generator to the startup transformer. This transformer is powered by the offsite grid. This transfer, called the "Fast Transfer" is bumpless and does not require any load shedding or re-starts to keep running plant equipment in their operating state. If for any reason the startup transformer fails to provide power, there is a "Slow Transfer" of the power source to the emergency transformer, which is also powered by the offsite grid, but from a different substation located several miles from the plant. The slow transfer requires that many large loads be shed from the safety busses and then be restarted in a predetermined sequence. Also, the emergency transformer only provides power to the safety related busses.

As stated above, these offsite AC power subsystems are nearly independent. If the reason for the loss of offsite power is associated with equipment failures between the plant switchyard and the plant itself, the emergency transformer provides an independent power source. If the reason that offsite power is unavailable is a result of weather (i.e. ice storms, tornado, etc.) or associated with a grid failure, then the emergency transformer is considered completely coupled with the normal offsite source.

There are two DC subsystems in the plant model. One is a 125 V system that is used for most control systems and for various valves in the plant. The other is a 250 V system that is chiefly used for HPCI and the LPCI injection valves. These are completely

independent systems; they do not share any battery cells. Each subsystem has two independent divisions.

The batteries are kept in a charged state during normal plant operation through the station battery chargers. There are three battery chargers per subsystem. Each battery has one charger in operation. Each subsystem has a swing charger that can be aligned to either battery. The swing charger is normally in a standby state. In the event of a loss of offsite power, the battery chargers are one of the loads that are stripped from the safety buses. The chargers must be manually re-aligned to their respective batteries.

C.3.2 Event Sequences

The generic model contains nine event trees. Each tree models the plant response for one or more initiating events. The nine event trees are:

- Transients
- Loss of Offsite Power
- Loss of Service Water
- Large LOCA
- Medium LOCA
- Small LOCA
- ATWS Following a Transient
- ATWS Following a Loss of Offsite Power
- ATWS Following a Large or Medium LOCA

The success criteria for each of the event trees are presented in Table C.3-1. The following sections provide a brief summary of each event tree model.

C.3.2.1 Transient Event Tree

The Transient event tree is used for initiators that involve a plant trip with offsite power available and Service Water available. These initiating events are:

- Transients with the Condenser Available
- Transients with the Condenser Unavailable
- Loss of Feedwater
- Inadvertent / Stuck Open Relief Valve
- Loss of Reactor Building Closed Cooling Water
- Loss of Instrument Air
- Loss of a Single 125 V DC Bus

- Loss of a Single Safety Related 4160 V AC Bus
- Loss of Turbine Building Closed Cooling Water
- Loss of Instrument AC Power
- Reactor Coolant Leaks

The plant response to each of these initiators is similar; however the equipment available to respond to the transient is different. The quantification of the model appropriately considers what equipment is not available as a consequence of the initiating event. The Transient Event Tree logic is shown in Figure C.3-1.

The tree starts out by determining the state of the plant. Sequences where the scram function fails are treated in the ATWS event tree (Section C.3.2.7). Sequences that involve a loss of offsite power caused by the plant trip are modeled in the LOOP event tree (Section C.3.2.2). Sequences in which the primary system ruptures due to over-pressurization are treated in the LLOCA event tree (Section C.3.2.4)*. Finally, the state of the PCS and SRVs are determined so the remainder of the progression can be determined.

For sequences with PCS available, either high-pressure injection systems need to function or the operators need to depressurize the plant. This would allow Condensate (which is implied successful by PCS success) to provide long-term injection, rejecting heat to the UHS.

For sequences in which the PCS is not available and all SRVs successfully re-close, HPCI and RCIC can provide coolant injection at high pressure. The alternative is for the operators to depressurize the plant, allowing Condensate, LPCS, LPCI, or Service Water Injection to provide coolant at low pressure. Firewater injection is also shown on the event trees, but it is only available in certain plant configurations.

For sequences in which one or more SRVs stick open (or SORV initiated events), the short-term injection response is assumed to be similar to those sequences where all SRVs re-close.

All sequences in which the PCS is not available require long-term core cooling. This involves removing heat from the containment and providing injection to the core. Containment cooling can be provided by the SPC and SDC modes of RHR. If either of these is successful, any low-pressure system available or CRD can provide long-term injection. If the containment cooling systems are not available, venting can provide containment pressure control while long-term injection must be provided from a source that is external to the containment (i.e. CST).

* If the transient initiator is a SORV, the pressure relief function (M) is assumed to be successful. To account for this, SORV initiated sequences that also have failure of M are excluded from the solution.

C.3.2.2 Loss of Offsite Power Event Tree

The LOOP event tree is used for initiators that are caused by an independent loss of offsite power, or by a transient with an induced loss of offsite power. These initiating events are:

- Grid-centered Loss of Offsite Power
- Plant-centered Loss of Offsite Power
- Weather-related Loss of Offsite Power

The following transients, combined with a consequential LOOP, are also included:

- Transients with the Condenser Available
- Transients with the Condenser Unavailable
- Loss of Feedwater
- Inadvertent Open Relief Valve
- Loss of Reactor Building Closed Cooling Water
- Loss of Turbine Building Closed Cooling Water

These transients are assumed to result in a plant trip. All other transients would involve an orderly plant shutdown, making it less susceptible to an induced LOOP.

The plant response to each of these initiators is similar; however the equipment available to respond to the transient is different. The quantification of the model appropriately considers what equipment is not available as a consequence of the initiating event. The Loss of Offsite Power Event Tree logic is shown in Figure C.3-2.

The tree starts out by determining the state of the plant. Sequences where the scram function fails are treated in the ATWS Following Loss of Offsite Power event tree (Section C.3.2.8). Sequences in which the primary system ruptures due to over-pressurization are treated in the LLOCA event tree (Section C.3.2.4)*. The state of the SRVs is determined so the remainder of the progression can be determined. The PCS is not available in LOOP sequences. Finally, the availability of onsite power is checked to separate the SBO from non-SBO sequences.

For non-SBO sequences in which all SRVs successfully re-close, HPCI and RCIC can provide coolant injection at high pressure. The alternative is for the operators to depressurize the plant, allowing LPCS, LPCI, or Service Water Injection to provide coolant at low pressure. Firewater injection is also shown on the event trees, but it is only available in certain plant configurations.

* If the transient initiator is a SORV, the pressure relief function (M) is assumed to be successful. To account for this, SORV initiated sequences that also have failure of M are excluded from the solution.

For non-SBO sequences in which one or more SRVs stick open (or SORV initiated events), the short-term injection response is assumed to be similar to those sequences where all SRVs re-close.

All non-SBO sequences require long-term core cooling. This involves removing heat from the containment and providing injection to the core. Containment cooling can be provided by the SPC and SDC modes of RHR. If either of these is successful, any low-pressure system available or CRD can provide long-term injection. If the containment cooling systems are not available, venting can provide containment pressure control while long-term injection must be provided from a source that is external to the containment (i.e. CST).

In SBO sequences, only AC independent systems (and Firewater, if the specific configuration includes that system) are available. These systems must provide both short-term cooling and long-term injection. If AC power is not recovered, these sequences will result in core damage.

C.3.2.3 Loss of Service Water Event Tree

The Loss of Service Water event tree provides a simplified evaluation of this event. The logic is presented in Figure C.3-3.

Short-term injection is not included in the model because the effects of LOSW would not be realized for several hours into the event. The equipment failures are already included in the Transient event tree, which has an initiating event frequency that is more than three orders of magnitude higher than the LOSW event. Therefore, including those same failures in this model would not provide any significant change in CDF or provide any additional insights. ATWS and LOOP sequences combined with the LOSW are also implicitly treated elsewhere in the model.

Long-term cooling can only be provided by the containment vent in conjunction with a low-pressure injection source from outside the containment.

C.3.2.4 Large LOCA Event Tree.

The Large LOCA event tree models events initiated by breaks in the primary system that are large enough to depressurize the plant to the point where low-pressure systems can inject prior to core damage. No high-pressure injection is credited in this analysis. The logic for LBLOCA events is presented in Figure C.3-4.

ATWS following LBLOCA is analyzed in Section C.3.2.9.

The break in the primary system is assumed to be in a recirculation line. Any injection system that relies on the integrity of that line is assumed to be unavailable in the analysis.

Short-term low-pressure injection can be provided by LPCS or LPCI, with suction from the suppression pool only. Containment cooling can be provided by the SPC and Spray

modes of RHR. If short-term injection is successful, but containment cooling is not, long-term injection can be provided by venting the containment and aligning any of the low-pressure systems that take suction from outside the containment.

C.3.2.5 Medium LOCA Event Tree

The Medium LOCA event tree models events initiated by breaks in the primary system that are large enough that RCIC cannot prevent core damage, but small enough that HPCI can provide enough flow to prevent core damage prior to low-pressure system initiation. The logic for MBLOCA events is presented in Figure C.3-5.

ATWS following MBLOCA is analyzed in section C.3.2.9.

The location of the break in MBLOCA is assumed to be in a recirculation line, but this assumption does not have any affect on the progression of the event.

Short-term high-pressure injection can be provided by HPCI. If it fails, the plant must be depressurized through the SRVs in order for low-pressure systems to be successful. Short-term low-pressure injection can be provided by LPCS or LPCI, with suction from the suppression pool only. Containment cooling can be provided by the SPC and Spray modes of RHR. If short-term injection is successful, but containment cooling is not, long-term injection can be provided by venting the containment and aligning any of the low-pressure systems that take suction from outside the containment.

C.3.2.6 Small LOCA Event Tree

The Small LOCA event tree models events initiated by breaks in the primary system that are large enough that CRD cannot provide makeup and small enough that RCIC can provide enough flow to prevent core damage. The logic for the SBLOCA events is presented in Figure C.3-6.

ATWS following SBLOCA is analyzed along with the transients in section C.3.2.7.

The location of the break in SBLOCA is assumed to be in a recirculation line, but this assumption does not have any affect on the progression of the event.

The PCS and Feedwater systems can be successful in preventing core damage in a SBLOCA. Other high-pressure systems available are HPCI and RCIC. If the high-pressure injection systems fail, the plant must be depressurized either by the PCS or via the SRVs. This will allow low-pressure systems to provide core cooling. In this event tree, the only low-pressure systems that are available for short-term low-pressure injection are LPCS and LPCI with suction from the suppression pool.

Containment cooling can be provided by either the SPC or Spray modes of RHR. If these are not successful, long-term cooling can be satisfied by venting the containment and injecting water from a source outside containment. The available long-term injection

systems include Condensate, Service Water, and Firewater (if present in the specific configuration), in addition to LPCS and LPCI with suction from the CST.

C.3.2.7 ATWS Following a Transient Event Tree

The ATWS following a transient event tree models the response of the systems and operator actions needed to control reactivity in the core and the amount of heat deposited into the containment. The logic for this event tree is presented in Figure C.3-7.

The function of the control rods is split into two different top events: mechanical and electrical. Mechanical includes the reliability of the rods themselves and the scram discharge volume. It is assumed that mechanical failure of the control rods does not have any backup. Electrical failure is backed up by ARI and by a manual scram signal.

It is assumed that failure of the electrical portion of RPS and its backups will lead directly to core damage. This is conservative, because as can be seen below, there are other means of controlling power. This assumption is tolerable because of the high reliability of the electrical portion of RPS and its backup systems.

If the control rods do not stop the nuclear reaction in the core, power can be reduced by several other means, including trip of the recirculation pumps, injection of boron into the primary system coolant, or reduction of water level in the reactor.

Short-term injection systems available are Feedwater and HPCI, and LPCS and LPCI provided the reactor is depressurized. It is assumed that these are only available if boron is injected into the coolant. Containment cooling is provided by the SPC mode of RHR.

If boron is injected into the reactor coolant and at least one of the injection systems listed above is available, long-term cooling can be provided by any of the available low-pressure systems that take suction from outside the containment in conjunction with the containment vent.

C.3.2.8 ATWS Following a Loss of Offsite Power Event Tree

The ATWS following a LOOP event tree models the response of the systems and operator actions needed to control reactivity in the core and the amount of heat deposited into the containment. The logic for this event tree is presented in Figure C.3-8.

This event tree is similar to the ATWS following a transient event tree, except Condensate is not available for long-term cooling.

C.3.2.9 ATWS Following a Large or Medium LOCA Event Tree

The ATWS following a LBLOCA or MBLOCA event tree models the response of the control rods following one of these LOCAs. The logic for this event tree is presented in Figure C.3-9.

It is assumed that if the control rods do not go into the core and shut down the nuclear reaction following large or medium LOCA, core damage will occur.

C.3.3 Initiating Events

The initiating events that were evaluated in the generic model were the following:

- Transients with the Condenser Available
- Transients with the Condenser Unavailable
- Loss of Feedwater
- Inadvertent Open Relief Valve
- Loss of Reactor Building Closed Cooling Water
- Loss of Instrument Air
- Loss of a Single 125 V DC Bus
- Loss of a Single Safety Related 4160 V AC Bus
- Loss of Turbine Building Closed Cooling Water
- Loss of Instrument AC Power
- Reactor Coolant Leaks
- ~~Small LOCA~~
- Medium LOCA
- Large LOCA
- Loss of Service Water

The values used for these initiators were derived from NUREG/CR-5750 (Reference C-1). Table C.3-2 provides the frequencies and distributions for all of the initiating events. The BWROG has determined that this reference provides the best representation of initiator values that are applicable across the fleet.

As part of the benchmark analysis (Section C.4), BWROG member plants were asked to provide the values that they used for several initiating events. These were Large LOCA, Medium LOCA, Small LOCA, and LOOP. Figures C.3-10 through C.3-13 show the ranges of these initiator values.

These figures show that there is quite a wide variation in many of the initiator frequencies, especially in the area of LOCA. Medium LOCA has the widest variation. This variation is expected because of the lack of LOCA data. Many of the plants use values that are consistent with the values used in the generic model. A sensitivity analysis was performed to analyze the variation in the LOCA frequencies.

C.3.4 Quantification

The generic model and its variations were quantified using a linked fault tree method. All of the event trees described in Section C.3.2 were quantified with the top event fault trees fully linked into the model. Deleting the cutsets that would be subsumed by the applicable top event fault tree simulated success branches. Complement events were not used in generating the model solution.

The truncation value used in the quantification was 1×10^{-12} per year. In order to retain all of the necessary terms for sensitivity analyses, in addition to the low truncation level the initiating event frequencies were set to the highest value reported by either BWROG member utilities or the 95th percentile from NUREG/CR-5750 (Reference C-1), whichever is higher. Following quantification, the initiator values were then restored to their mean values.

Following generation of cutsets for each sequence, all of the sequence results were combined into a single cutset list. This list was then passed through the "subsume" process to ensure that only minimal cutsets were retained. This step is necessary because of the way that success branches in the event tree are solved.

Table C.3-3 shows the results for all of the model configurations that were quantified.

C.3.5 Simplified Level 2

The generic model uses a simplified Level 2 analysis. It is derived from a plant-specific Level 2 analysis of a member utility, which was developed using a fully developed set of containment event trees. The simplified analysis used in the generic model represents a Mark I containment configuration. It is assumed that the use of this configuration bounds the LERF value for other BWR containment designs.

The Level 2 model only estimates the LERF value for the generic model. No other release modes are addressed.

LERF is estimated as follows. First all of the core damage sequences are gathered into plant damage state bins. All of the sequences in a particular bin have a similar progression of events and phenomena. The frequency of core damage for each of the bins is estimated by summing the CDF for the sequences collected into the bin. A conditional probability of large early release given core damage of the type defined by the bin is obtained from the plant-specific Level 2 analysis. The frequency of the PDS bin is then multiplied by the conditional probability of a large early release associated with the bin. Total LERF is obtained by summing the LERF values for all PDS bins.

The definition of the PDS bins and the associated conditional probability of large early release is shown in Table C.3-4.

C.3.6 External Events

There are several initiating events that are not affected by the changes proposed by this report. These are internal fires, internal flood, and seismic events. This section provides a qualitative discussion of these events. ISLOCA is also discussed in this section. Other external events have been postulated for BWRs, but they do not significantly impact CDF or LERF*.

There are no credible fire events that can cause a LBLOCA, therefore the proposed changes to the operation and initiation of diesel generators will not have any detrimental affect. The improved reliability of the EDGs, however will have a beneficial effect on any fire event that results in a loss of offsite power. The changes that involve optimizing EDG loads and the configuration of RHR systems only affect a small portion of the ECCS available during LOOP events, but provide other benefits to offset the reconfiguration. A review of the importance measures for the base model and the variations confirms that these changes also have a beneficial effect on LOOP events, and by implication, fire events that result in a LOOP. It is judged that the changes proposed in this report will result in a reduction in risk for all fire initiating events.

Internal flood events are similar. There are no credible flood events that can cause a LBLOCA, therefore the proposed changes to the operation and initiation of diesel generators will not have any detrimental effect. It is also not likely that a flood will cause a loss of offsite power. If it did, the improved reliability of the EDGs will be beneficial in these particular flood sequences. It is judged that the changes proposed in this report will result in a reduction in risk for all internal flooding events.

Seismic events can cause a loss of offsite power at a BWR. For the same reasons described above, the changes proposed in this report will have a beneficial effect on these seismic events. If the magnitude of the event is large enough, it is possible that the primary system piping could be damaged*. The typical construction of BWRs is such that any earthquake that can cause a LBLOCA will also cause failure of the EDGs. Therefore, there would be no change in the CDF associated with very large seismic events. It is judged that the changes proposed in this report will result in a reduction in risk for seismic initiated events.

NUREG/CR-5750 (Reference C-1) cites the ISLOCA event frequency for BWRs as being less than 1×10^{-8} per year. This combined with the probability of failure to isolate the break (typically 0.1) and the conditional probability of LOOP (0.01) places this event frequency well beyond the realm of consideration for this report. It is judged that the

* Severe weather, such as hurricanes, is included in the Loss of Offsite Power initiating event.

* Seismic events of a magnitude great enough to damage the primary system is beyond the design basis at nuclear power plants.

changes proposed in this report will result in a negligible change in risk due to ISLOCA events.

C.3.7 Component Failure Data

The failure data for ECCS equipment used in this evaluation was taken from the draft MSPI user manual, Appendix F (Reference C-2). This data is considered to be acceptable performance for ECCS equipment at nuclear power plants. In addition, any other non-ECCS components that were the same type (e.g. MOV) as ECCS equipment used the same failure rates.

The unavailability data for ECCS equipment used in this evaluation was derived from the 3rd quarter 2003 Reactor Oversight Process reported data for BWRs.

The balance of the failure and unavailability data was taken from the plant from which the generic model was derived. In addition, common cause factors were taken from the underlying plant-specific model.

All mission times were assumed to be 24 hours, even though not all equipment is required to run for the full 24 hours for each sequence. This provides a conservative estimate of the associated CDF.

C.3.8 Uncertainty Analysis

In order to provide more confidence in the model results, a numerical uncertainty analysis was performed on each of the BWR 4 and BWR 6 model configurations. The method chosen was Monte Carlo. Figures C.3-14 through C.3-19 show the results of these evaluations.

The results of this analysis are as expected. The ratio of mean to 5th percentile ranges from a factor of 5 to 15, and the ratio of 95th percentile to the mean is approximately a factor of 3. The CDF calculated using the mean values of all data lies near the mean value of the calculated distributions. This is typical of internal events PRA analyses.

C.4 BENCHMARK WITH BWROG PLANT-SPECIFIC ANALYSES

In order to ensure that the conclusions of this report are applicable to all BWRs, the generic model results were compared to the plant-specific PRA results for several BWRs. When a plant attribute was identified that caused significant differences in the calculate CDF, a version of the generic model was created that would address that particular difference. In all, four distinct plant configurations (in addition to the base model described in C.3) were identified:

- BWR 5/6 ECCS Configuration
- BWR 3/4 with LPCI Loop-Select Logic
- AC Independent Low-Pressure Injection System
- Additional Independent AC Power Source

These are described in the sections below.

In addition, one other factor was identified that has an effect on CDF. This is station battery life. The generic model assumes a nominal four-hour battery life for the station batteries. Plants whose batteries discharge over a greater time period tend to have a significantly lower CDF, while those that do not last as long tend to have a higher CDF. The reason for this difference is associated with the value applied for offsite AC power recovery.

The comparisons performed in this section were done based on conditional core damage probability (CCDP). This was done to eliminate the effects of different initiating event data, and is more useful for comparing the model logic. In this section, CCDP is calculated by taking the CDF for a particular event tree and dividing by the value of the initiating event frequency.

Most of the comparisons were made using the Loss of Offsite Power event tree. The reason for this is that, in general, this initiator is responsible for the greatest fraction of CDF at BWRs. In addition, many of the changes described in this report affect only the LOOP events. It is assumed that if the CCDP for LOOP events match between a plant-specific model and the generic model, the CCDP for other transients will also be similar.

C.4.1 BWR 6 Model

One obvious configuration difference is the design of the ECCS in the BWR 5/6 class of plants. In this configuration, there is only one LPCS pump. It is assumed to be powered by electrical division I.

There are 3 LPCI pumps; one powered by division I, and two by division II. These pumps inject directly into the core via three separate injection lines, rather than into the

recirculation loops. In this configuration, none of the LPCI loops are affected by the LBLOCA initiator. Two of the pumps, one on each division, can also be used for suppression pool cooling, shutdown cooling, or containment spray.

The BWR 6 does not have a HPCI pump. Instead, it has a High Pressure Core Spray (HPCS) pump that is powered by offsite power or by a dedicated diesel generator. Because it is a motor driven pump, it is capable of long-term injection in all sequences, including LBLOCA and MBLOCA.

C.4.2 BWR 4 with LPCI Loop-Select Model

The LPCI loop-select model was created to explicitly evaluate the elimination of the loop-select function. In this model, flow from any of the four RHR pumps can be directed to the core via the intact recirculation loop. A basic event is included that accounts for the failure of the loop-select logic, which would fail all LPCI injection during a LBLOCA.

The other difference is that the RHR pumps are not arranged with a cross-divisional electrical configuration. All of the equipment in loop A is powered by division I electrical, and all of the equipment in loop B is powered by division II electrical.

The loop-select portion was only included in the LPCI fault tree for LBLOCA early injection. The electrical configuration was included for all modes of RHR operation.

C.4.3 AC Independent Low-Pressure Injection Model

Many BWRs have the capability to inject at low pressure using an AC independent system, such as a diesel driven firewater pump. This capability can significantly reduce the CDF for many core damage sequences, especially station blackout sequences. The generic PRA model includes a configuration that takes credit for this capability.

The AC independent system is modeled using a diesel-driven pump that takes suction from the CST. It shares an injection path with a loop of LPCI, incorporating a local manual action to open the injection valve. This system is started and aligned manually. In order for it to be successful, the reactor vessel must be depressurized and the containment vent must operate successfully. In order to assure the condition of containment venting, the vent model was changed so that it could be operated using only DC electrical power.

The AC independent low-pressure injection model is not used as an early injection system for LOCA, SORV, or ATWS events. It is assumed that the local manual actions that must be taken to align the system could not be successful within the timeframe needed for early injection.

C.4.4 Additional Independent AC Power Source Model

Some BWRs have additional capability to provide AC power to some of their plant equipment during station blackout events. Examples of these are SBO diesels or black start combustion turbine generators. In order for this capability to significantly reduce the CDF at a plant, it must be independent of the station's emergency diesel generators to the extent that modeling common cause between the extra AC power source and the EDGs would not be warranted.

The additional independent AC power source in the generic model has the capacity to power one division of safety related electrical equipment. Alignment of the system must be performed manually, and it can be accomplished within a short period following the SBO such that early injection can be performed successfully. This last assumption has a small non-conservative effect for LBLOCA and MBLOCA events, however the contribution of LBLOCA SBO and MBLOCA SBO events is so small that the effect is negligible.

C.4.5 Offsite Power Configuration

There are several different configurations for connecting to the offsite power grid at the various BWR plants. All of them, however, must comply with GDC-17 requirements. The relevant attribute is that there are two independent means of providing offsite AC power to the safety related buses. This section provides an overview of different configurations and their affect on the PRA results.

The generic PRA model has an offsite power model that has the following attributes:

- Main switchyard with multiple connections to a 345 kV grid
- Alternate switchyard with a single connection to a 69 kV grid
- During operation, all onsite power is provided by the main transformer
- Following a turbine trip, transfer relaying is required to supply offsite power
- Interlocks prevent bus connections to multiple sources, either onsite or offsite
- DC power is required to transfer the power source

There are three ways that offsite power can be lost at a plant. These are called "Plant-centered", "Grid-centered", and "Weather-related" events. Each one has a different potential for recovery of offsite power. Additionally, the connection to offsite power can be lost following a plant transient because of electrical transfer failures.

Plant-centered events are caused by faults or failures that may occur between the main switchyard and the main or startup transformer while the plant is operating. For this type of event, the alternate switchyard is a completely independent offsite power source.

Grid-centered events are caused by instabilities or breakdown of the 345 kV grid. The alternate switchyard is assumed to be completely dependent on the 345 kV grid, so if the event is grid-centered, the alternate source is not available. The conditional loss of offsite power events (LOOP given LOCA and LOOP given transient) are modeled as grid-centered events.

Weather-related events are caused by severe weather in the vicinity of the plant. In this case, the alternate switchyard is also disabled with certainty by any severe weather events that cause a loss of the main switchyard.

When an accident or transient event occurs at the plant, the main turbine is tripped. This causes a transfer of the AC power source to the offsite power grid. If the equipment that is required for this transfer fails to operate correctly, the event is treated as a plant-centered loss of offsite power in the generic model. This portion of the model includes the transfer breakers, under-voltage relays, and interlocks. Note that these events are not the same as conditional LOOP events mentioned above, because they affect only plant equipment and not the grid as a whole.

The transfer from the main transformer to offsite power sources requires several breakers to change state. These breakers use 125 VDC for control power, so if the batteries fail or are not available, the transfer cannot occur. If the initiating event is a loss of DC power, it is assumed that the operators can attempt a manual reconfiguration of offsite power prior to tripping the main generator.

Figure C.3-2 shows the generic model logic for loss of offsite power events.

Review of the generic model cutsets indicates that the specific configuration of the connection from the switchyard(s) to the plant power system is not critical to the results, so long as it is reliable and robust. The generic model contains the same types of failure modes that are present at all plants, so it is considered applicable across the fleet.

Some plants have multiple main switchyard configurations. These configurations can introduce a different dominant LOOP initiating event, the partial LOOP. This configuration has a significant effect only on the plant-centered loss of offsite power events. For plants with this configuration, the frequency of the partial LOOP tends to be higher than a full LOOP. Based on the survey responses, plants with this configuration have a partial LOOP frequency that looks similar to the full LOOP frequency used in the generic model. If there is a partial LOOP, the plant retains approximately half of its offsite powered equipment available for mitigation, therefore the CCDP for these sequences would be smaller. It is appropriate, for the purposes of this analysis, to use a

single full LOOP frequency in the generic model to cover both full and partial LOOP events.

C.4.6 Benchmark Summary

The CCDP estimated for different plant configurations were compared to plant-specific results for several BWROG member plants. The comparison was made using the LOOP and MBLOCA event trees. The response to the LOOP initiating event provides most of the CDF difference for the changes described in this report. The MBLOCA comparison was done chiefly to validate that the BWR 6 configuration gave appropriate results.

Figure C.4-1 shows the comparison results for the LOOP event trees. With two exceptions, the generic PRA model results are consistent with all plant configurations. The two exceptions are different because of conservative modeling assumptions associated with the recovery of failed onsite power equipment. This analysis shows that the generic model can accurately estimate a plants response to LOOP events, as long as the key assumptions are consistently applied. The variations within the plant configuration groups are mainly a function of station battery life. If the plant is able to cope longer without AC power, the non-recovery factors that can be applied to station blackout sequences would be lower. The range of CCDP values seen are consistent with the time dependence on the offsite power non-recovery factors used in the generic model.

Figure C.4-2 shows the comparison results for the MBLOCA event trees. Once again, the comparison holds for most plants. The magnitude of the two exceptions is not sufficient to affect the overall model results. Because the conclusions drawn in this report are not as sensitive to the MBLOCA model, no further breakdown in configuration type is necessary.

C.5 RISK CALCULATION FOR PLANT CHANGES

This section outlines the changes that were made to the model to address the LBLOCA/LOOP modifications described in this report. They are first addressed individually in sections C.5.1 through C.5.5, then the combination of changes are discussed in C.5.6.

Each change is evaluated in the following manner:

- (1) Calculate the CDF and LERF for the base (unaltered case)
- (2) Calculate the CDF and LERF following the change
- (3) Delete any contribution for LBLOCA/LOOP from the changed CDF calculated in (2)
- (4) Subtract the results of (1) from (3). This represents the CDF improvements caused by the change that offsets a portion of the assumed 10^{-6} increase associated with eliminating the LBLOCA/LOOP requirement
- (5) Subtract the LERF results of (1) from (2). This is an approximation of the offset in LERF

In this report, any values less than 5×10^{-10} will be reported as "ε" and should be considered negligible. Offsets are assumed to be risk decreases. Any change that results in a risk increase will be presented in parentheses.

C.5.1 Optimize EDG Loading

In the description of the changes, it was postulated that LPCS or some LPCI pumps could be eliminated as equipment that is automatically loaded on to the diesel generators, while battery chargers could be added. This provides a trade-off. If the chargers are automatically loaded on the emergency buses, the operator actions associated with DC load shed or re-start of the chargers would be rendered unnecessary. Low-pressure ECCS pumps that are not automatically loaded following a loss-of-offsite power could be subsequently added manually in the event that other systems were unable to provide core injection.

The PRA model was modified to address these configurations. The 125 V DC model was changed such that if offsite power were lost, the operator action to load the chargers would be eliminated from the model. The LPCS model was changed by adding an operator action to manually start these pumps following a loss of offsite power. The LCPI model was changed in a similar manner, but the operator action was only included for two of the four LPCI pumps. Either the LPCS or the LPCI change can be made, but not both.

Eight plant configurations were evaluated for each of the optimizations. These are presented below. In the case of the BWR6 model, the elimination of the automatic start of LPCS following LOOP includes one division of LPCI. This is to balance the load on the EDGs.

Configuration	CDF Offset for Disabling LPCS Automatic Start Following LOOP	CDF Offset for Disabling LPCI Automatic Start Following LOOP
BWR 3/4 Base	1.2×10^{-8}	1.4×10^{-8}
BWR 3/4 with AC Independent LP Injection	3.0×10^{-8}	3.0×10^{-8}
BWR 3/4 with Independent AC Power Source	3.0×10^{-9}	4.0×10^{-9}
BWR 5/6 Base	1.3×10^{-8}	1.3×10^{-8}
BWR 5/6 with AC Independent LP Injection	3.3×10^{-8}	3.3×10^{-8}
BWR 5/6 with Independent AC Power Source	3.0×10^{-9}	4.0×10^{-9}
BWR 3/4 with LPCI Loop-Select and AC Independent LP Injection	2.0×10^{-8}	2.1×10^{-8}
BWR 3/4 with LPCI Loop-Select and Independent AC Power Source	2.0×10^{-9}	3.0×10^{-9}

All LERF offsets associated with this change are negligible.

C.5.2 One Loop of RHR in Suppression Pool Cooling Mode

Another postulated change was to start one loop of RHR in suppression pool cooling mode rather than LPCI mode. With this change, the operators would not need to start suppression pool cooling for scenarios in which the pool water temperature increased above a given value. If the other core injection systems were not available, the loop selected for automatic SPC could be manually aligned to the LPCI mode instead.

In the PRA model, eliminating the operator action from one loop of RHR for suppression pool cooling simulated this change. An operator action to manually start the loop in LPCI mode was added to the LPCI model for the affected loop. The other loop retained the original configuration.

Eight plant configurations were evaluated for this change. These are presented below.

Configuration	CDF Offset for Automatically Starting One Loop of RHR in SPC Mode
BWR 3/4 Base	4.1×10^{-8}
BWR 3/4 with AC Independent LP Injection	6.0×10^{-9}
BWR 3/4 with Independent AC Power Source	3.6×10^{-8}
BWR 5/6 Base	3.7×10^{-8}
BWR 5/6 with AC Independent LP Injection	2.0×10^{-9}
BWR 5/6 with Independent AC Power Source	3.5×10^{-8}
BWR 3/4 with LPCI Loop-Select and AC Independent LP Injection	3.0×10^{-9}
BWR 3/4 with LPCI Loop-Select and Independent AC Power Source	3.5×10^{-8}

All LERF offsets associated with this change are negligible.

C.5.3 Eliminate LPCI Loop-Select

In the past, LPCI Loop-Select has been removed from BWRs through elaborate redesign and reconfiguration. The change proposed here is to eliminate the feature in a straightforward manner. The cross-tie valve would be locked closed, and the logic would be disabled. If there is a LBLOCA in one of the recirculation lines, all of the ECCS flow through that line is assumed to be lost.

For this change, only two configurations needed to be evaluated.

Configuration	CDF Offset for Eliminating LPCI Loop-Select Logic
BWR 3/4 with LPCI Loop-Select and AC Independent LP Injection	(1.0×10^{-9})
BWR 3/4 with LPCI Loop-Select and Independent AC Power Source	(2.0×10^{-9})

All LERF offsets associated with this change are negligible.

Even though this change presents a very small increase in CDF, it is noteworthy that the final configuration is still less than the base case for the "LPCI Mod" plants. Therefore, eliminating LPCI in this manner seems to be more risk beneficial than what has been done in the past in a deterministic manner.

C.5.4 Allow EDG Warm Up Prior to Loading

It is difficult to predict the actual reduction in unavailability and unreliability of the diesel generators associated with the proposed changes. The effect is not expected to be large, but even small improvements can substantially offset the postulated risk increase arising from the assumption that all LBLOCA/LOOP events result in core damage.

A reasonable reduction in unavailability and failure rates as a result of the changes described in this report would be 10%. For example, the average unavailability of EDGs is 1.0×10^{-2} . Assuming an average annual required availability time of 8760 hours, the total unavailability per EDG is about 88 hours. Nearly a 10% reduction in unavailability would be realized if one shift (8 hours) of down time per year was avoided. Draft NEI 99-02 (Reference C-3) reports the probability of an EDG failure to start on demand is 1.1×10^{-2} . This translates into about one failure per plant every 3 years, assuming the generators are started monthly and the average BWR has 2.5 diesels. Extending this to one failure per 3.3 years results in a 10% reduction of the failure probability.

The basic events that are assumed to be affected by the changes are:

- EDG Fails to Start
- EDG Fails to Run
- EDG Unavailability
- EDG Common Cause

Rather than specifying an impact on the parameter changes and re-quantifying the model, the risk impact was evaluated examining a reasonable range of improvements of the affected parameters. The range chosen was from a 5% reduction to a 15% reduction. Figure C.5-1 shows the effect of varying EDG reliability and availability parameters for the BWR 4. The results are fairly linear in the range of improvement expected. Similar results would be obtained for the other configurations.

The following table presents the CDF offsets for eight configurations with a 10% EDG reliability and availability improvement.

Configuration	CDF Offset Assuming a 10% Reduction in EDG Unavailability and Failure Rates
BWR 3/4 Base	4.48×10^{-7}
BWR 3/4 with AC Independent LP Injection	3.48×10^{-7}
BWR 3/4 with Independent AC Power Source	5.20×10^{-8}
BWR 5/6 Base	4.72×10^{-7}
BWR 5/6 with AC Independent LP Injection	3.37×10^{-7}
BWR 5/6 with Independent AC Power Source	5.40×10^{-8}
BWR 3/4 with LPCI Loop-Select and AC Independent LP Injection	3.41×10^{-7}
BWR 3/4 with LPCI Loop-Select and Independent AC Power Source	4.90×10^{-8}

Plants that rely more on their EDGs (i.e. those plants with a less reliable local grid) would benefit more from these changes. Plants that have implemented a backup to their onsite AC power sources do not benefit as much from this particular change.

LERF quantification was performed in combination with removing the anticipatory start.

C.5.5 Start EDGs Only When Needed

It is similarly difficult to predict the reduction of the operator action failure rates. Once again, though, a moderate decrease of 10% is expected if the proposed changes are made. This only applies to actions in the model that share dependence with the actions to secure a diesel generator that has spuriously started. These are defined as those actions taken outside the control room, that need to happen within one hour of the initiating event.

The operator actions in the generic model that are assumed to be affected are:

- Failure to locally align control panels and MCCs
- Failure to recover from electrical bus testing following the transient
- Failure to operate breakers locally & manually
- Failure to bypass failed instrument air components
- Failure to align instrument air to pneumatic equipment located in the drywell
- Failure to manually operate containment vent valves
- Failure to recover the PCS within 4 hours
- Failure to align service water injection

The following table presents the CDF offsets for eight configurations with a 10% improvement in the operator error rates for the actions listed above.

Configuration	CDF Offset Assuming a 10% Reduction in Human Error Probabilities
BWR 3/4 Base	3.09×10^{-7}
BWR 3/4 with AC Independent LP Injection	4.00×10^{-7}
BWR 3/4 with Independent AC Power Source	2.27×10^{-7}
BWR 5/6 Base	2.13×10^{-7}
BWR 5/6 with AC Independent LP Injection	3.03×10^{-7}
BWR 5/6 with Independent AC Power Source	1.32×10^{-7}
BWR 3/4 with LPCI Loop-Select and AC Independent LP Injection	3.10×10^{-7}
BWR 3/4 with LPCI Loop-Select and Independent AC Power Source	2.22×10^{-7}

LERF quantification was performed in combination with changing practices that improve diesel generator reliability and availability.

C.5.6 Combinations of LBLOCA/LOOP Changes

It is expected that plants that implement the changes in this report will select one or more of the changes. Therefore, the combinations of changes were evaluated to get an overall impact. Table C.5-1 shows the offsets from combining changes for the BWR 3/4 model; Table C.5-2 shows the offsets for the BWR 5/6; and Table C.5-3 shows the offsets for the BWR 4 with LPCI Loop-Select logic. As can be seen in the tables, combining the changes provides a greater offset.

C.6 NOT USED

Section C.6, which addressed the plant-to-plant variability in the original LTR, has been deleted in this revision since each licensee will be completing his or her own plant-specific risk assessment of the plant modifications using their own PRA.

C.7 CONCLUSIONS

This example analysis demonstrates that a generic BWR risk analysis can provide the necessary insights to justify changes to plant configurations under the Option 3 and Regulatory Guide 1.174 guidelines.

All of the changes evaluated in this appendix result in a CDF change that is either a risk benefit, or is negligible. Therefore, when these changes are combined with the assumption that all LBLOCA/LOOP events lead directly to core damage (Appendix B demonstrates that this assumption is very conservative), it can be clearly demonstrated that the CDF and LERF increases are well within the Regulatory Guide 1.174 guidelines.

The most beneficial of the changes, in terms of CDF and LERF, are those that affect the availability and reliability of the EDGs.

Even though the generic analysis demonstrates that the CDF and LERF risk increases are within acceptable limits, each licensee will perform a plant-specific risk assessment per the process outlined in Section 4.0 of the LTR, and submit it as part of his exemption request submittal.

C.8 REFERENCES

1. NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995", (INEEL/EXT-98-00401), February 1999.
2. NEI 99-02, "Mitigating Systems Performance Index," Draft 0, September 3, 2002.
3. Nuclear Energy Institute, "Regulatory Assessment Performance Indicator Guidelines", Proposed Revision to NEI-99-02, 8/13/2002.

Table C.3-1 Base Model Success Criteria

Function	Transient	Transient with SORV	Loss of Offsite Power	Loss of Service Water ¹	Large LOCA
High-Pressure Injection	1 Feedwater RCIC HPCI	1 Feedwater RCIC HPCI	RCIC HPCI	n/a	n/a
Low-Pressure Injection	1 LPCS Loop 1 LPCI Pump 1 Condensate Pump 1 RHR Service Water Pump 1 Firewater Pump ³	1 LPCS Loop 1 LPCI Pump 1 Condensate Pump 1 RHR Service Water Pump 1 Firewater Pump ³	1 LPCS Loop 1 LPCI Pump 1 RHR Service Water 1 Firewater Pump ³	n/a	1 LPCS Loop 2 LPCI Pumps
Depressurization	Main Steam 1 SRV	Main Steam 1 SRV RCIC HPCI	1 SRV	1 SRV	n/a
Containment Heat Removal	Main Steam 1 SPC 1 SDC Vent	Main Steam 1 SPC 1 SDC Vent	1 SPC 1 SDC Vent	Vent	1 SPC 1 Containment Spray Vent
Long-Term Core Cooling	Main Steam + 1 Condensate 1 SDC 1 SPC + RCIC 1 SPC + HPCI 1 SPC + 1 LPCS 1 SPC + 1 LPCI Vent + 1 Condensate Vent + 1 RHR Service Water Vent + 2 CRD Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	Main Steam + 1 Condensate 1 SDC 1 SPC + 1 LPCS 1 SPC + 1 LPCI Vent + 1 Condensate Vent + 1 RHR Service Water Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	1 SDC 1 SPC + RCIC 1 SPC + HPCI 1 SPC + 1 LPCS 1 SPC + 1 LPCI Vent + 1 RHR Service Water Vent + 2 CRD Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ¹	1 SPC + 1 LPCS 1 SPC + 1 LPCI 1 Cont Spray + 1 LPCS 1 Cont Spray + 1 LPCI Vent + 1 Condensate Vent + 1 RHR Service Water Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater ³
Reactivity Control ²	n/a	n/a	n/a	n/a	n/a
Pressure Relief	Main Steam 1 SRV Opens	n/a	1 SRV Opens	1 SRV Opens	n/a
Pressure Suppression	n/a	SRV Tailpipe Intact	SRV Tailpipe Intact if SORV	SRV Tailpipe Intact if SORV	7 of 8 Vacuum Breakers Seat

Table C.3-1 Base Model Success Criteria (continued)

Function	Medium LOCA	Small LOCA	ATWS (Transient)	ATWS (Loss of Offsite Power)	ATWS (Large or Medium LOCA)
High-Pressure Injection	HPCI	1 Feedwater RCIC HPCI	1 Feedwater HPCI	HPCI	n/a
Low-Pressure Injection	1 LPCS 1 LPCI	1 LPCS 1 LPCI	1 LPCS 1 LPCI	1 LPCS 1 LPCI	n/a
Depressurization	HPCI 1 SRV	Main Steam RCIC HPCI 1 SRV	Main Steam 1 SRV	1 SRV	n/a
Containment Heat Removal	1 SPC 1 Containment Spray Vent	1 SPC 1 Containment Spray Vent	1 SLC + 1 SPC 1 SLC + Vent	1 SLC + 1 SPC 1 SLC + Vent	n/a
Long-Term Core Cooling	1 SPC + 1 LPCS 1 SPC + 1 LPCI 1 Cont Spray + 1 LPCS 1 Cont Spray + 1 LPCI Vent + 1 Condensate Vent + 1 Service Water Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	Main Steam + 1 Condensate 1 SPC + RCIC 1 SPC + HPCI 1 SPC + 1 LPCS 1 SPC + 1 LPCI 1 Cont Spray + RCIC 1 Cont Spray + HPCI 1 Cont Spray + 1 LPCS 1 Cont Spray + 1 LPCI Vent + 1 Service Water Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	Main Steam + 1 Condensate Main Steam + HPCI 1 SPC + HPCI 1 SPC + 1 LPCS 1 SPC + 1 LPCI Vent + 1 Service Water Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	1 SPC + HPCI 1 SPC + 1 LPCS 1 SPC + 1 LPCI Vent + 1 Service Water Vent + 1 LPCS from CST Vent + 1 LPCI from CST Vent + 1 Firewater Pump ³	n/a
Reactivity Control ²	n/a	n/a	RPS ARI Manual scram Recirc Pump Trip + Level Control + ADS Inhibit AND 1 SLC Main Steam Available 2 SLC Main Steam Unavailable	RPS ARI Manual scram Recirc Pump Trip + Level Control + ADS Inhibit AND 1 SLC Main Steam Available 2 SLC Main Steam Unavailable	RPS ARI Manual scram
Pressure Relief	n/a	1 SRV Opens	1 SRV Opens	1 SRV Opens	n/a
Pressure Suppression	7 of 8 Vacuum Breakers Seat	SRV Tailpipe Intact	n/a	n/a	n/a

Table C.3-1 Base Model Success Criteria (continued)

Notes for Success Criteria Table:

- 1) Short-term injection systems were not asked in the Loss of Service Water event tree. These failures are assumed to generate the same sequences as short-term injection failures in the Transient event tree. Because the frequency of a Loss of Service Water event is much less than that of a Transient, the results of the model are virtually unchanged by making this simplification.
- 2) Reactivity Control is addressed explicitly in the ATWS event trees. It is simply shown for illustrative purposes on the other event trees.
- 3) Firewater is not available in many plant configurations. It is only included in the cases in which an AC Independent Low-pressure injection system is indicated.

Table C.3-2 Initiating Event Frequencies and Distributions

Initiator	Mean	95th	Lognormal Error Factor
Large LOCA	3.00E-05	1.00E-04	6.1
Medium LOCA	4.00E-05	1.00E-04	3.2
Small LOCA	5.00E-04	1.00E-03	2.3
Leak	6.20E-03	1.20E-02	2.2
Stuck/Inadvertent Open Relief Valve	4.60E-02	7.10E-02	1.6
Loss of Offsite Power	4.60E-02	1.10E-01	3.0
Main Steam Isolation	2.90E-01	3.90E-01	1.4
Loss of Feedwater	8.50E-02	2.50E-01	4.4
Transient with Condenser Available	1.50E+00	2.50E+00	1.8
Loss of a Single DC Bus	2.10E-03	5.40E-03	3.4
Loss of a Single AC Division	1.90E-02	2.80E-02	1.5
Loss of Instrument Power	4.80E-03	9.70E-03	2.3
Loss of Service Water (any system)	9.70E-04	2.50E-03	3.4
Loss of Instrument Air	2.90E-02	5.50E-02	2.1

Table C.3-3 Quantification Results

Plant Type	Configuration	Change	CDF	LERF
BWR 4	No AC Independent Injection No Diverse Onsite AC Power		9.45×10^{-6}	7.62×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	9.45×10^{-6}	7.62×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	9.44×10^{-6}	7.63×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	9.41×10^{-6}	7.62×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	9.40×10^{-6}	7.62×10^{-8}
	AC Independent Injection No Diverse Onsite AC Power		6.83×10^{-6}	4.45×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	6.81×10^{-6}	4.46×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	6.80×10^{-6}	4.45×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	6.83×10^{-6}	4.46×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	6.80×10^{-6}	4.46×10^{-8}
	Diverse Onsite AC Power		4.63×10^{-6}	6.51×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	4.63×10^{-6}	6.51×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	4.62×10^{-6}	6.51×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	4.59×10^{-6}	6.51×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	4.59×10^{-6}	6.51×10^{-8}

Table C.3-3 Quantification Results (continued)

Plant Type	Configuration	Change	CDF	LERF
BWR 6	No AC Independent Injection No Diverse Onsite AC Power		7.64×10^{-6}	6.32×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	7.63×10^{-6}	6.32×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	7.63×10^{-6}	6.32×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	7.61×10^{-6}	6.32×10^{-8}
		1 LPCS and 1 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	7.60×10^{-6}	6.33×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	7.60×10^{-6}	6.32×10^{-8}
	AC Independent Injection No Diverse Onsite AC Power		4.86×10^{-6}	3.73×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	4.83×10^{-6}	3.73×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	4.83×10^{-6}	3.73×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	4.86×10^{-6}	3.73×10^{-8}
		1 LPCS and 1 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	4.83×10^{-6}	3.73×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	4.83×10^{-6}	3.73×10^{-8}

Table C.3-3 Quantification Results (continued)

Plant Type	Configuration	Change	CDF	LERF
BWR 6	Diverse Onsite AC Power		2.63×10^{-6}	5.29×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	2.63×10^{-6}	5.29×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	2.63×10^{-6}	5.29×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	2.60×10^{-6}	5.29×10^{-8}
		1 LPCS and 1 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	2.59×10^{-6}	5.29×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	2.59×10^{-6}	5.29×10^{-8}

Table C.3-3 Quantification Results (continued)

Plant Type	Configuration	Change	CDF	LERF
BWR 4 with LPCI Loop-Select	No AC Independent Injection No Diverse Onsite AC Power	[No plants in this category]		
BWR 4 with LPCI Loop-Select	AC Independent Injection No Diverse Onsite AC Power		6.71×10^{-6}	4.45×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	6.69×10^{-6}	4.45×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	6.69×10^{-6}	4.45×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	6.71×10^{-6}	4.45×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	6.69×10^{-6}	4.45×10^{-8}
		Eliminate Loop Select	6.71×10^{-6}	4.45×10^{-8}
		Eliminate Loop Select and LPCS Does Not Start Automatically Following LOOP	6.69×10^{-6}	4.46×10^{-8}
		Eliminate Loop Select and 2 LPCI Pumps Do Not Start Automatically Following LOOP	6.69×10^{-6}	4.45×10^{-8}
		Eliminate Loop Select and 1 Loop of RHR Automatically Starts in SPC Mode	6.71×10^{-6}	4.46×10^{-8}
		Eliminate Loop Select and 2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	6.69×10^{-6}	4.46×10^{-8}

Table C.3-3 Quantification Results (continued)

Plant Type	Configuration	Change	CDF	LERF
BWR 4 with LPCI Loop-Select	Diverse Onsite AC Power		4.55×10^{-6}	6.51×10^{-8}
		LPCS Does Not Start Automatically Following LOOP	4.55×10^{-6}	6.52×10^{-8}
		2 LPCI Pumps Do Not Start Automatically Following LOOP	4.55×10^{-6}	6.51×10^{-8}
		1 Loop of RHR Automatically Starts in SPC Mode	4.52×10^{-6}	6.52×10^{-8}
		2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	5.51×10^{-6}	6.52×10^{-8}
		Eliminate Loop Select	4.55×10^{-6}	6.52×10^{-8}
		Eliminate Loop Select and LPCS Does Not Start Automatically Following LOOP	4.55×10^{-6}	6.52×10^{-8}
		Eliminate Loop Select and 2 LPCI Pumps Do Not Start Automatically Following LOOP	4.55×10^{-6}	6.52×10^{-8}
		Eliminate Loop Select and 1 Loop of RHR Automatically Starts in SPC Mode	4.52×10^{-6}	6.52×10^{-8}
		Eliminate Loop Select and 2 LPCI Pumps Do Not Start Automatically and 1 Loop of RHR Automatically Starts in SPC Mode	4.52×10^{-6}	6.52×10^{-8}

Table C.3-4 Plant Damage State Definitions

PDS	Conditional Probability of LERF	Description	Binning Rules
ATSLC	5.32×10^{-2}	Failure to scram accident with subsequent reactivity control. Inadequate coolant injection results in core damage in approximately an hour with the containment intact.	Transient, support, or LOCA initiator; scram failure; RPT successful; early or late SLC successful; level controlled to TAF; ADS inhibited; no RPV overfill; no RPV injection
ATWS	1.31×10^{-1}	Failure to scram accident with subsequent reactivity control failure.	A initiator; scram failure - or - Transient, support, or LOCA initiator; scram failure; RPT failure - or - Transient, support, or LOCA initiator; scram failure; RPT successful; early or late SLC successful; RPV level overfilled and boron diluted - or - Transient, support, or LOCA initiator; scram failure; RPT successful; early and late SLC failure - or - Transient, support, or LOCA initiator; scram failure; RPT successful; early or late SLC successful; level not controlled to TAF - or - Transient, support, or LOCA initiator; scram failure; RPT successful; early or late SLC successful; failure to inhibit ADS
DT-SBHP	3.94×10^{-4}	Station blackout with initial HPCI or RCIC injection. Battery depletion occurs in approximately 4 hours with core damage occurring at about 5 hours with the RPV at high-pressure and the containment intact.	LOSP; emergency AC fails; no SORV; HPCI or RCIC success
DT-SBLP	1.84×10^{-4}	Station blackout with a stuck open relief valve (or the operators depressurize the plant prior to core damage) and initial HPCI or RCIC injection. Battery depletion occurs in approximately 4 hours with core damage occurring at about 5 hours with the RPV at low pressure and the containment intact.	LOSP; emergency AC fails; SORV; HPCI or RCIC success - or - T3C initiator; coincident LOSP; emergency AC fails; HPCI or RCIC success - or - LOSP; emergency AC fails; SORV; HPCI or RCIC success; depressurization before core damage
LOCA	9.06×10^{-3}	Loss of coolant accident with inadequate coolant injection. Core damage occurs in approximately an hour with the containment intact.	A, S1, or S2 initiator, or S3 w/leak unisolated; scram successful; no injection

Table C.3-4 Plant Damage State Definitions (continued)

PDS	Conditional Probability of LERF	Description	Binning Rules
PSS	6.21×10^{-1}	LOCA, or SORV, with failure of the pressure suppression system. Containment fails rapidly, failing injection systems due to harsh environmental effects. Core damage occurs in about an hour and a half with the RPV at low pressure.	Transient initiator; SORV; PSS failure - or - LOCA initiator; PSS failure
ST-SBHP	8.35×10^{-2}	Station blackout with no injection. Core damage occurs in approximately an hour with the RPV at high pressure and the containment intact.	LOSP; emergency AC fails; no SORV; no HP injection
ST-SBLP	2.77×10^{-2}	Station blackout with a stuck open relief valve and no injection. Core damage occurs in approximately an hour with the RPV at low pressure and the containment intact.	LOSP; emergency AC fails; SORV; no HP injection - or - T3C initiator; coincident LOSP; emergency AC fails; no HP injection
TPUV	0.0	Transient with a stuck open relief valve and loss of all coolant injection. Core damage occurs in approximately an hour with the RPV at low pressure and the containment intact.	Transient initiator; scram successful; SORV; no HP injection; no LP injection - or - T3C initiator; scram successful; no HP injection; no LP injection
TPUX	2.00×10^{-6}	Transient with a stuck open relief valve, loss of coolant injection and failure to depressurize the RPV to allow low-pressure injection. Core damage occurs in approximately an hour with the RPV still at high pressure and the containment intact.	Transient or support initiator, or S3 w/leak isolated; scram successful; SORV; all HP injection fails; timely depressurization fails
TQUV	3.47×10^{-2}	Transient with loss of all coolant injection. Core damage occurs in approximately an hour with the RPV at low pressure and the containment intact.	Transient or support initiator, or S3 w/leak isolated; scram successful; no SORV; all HP injection fails; timely depressurization successful; all LP injection fails
TQUX	0.0	Transient with loss of coolant injection and failure to depressurize the RPV to allow low-pressure injection. Core damage occurs in approximately an hour with the RPV at high pressure and the containment intact.	Transient or support initiator, or S3 w/leak isolated; scram successful; no SORV; all HP injection fails; timely depressurization fails

Table C.3-4 Plant Damage State Definitions (continued)

PDS	Conditional Probability of LERF	Description	Binning Rules
TWDT	0.0	Transient with initial ECCS injection but loss of all containment heat removal methods. Containment heat-up causes loss of injection sources due to loss of NPSH at about 4 hours. Core damage occurs at approximately 12.5 hours with containment intact.	<p>Transient, support, or LOCA initiator; scram successful; initial HPCI or RCIC injection; SPC failure; depressurization failure</p> <p>- or -</p> <p>Transient, support, or LOCA initiator; scram successful; initial HPCI or RCIC injection; SPC failure; depressurization successful; SDC failure; LPCI or LPCS successful; containment vent failure</p> <p>- or -</p> <p>Transient, support, or LOCA initiator; scram successful; no initial HP injection; timely depressurization successful; initial LPCI or LPCS injection; SPC failure; SDC failure; containment vent failure</p> <p>- or -</p> <p>Transient, support, or LOCA initiator; scram successful; initial HPCI or RCIC injection; SPC failure; depressurization successful; SDC failure; all LP injection failure</p> <p>- or -</p> <p>Transient w/SORV initiator; scram successful; initial HPCI or RCIC injection; SPC failure; SDC failure; LP injection failure due to suppression pool heat up</p>
TPWLT	0.0	Transient with SORV (or LOCA initiator), with initial successful injection but loss of all containment heat removal methods. Alignment of external low-pressure injection sources continues core cooling until containment failure at approximately 27 hrs.	<p>Transient w/SORV, or LOCA initiator; scram successful; initial HPCI or RCIC injection; SPC failure; depressurization successful; SDC failure; vent successful; all LP injection failure</p>

Table C.3-4 Plant Damage State Definitions (continued)

PDS	Conditional Probability of LERF	Description	Binning Rules
TWLT	0.0	Transient w/injection but loss of containment heat removal. Alignment of ext. LP injection delays core damage until SRVs re-close due to high containment pressure, failing injection. Core damage in >24 hrs with containment intact but at high pressure.	<p>Transient or support (except TTEC or TREC) initiator, or S3 w/leak isolated; scram successful; no SORV; SPC failure; depressurization failure</p> <p>- or -</p> <p>Transient or support (except TTEC or TREC) initiator, or S3 w/leak isolated; scram successful; no SORV; SPC failure; depressurization successful; SDC failure; containment vent failure</p> <p>- or -</p> <p>Transient, support, or LOCA initiator; scram successful; no SORV; initial HPCI or RCIC injection; SPC failure; depressurization successful; SDC failure; condensate or cross-tie injection successful; containment vent failure</p>

Table C.5-1 Combined CDF Offsets for BWR 3/4 Plant Configurations

Configuration	ECCS Change*	ECCS Offset	EDG Reliability Offset**	HRA Offset***	Both EDG and HRA Offset	LERF Offset (ECCS Change Only)	LERF Offset (All Changes)
No AC Independent Injection No Diverse Onsite AC Power			4.48×10^{-7}	3.09×10^{-7}	7.51×10^{-7}		1×10^{-9}
	LPCS	1.2×10^{-8}	4.58×10^{-7}	3.20×10^{-7}	7.61×10^{-7}	ϵ	1×10^{-9}
	LPCI	1.4×10^{-8}	4.59×10^{-7}	3.21×10^{-7}	7.62×10^{-7}	ϵ	1×10^{-9}
	RHR in SPC	4.1×10^{-8}	4.87×10^{-7}	3.45×10^{-7}	7.86×10^{-7}	ϵ	1×10^{-9}
	LPCI and RHR in SPC	5.3×10^{-8}	4.98×10^{-7}	3.57×10^{-7}	7.97×10^{-7}	ϵ	1×10^{-9}
AC Independent Injection No Diverse Onsite AC Power			3.48×10^{-7}	4.00×10^{-7}	7.37×10^{-7}	ϵ	ϵ
	LPCS	3.0×10^{-8}	3.75×10^{-7}	4.28×10^{-7}	7.64×10^{-7}	ϵ	ϵ
	LPCI	3.0×10^{-8}	3.76×10^{-7}	4.28×10^{-7}	7.64×10^{-7}	ϵ	ϵ
	RHR in SPC	6.0×10^{-8}	3.52×10^{-7}	4.03×10^{-7}	7.40×10^{-7}	ϵ	ϵ
	LPCI and RHR in SPC	3.3×10^{-8}	3.79×10^{-7}	4.30×10^{-7}	7.66×10^{-7}	ϵ	ϵ
Diverse Onsite AC Power			5.2×10^{-8}	2.27×10^{-7}	2.80×10^{-7}	ϵ	ϵ
	LPCS	2×10^{-9}	5.5×10^{-8}	2.30×10^{-7}	2.82×10^{-7}	ϵ	ϵ
	LPCI	3×10^{-9}	5.6×10^{-8}	2.31×10^{-7}	2.84×10^{-7}	ϵ	ϵ
	RHR in SPC	3.6×10^{-8}	8.8×10^{-8}	2.63×10^{-7}	3.15×10^{-7}	ϵ	ϵ
	LPCI and RHR in SPC	3.9×10^{-8}	9.2×10^{-8}	2.67×10^{-7}	3.19×10^{-7}	ϵ	ϵ

- * LPCS - LPCS not started automatically following LOOP
 LPCI - 2 of 4 LPCI pumps not started automatically following LOOP
 RHR in SPC - One Loop of RHR started automatically in SPC mode
- ** 10% reduction in failure rates and unavailability applied
- *** 10% reduction in selected human error rates applied

Table C.5-2 Combined CDF Offsets for BWR 5/6 Plant Configurations

Configuration	ECCS Change*	ECCS Offset	EDG Reliability Offset**	HRA Offset***	Both EDG and HRA Offset	LERF Offset (ECCS Change Only)	LERF Offset (All Changes)
No AC Independent Injection No Diverse Onsite AC Power			4.72×10^{-7}	2.13×10^{-7}	6.79×10^{-7}		1×10^{-9}
	LPCS	1.3×10^{-8}	4.83×10^{-7}	2.24×10^{-7}	6.90×10^{-7}	ϵ	1×10^{-9}
	LPCI	1.3×10^{-8}	4.83×10^{-7}	2.25×10^{-7}	6.91×10^{-7}	ϵ	1×10^{-9}
	RHR in SPC	3.7×10^{-8}	5.07×10^{-7}	2.44×10^{-7}	7.11×10^{-7}	ϵ	1×10^{-9}
	LPCS and RHR in SPC	4.8×10^{-8}	5.18×10^{-7}	2.56×10^{-7}	7.21×10^{-7}	ϵ	1×10^{-9}
	LPCI and RHR in SPC	4.9×10^{-8}	5.19×10^{-7}	2.56×10^{-7}	7.22×10^{-7}	ϵ	1×10^{-9}
AC Independent Injection No Diverse Onsite AC Power			3.37×10^{-7}	3.03×10^{-7}	6.41×10^{-7}	ϵ	ϵ
	LPCS	3.3×10^{-8}	3.70×10^{-7}	3.36×10^{-7}	6.74×10^{-7}	ϵ	ϵ
	LPCI	3.3×10^{-8}	3.71×10^{-7}	3.37×10^{-7}	6.74×10^{-7}	ϵ	ϵ
	RHR in SPC	2×10^{-9}	3.39×10^{-7}	3.05×10^{-7}	6.43×10^{-7}	ϵ	ϵ
	LPCS and RHR in SPC	3.2×10^{-8}	3.70×10^{-7}	3.36×10^{-7}	6.73×10^{-7}	ϵ	ϵ
	LPCI and RHR in SPC	3.3×10^{-8}	3.70×10^{-7}	3.36×10^{-7}	6.74×10^{-7}	ϵ	ϵ
Diverse Onsite AC Power			5.3×10^{-8}	1.32×10^{-7}	1.86×10^{-7}	ϵ	ϵ
	LPCS	3×10^{-9}	5.7×10^{-8}	1.35×10^{-7}	1.89×10^{-7}	ϵ	ϵ
	LPCI	4×10^{-9}	5.8×10^{-8}	1.36×10^{-7}	1.90×10^{-7}	ϵ	ϵ
	RHR in SPC	3.5×10^{-8}	8.9×10^{-8}	1.67×10^{-7}	2.21×10^{-7}	ϵ	ϵ
	LPCS and RHR in SPC	3.9×10^{-8}	9.2×10^{-8}	1.70×10^{-7}	2.24×10^{-7}	ϵ	ϵ
	LPCI and RHR in SPC	3.9×10^{-8}	9.3×10^{-8}	1.71×10^{-7}	2.25×10^{-7}	ϵ	ϵ

- * LPCS - 1 LPCS and 1 LPCI not started automatically following LOOP
 LPCI - 2 LPCI pumps not started automatically following LOOP
 RHR in SPC - One Loop of RHR started automatically in SPC mode
- ** 10% reduction in failure rates and unavailability applied
- *** 10% reduction in selected human error rates applied

Table C.5-3 Combined CDF Offsets for BWR 3/4 with LPCI Loop-Select Plant Configurations

Configuration ^{****}	ECCS Change*	ECCS Offset	EDG Reliability Offset**	HRA Offset***	Both EDG and HRA Offset	LERF Offset (ECCS Change Only)	LERF Offset (All Changes)
AC Independent Injection No Diverse Onsite AC Power			3.41×10^{-7}	3.10×10^{-7}	6.51×10^{-7}	ε	ε
	LPCS	2.0×10^{-8}	3.61×10^{-7}	3.30×10^{-7}	6.71×10^{-7}	ε	ε
	LPCI	2.1×10^{-8}	3.62×10^{-7}	3.31×10^{-7}	6.72×10^{-7}	ε	ε
	RHR in SPC	3×10^{-9}	3.44×10^{-7}	3.13×10^{-7}	6.54×10^{-7}	ε	ε
	LPCI and RHR in SPC	2.1×10^{-8}	3.62×10^{-7}	3.31×10^{-7}	6.72×10^{-7}	ε	ε
	Loop Select	(1×10^{-9})	3.39×10^{-7}	3.07×10^{-7}	6.43×10^{-7}	ε	ε
	LPCS and Loop Select	1.7×10^{-8}	3.58×10^{-7}	3.27×10^{-7}	6.69×10^{-7}	ε	ε
	LPCI and Loop Select	1.8×10^{-8}	3.59×10^{-7}	3.28×10^{-7}	6.69×10^{-7}	ε	ε
	RHR in SPC and Loop Select	(2×10^{-8})	3.39×10^{-7}	3.08×10^{-7}	6.49×10^{-7}	ε	ε
	LPCI and RHR in SPC and Loop Select	1.6×10^{-8}	3.57×10^{-7}	3.26×10^{-7}	6.67×10^{-7}	ε	ε
Diverse Onsite AC Power			4.9×10^{-8}	2.22×10^{-7}	2.71×10^{-7}	ε	ε
	LPCS	2×10^{-9}	5.1×10^{-8}	2.24×10^{-7}	2.72×10^{-7}	ε	ε
	LPCI	3×10^{-9}	5.2×10^{-8}	2.25×10^{-7}	2.74×10^{-7}	ε	ε
	RHR in SPC	3.5×10^{-8}	8.4×10^{-8}	2.57×10^{-7}	3.06×10^{-7}	ε	ε
	LPCI and RHR in SPC	3.8×10^{-8}	8.7×10^{-8}	2.60×10^{-7}	3.09×10^{-7}	ε	ε
	Loop Select	(2×10^{-9})	4.7×10^{-8}	2.19×10^{-7}	2.68×10^{-7}	ε	ε
	LPCS and Loop Select	ε	4.8×10^{-8}	2.21×10^{-7}	2.70×10^{-7}	ε	ε
	LPCI and Loop Select	1×10^{-9}	5.0×10^{-8}	2.23×10^{-7}	2.71×10^{-7}	ε	ε
	RHR in SPC and Loop Select	3.0×10^{-8}	7.9×10^{-8}	2.52×10^{-7}	3.01×10^{-7}	ε	ε
	LPCI and RHR in SPC and Loop Select	3.3×10^{-8}	8.2×10^{-8}	2.55×10^{-7}	3.04×10^{-7}	ε	ε

**** No Loop-Select plants are in the base BWR 3/4 configuration

- * LPCS - LPCS not started automatically following LOOP
- LPCI - 2 of 4 LPCI pumps not started automatically following LOOP
- RHR in SPC - One Loop of RHR started automatically in SPC mode
- Loop Select - Eliminate LPCI Loop Select Logic

** 10% reduction in failure rates and unavailability applied

*** 10% reduction in selected human error rates applied

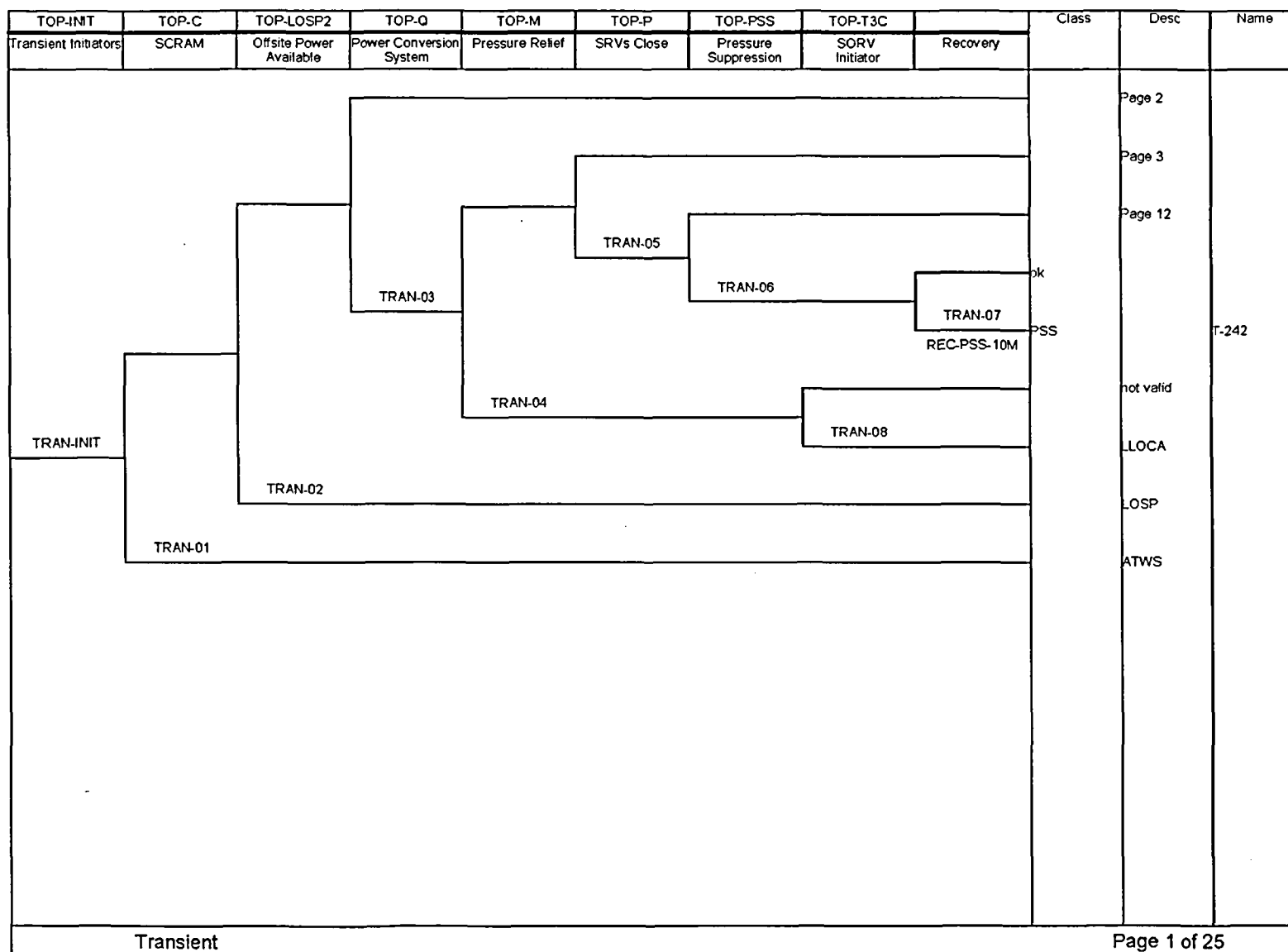


Figure C.3-1 Transient Event Tree

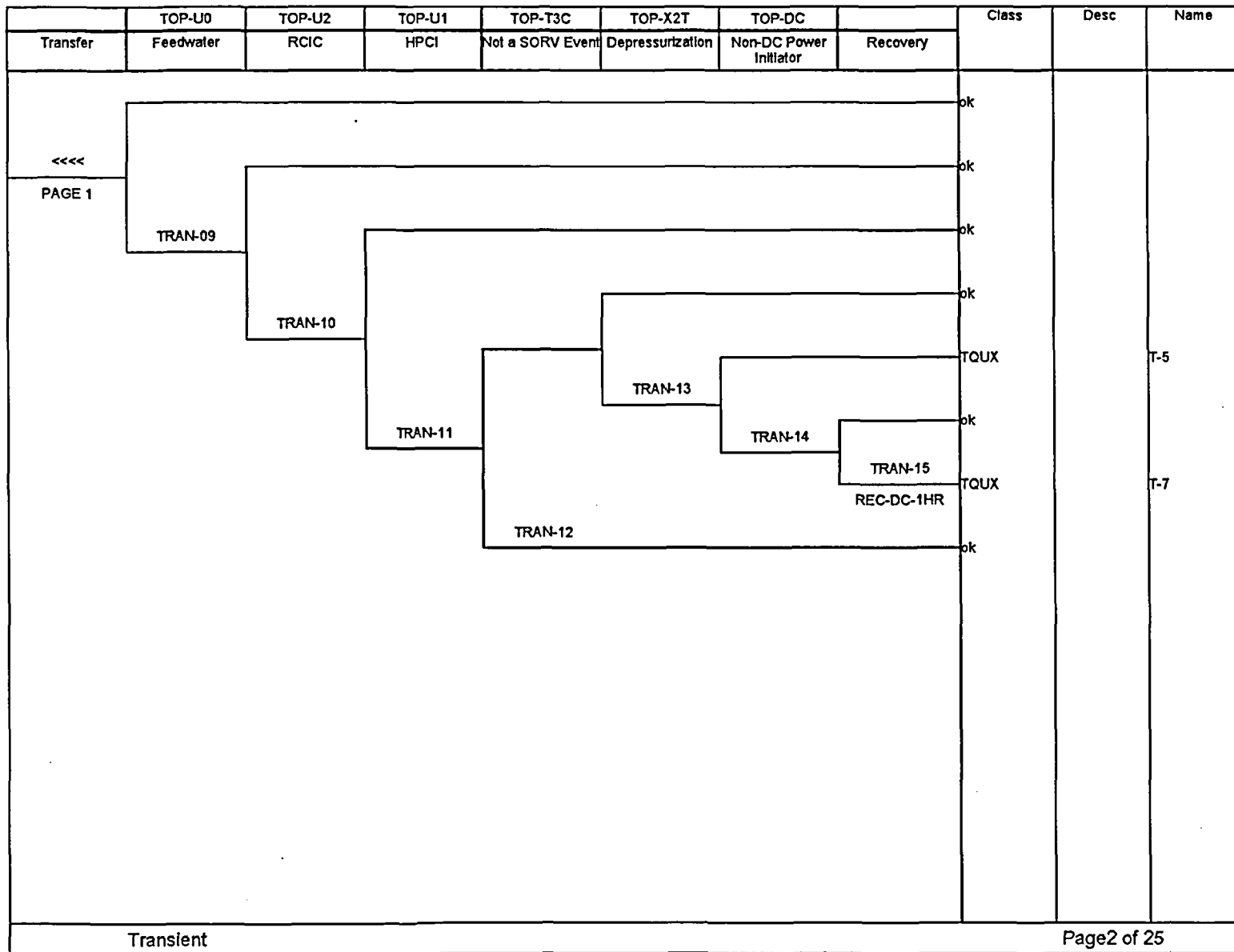


Figure C.3-1 Transient Event Tree (Continue)

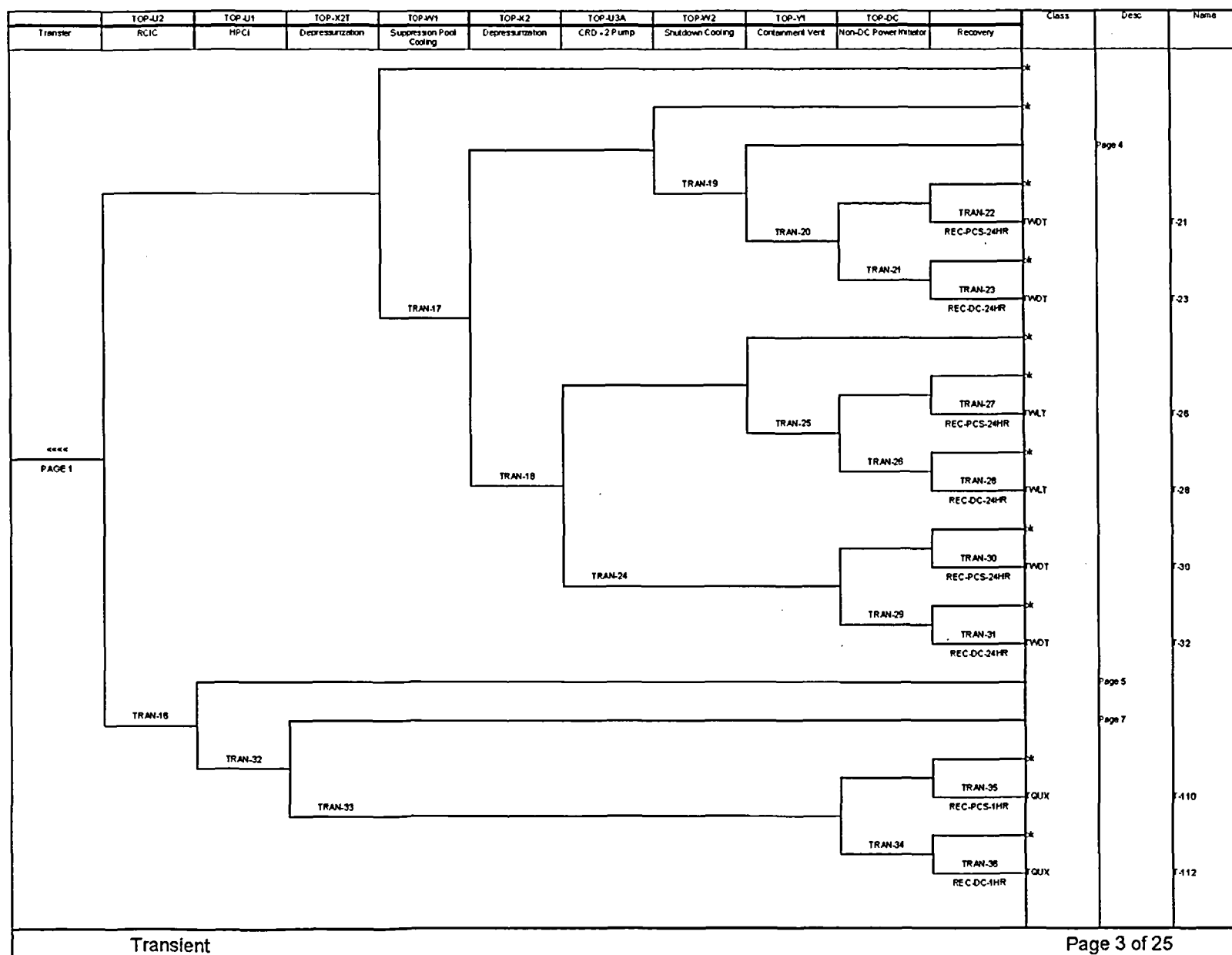


Figure C.3-1 Transient Event Tree (Continue)

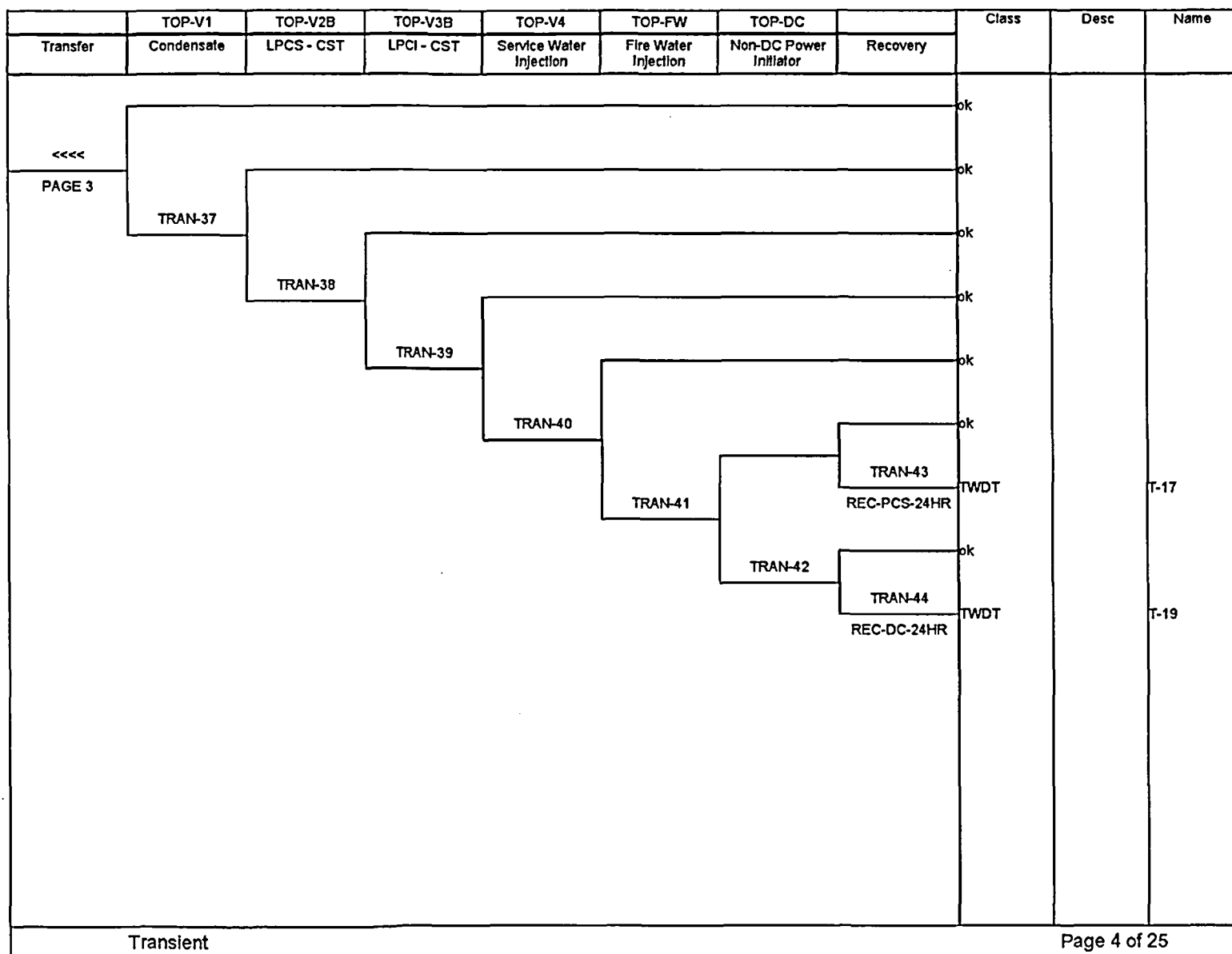


Figure C.3-1 Transient Event Tree (Continue)

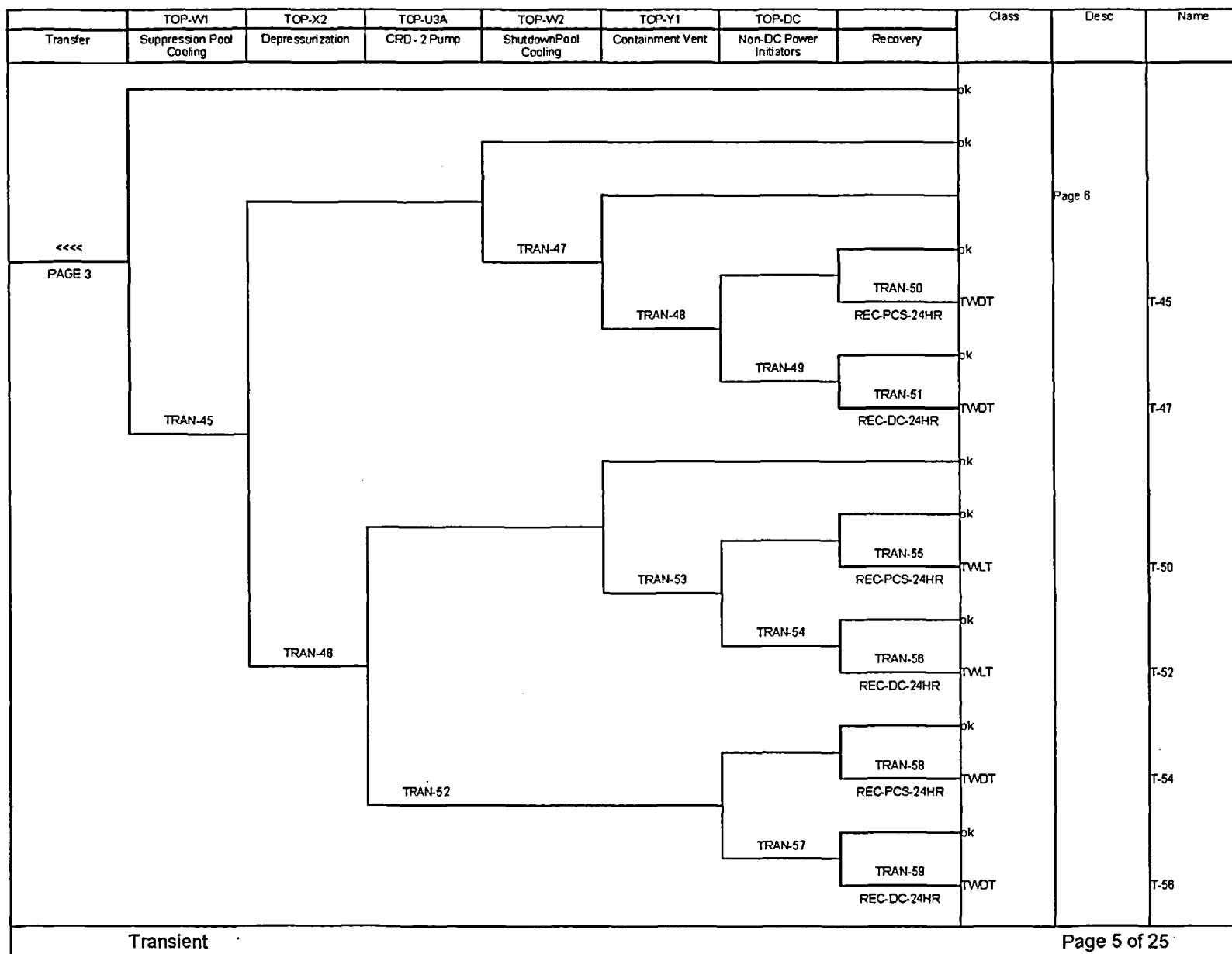


Figure C.3-1 Transient Event Tree (Continue)

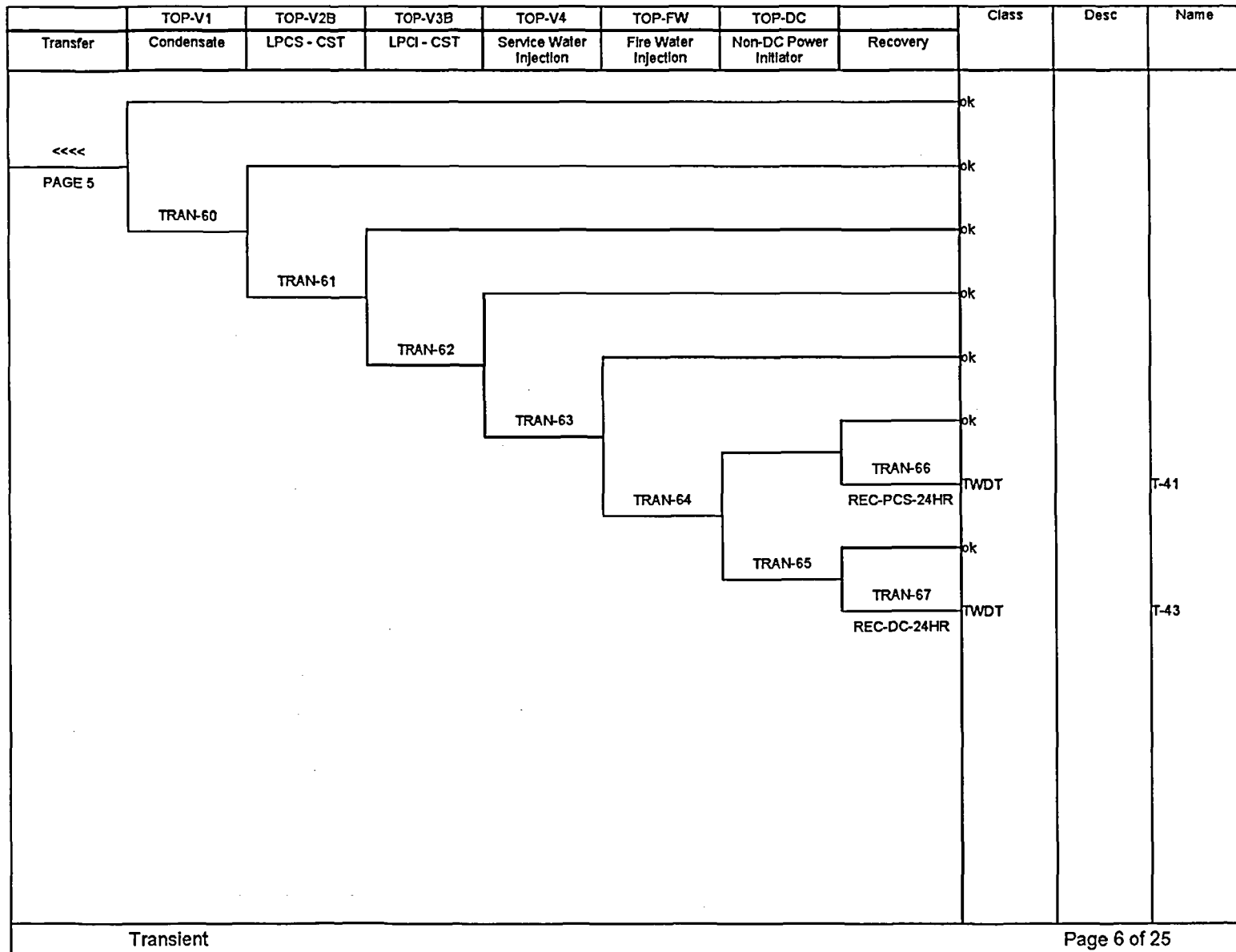


Figure C.3-1 Transient Event Tree (Continue)

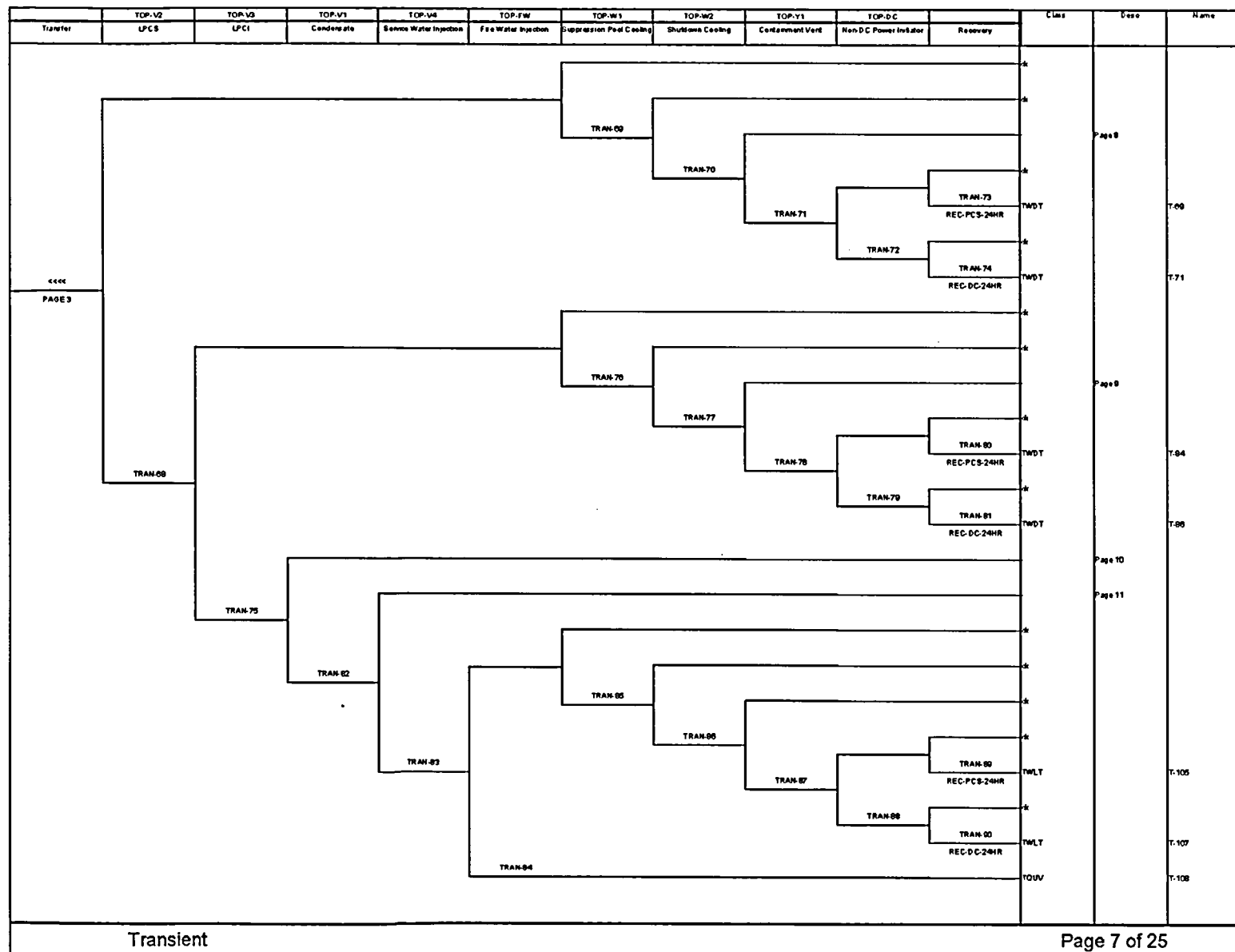


Figure C.3-1 Transient Event Tree (Continue)

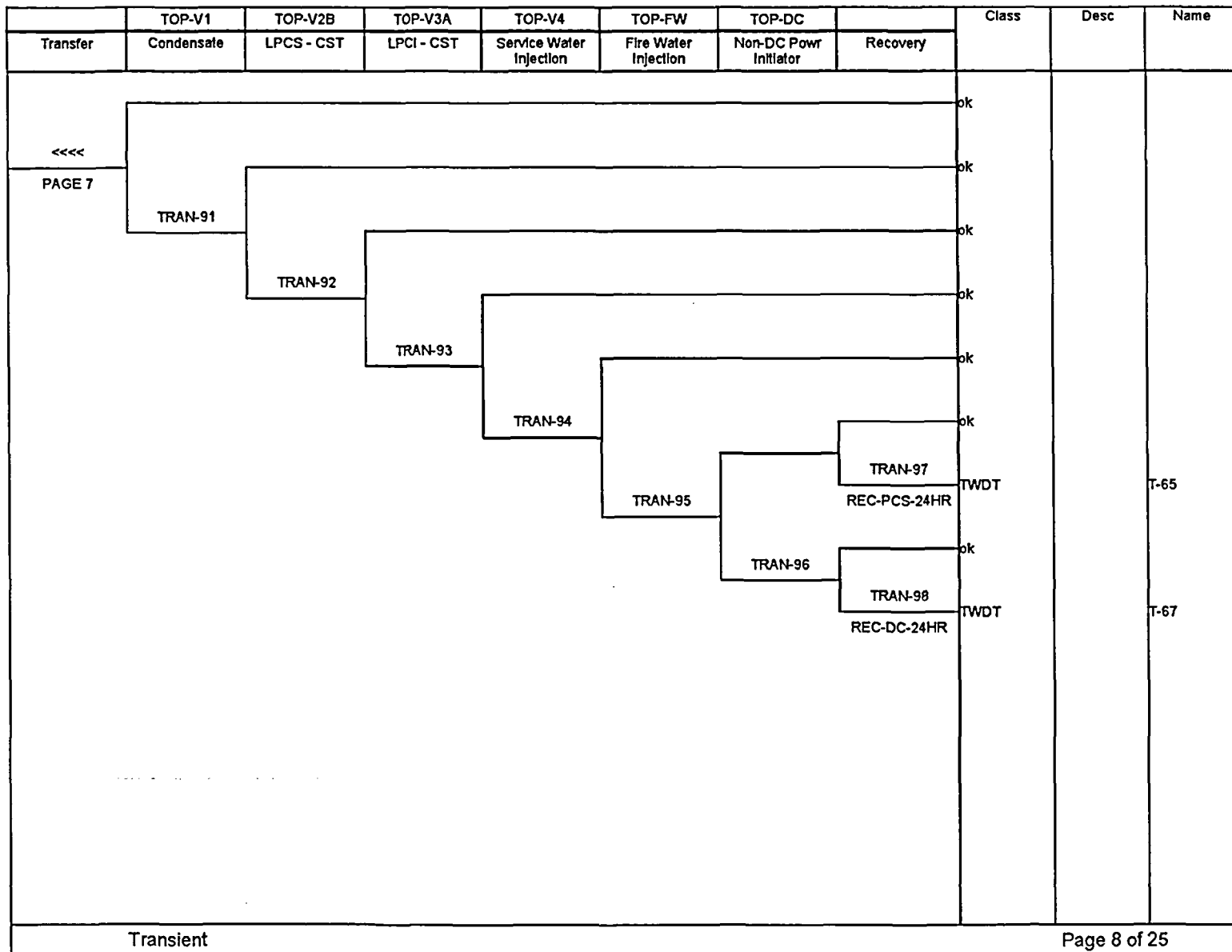


Figure C.3-1 Transient Event Tree (Continue)

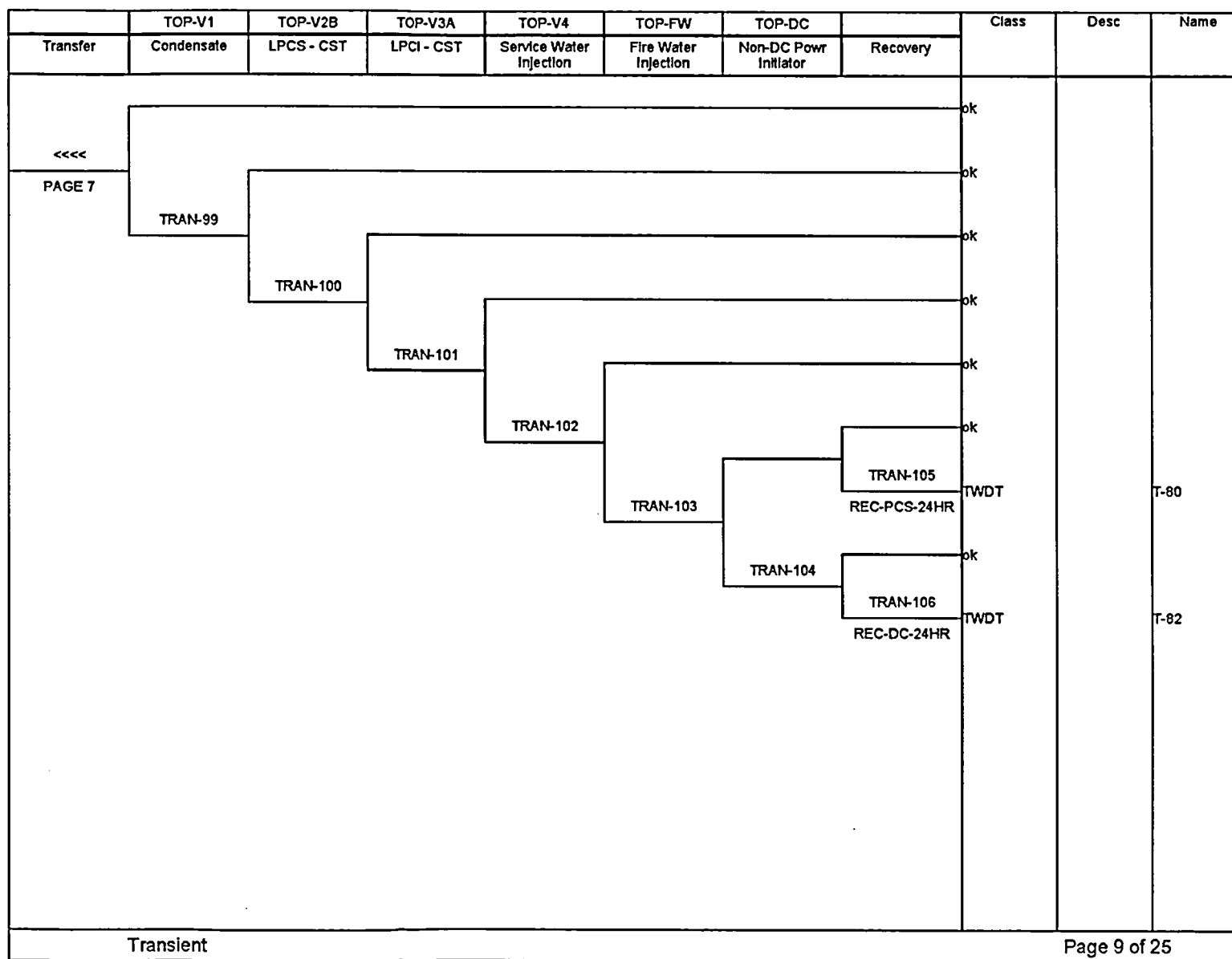


Figure C.3-1 Transient Event Tree (Continue)

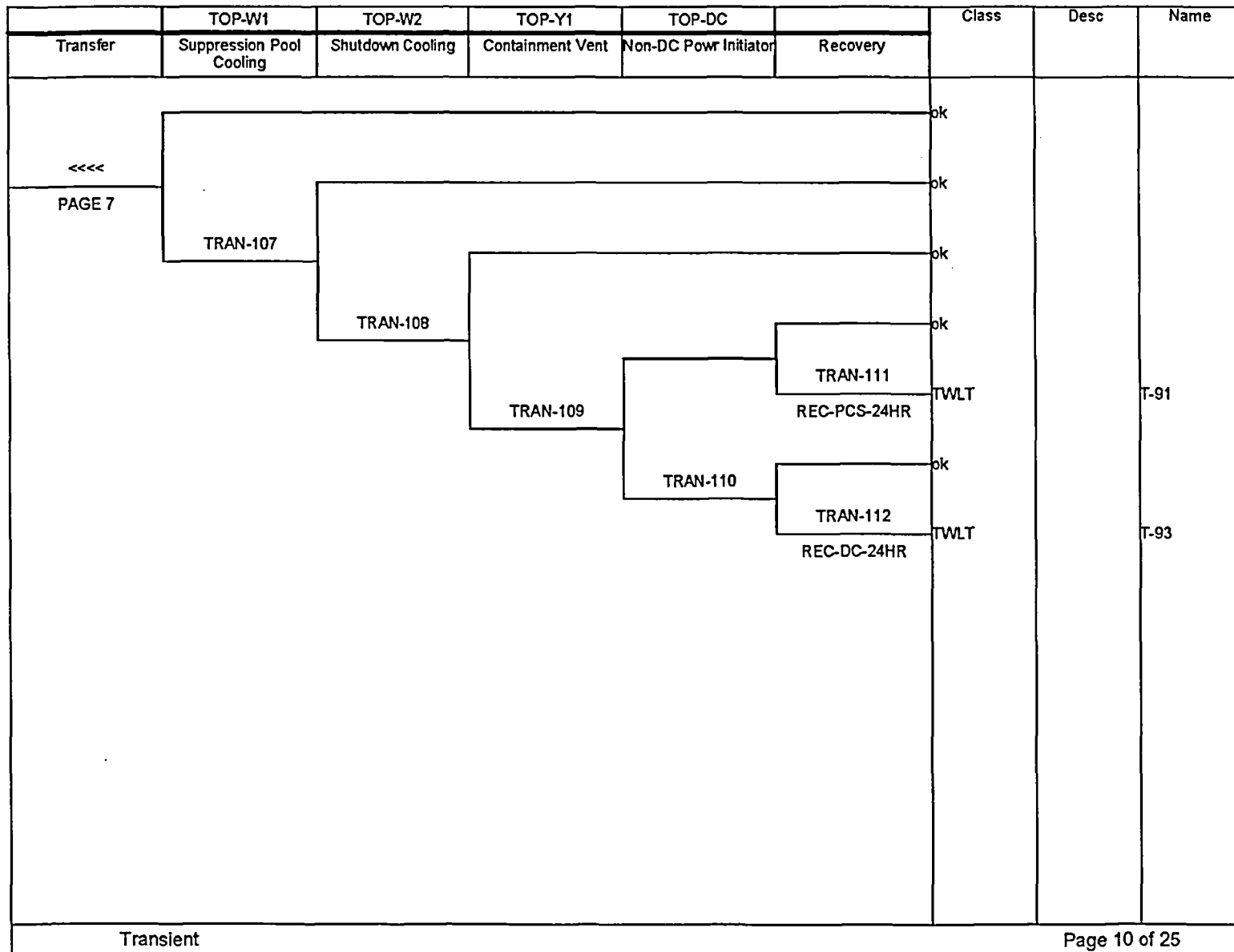


Figure C.3-1 Transient Event Tree (Continue)

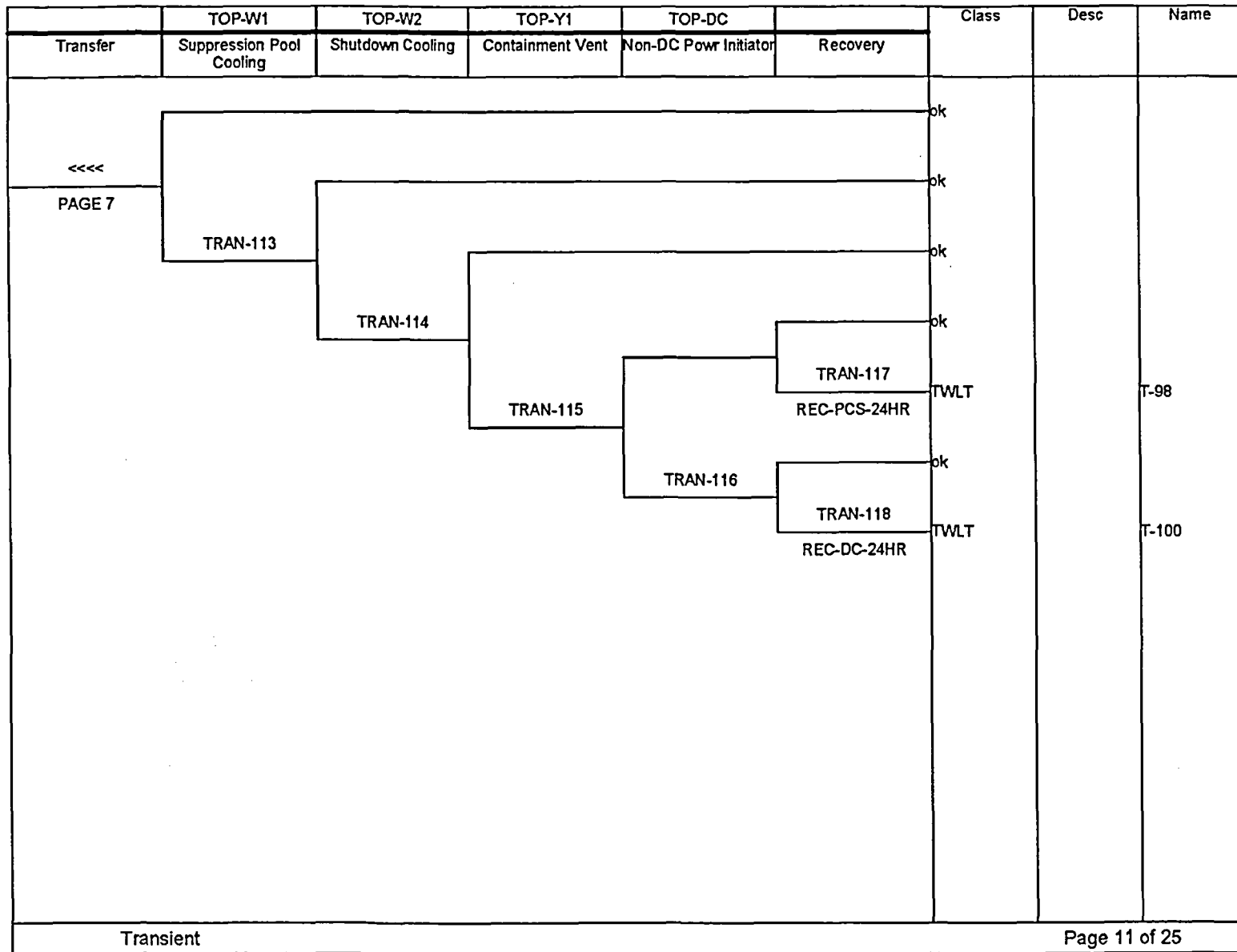


Figure C.3-1 Transient Event Tree (Continue)



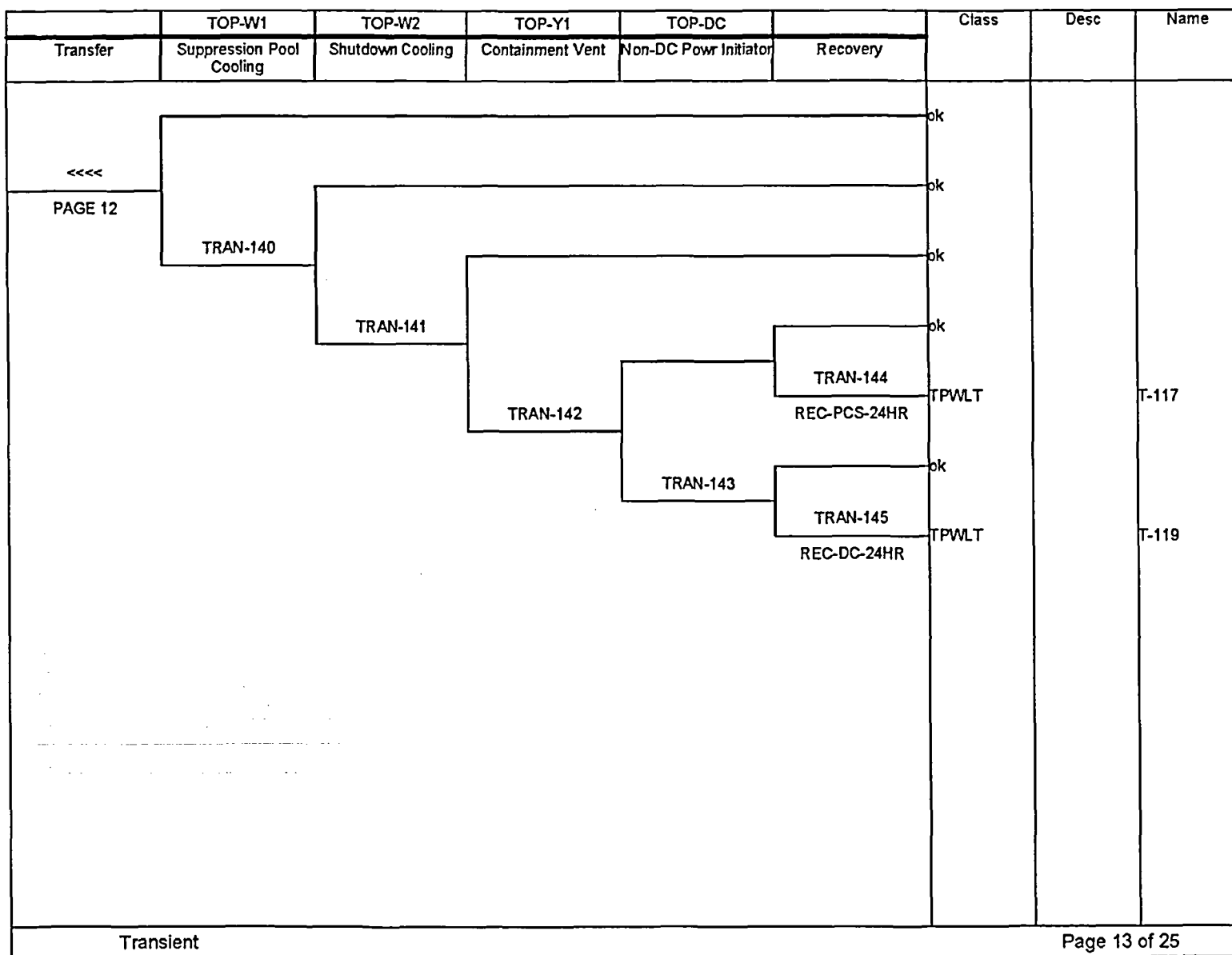


Figure C.3-1 Transient Event Tree (Continue)

	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW	TOP-DC		Class	Desc	Name
Transfer	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection	Non-DC Power Initiator	Recovery			
<<<<							ok		
PAGE 12							ok		
	TRAN-146						ok		
		TRAN-147					ok		
			TRAN-148				ok		
				TRAN-149			ok		
					TRAN-150	TRAN-151 REC-PCS-24HR	TWDT		T-127
						TRAN-152 REC-DC-24HR	TWDT		T-129
Transient									

Page 14 of 25

Figure C.3-1 Transient Event Tree (Continue)

	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW	TOP-DC		Class	Desc	Name
Transfer	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection	Non-DC Power Initiator	Recovery			
							ok		
<<<<							ok		
PAGE 12							ok		
	TRAN-153						ok		
		TRAN-154					ok		
			TRAN-155				ok		
				TRAN-156			ok		
					TRAN-157	TRAN-158 REC-PCS-24HR	TWDT		T-141
						TRAN-159 REC-DC-24HR	TWDT		T-143
Transient							Page 15 of 25		

Figure C.3-1 Transient Event Tree (Continue)

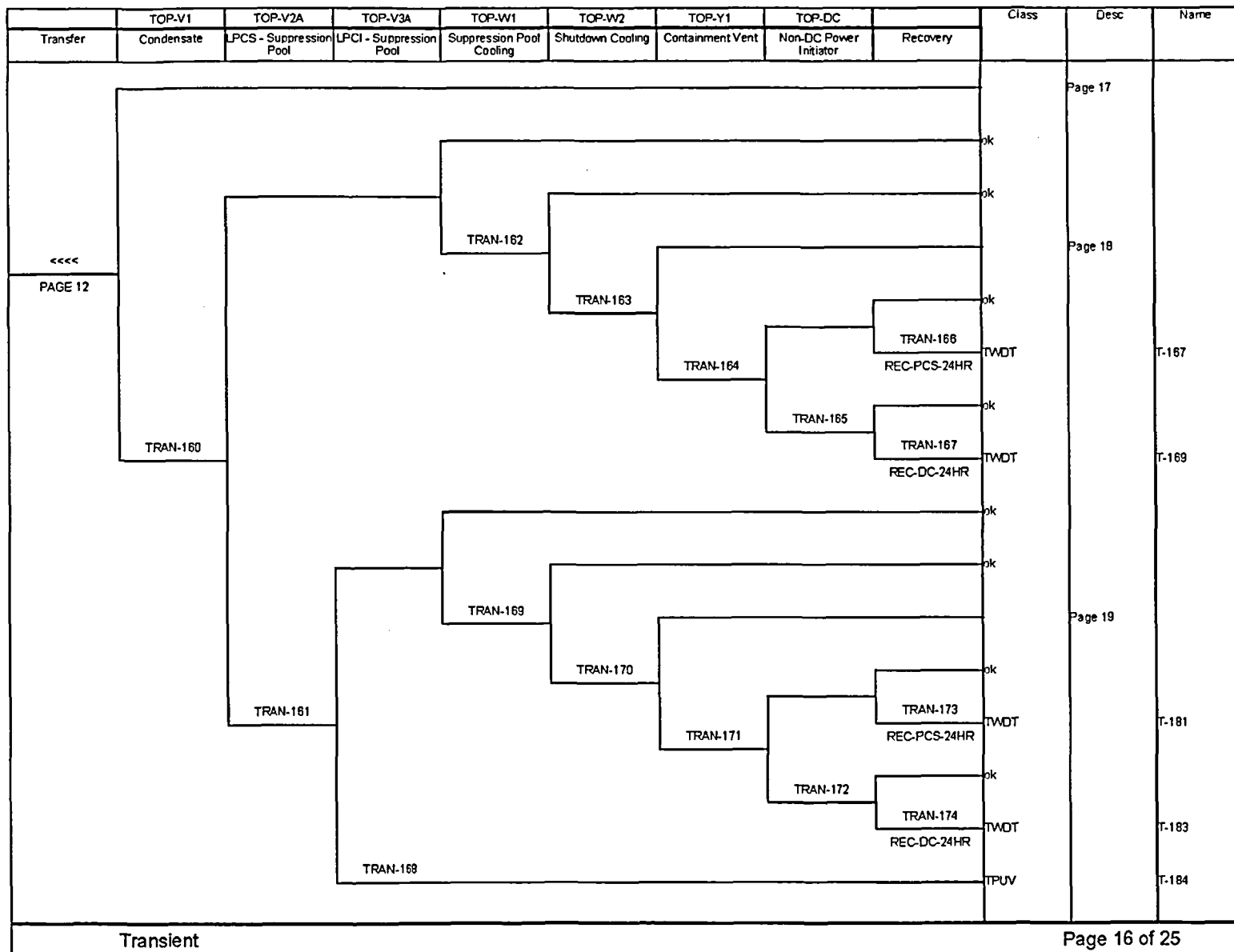


Figure C.3-1 Transient Event Tree (Continue)

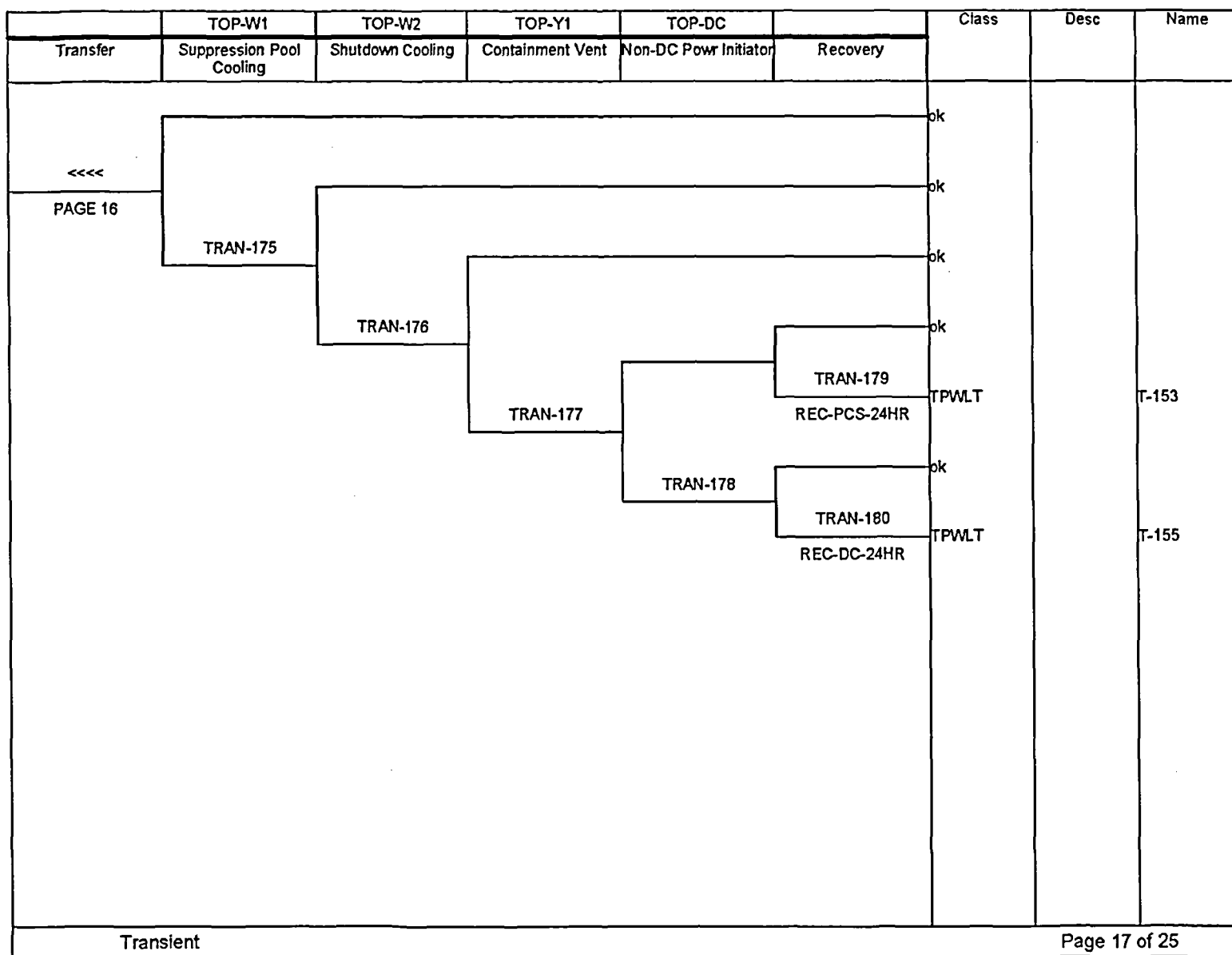


Figure C.3-1 Transient Event Tree (Continue)

	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW	TOP-DC		Class	Desc	Name
Transfer	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection	Non-DC Power Initiator	Recovery			
							ok		
<<<<							ok		
PAGE 16							ok		
	TRAN-181						ok		
		TRAN-182					ok		
			TRAN-183				ok		
				TRAN-184			ok		
					TRAN-186 REC-PCS-24HR		TWDT		T-163
					TRAN-185 TRAN-187 REC-DC-24HR		TWDT		T-165
Transient							Page 18 of 25		

Figure C.3-1 Transient Event Tree (Continue)

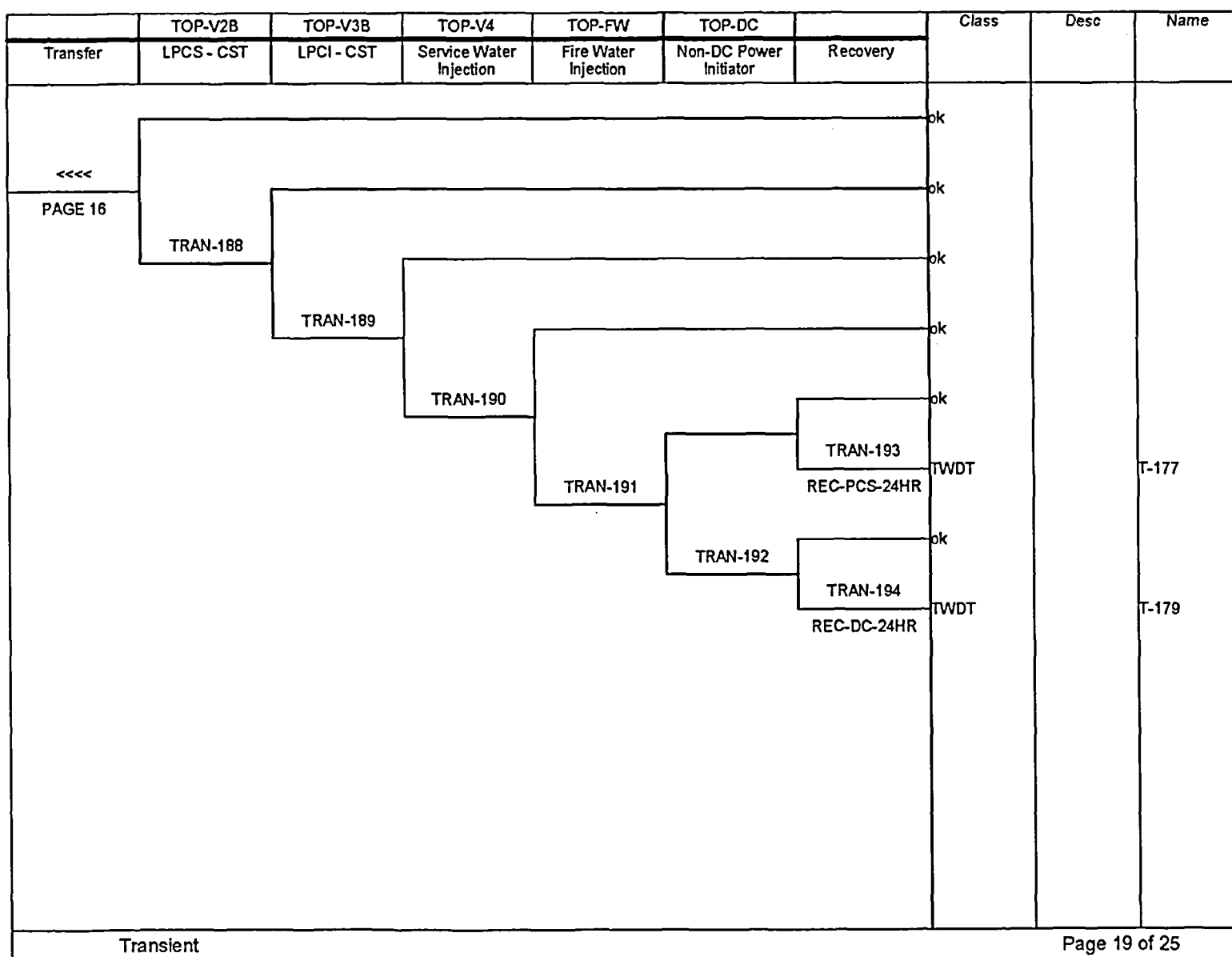


Figure C.3-1 Transient Event Tree (Continue)

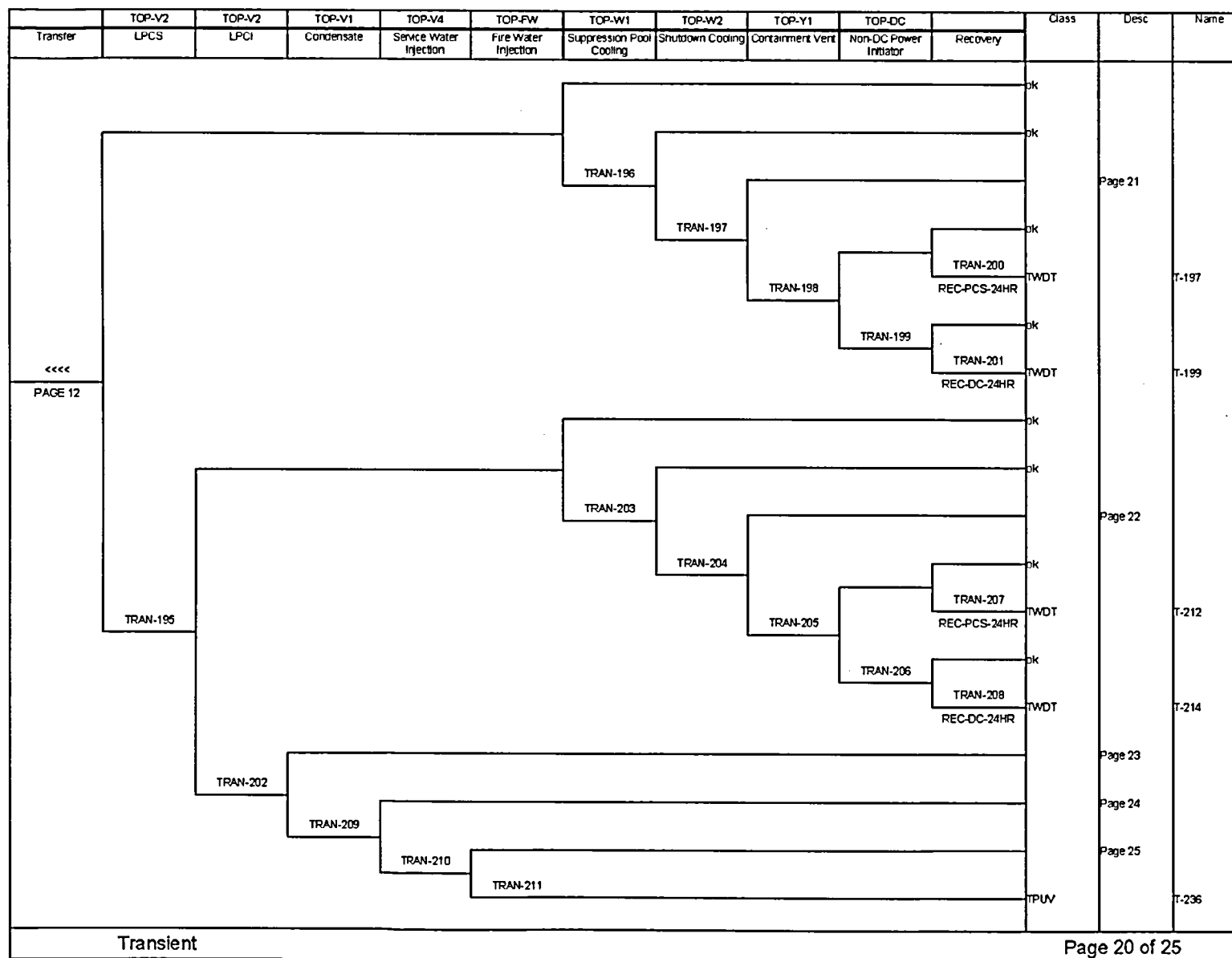


Figure C.3-1 Transient Event Tree (Continue)

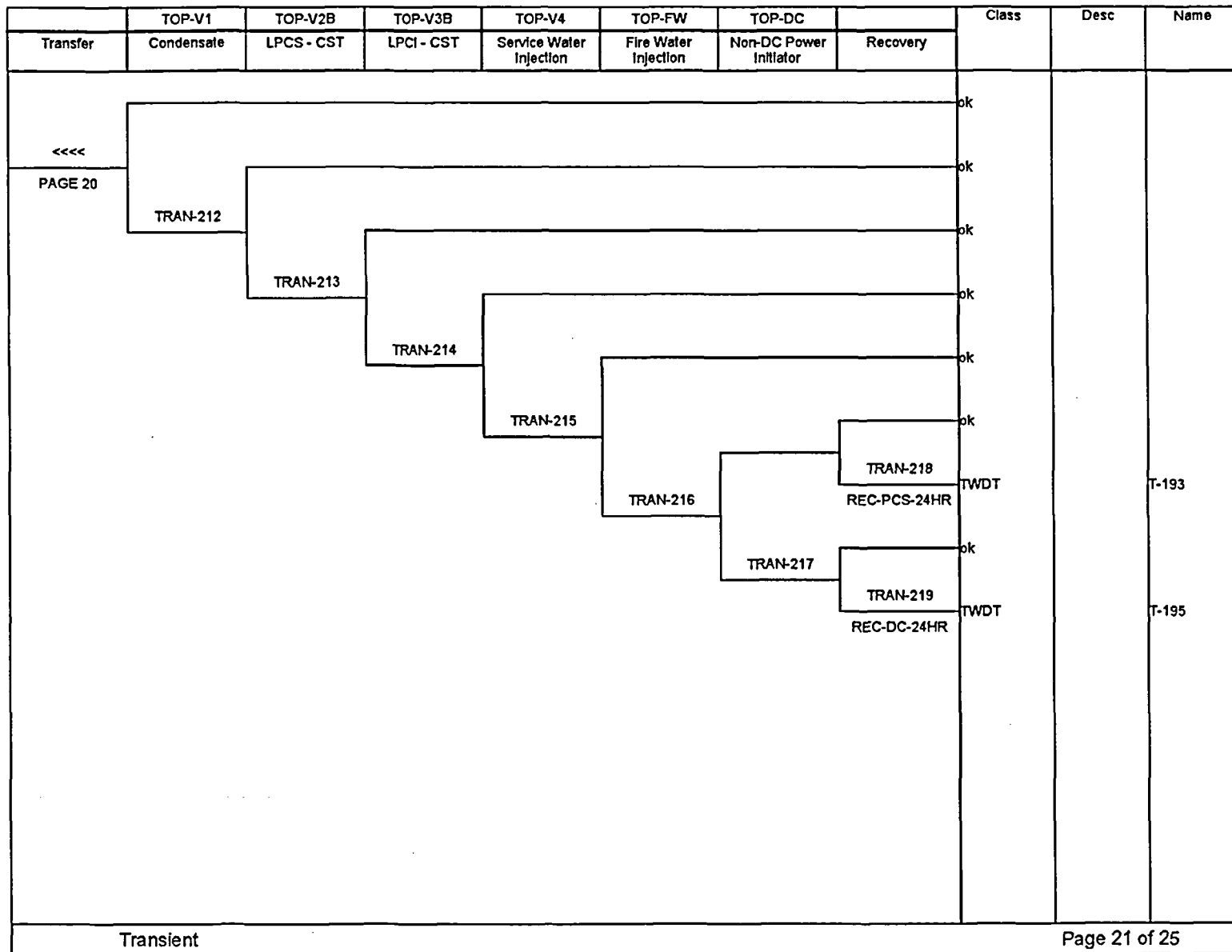


Figure C.3-1 Transient Event Tree (Continue)

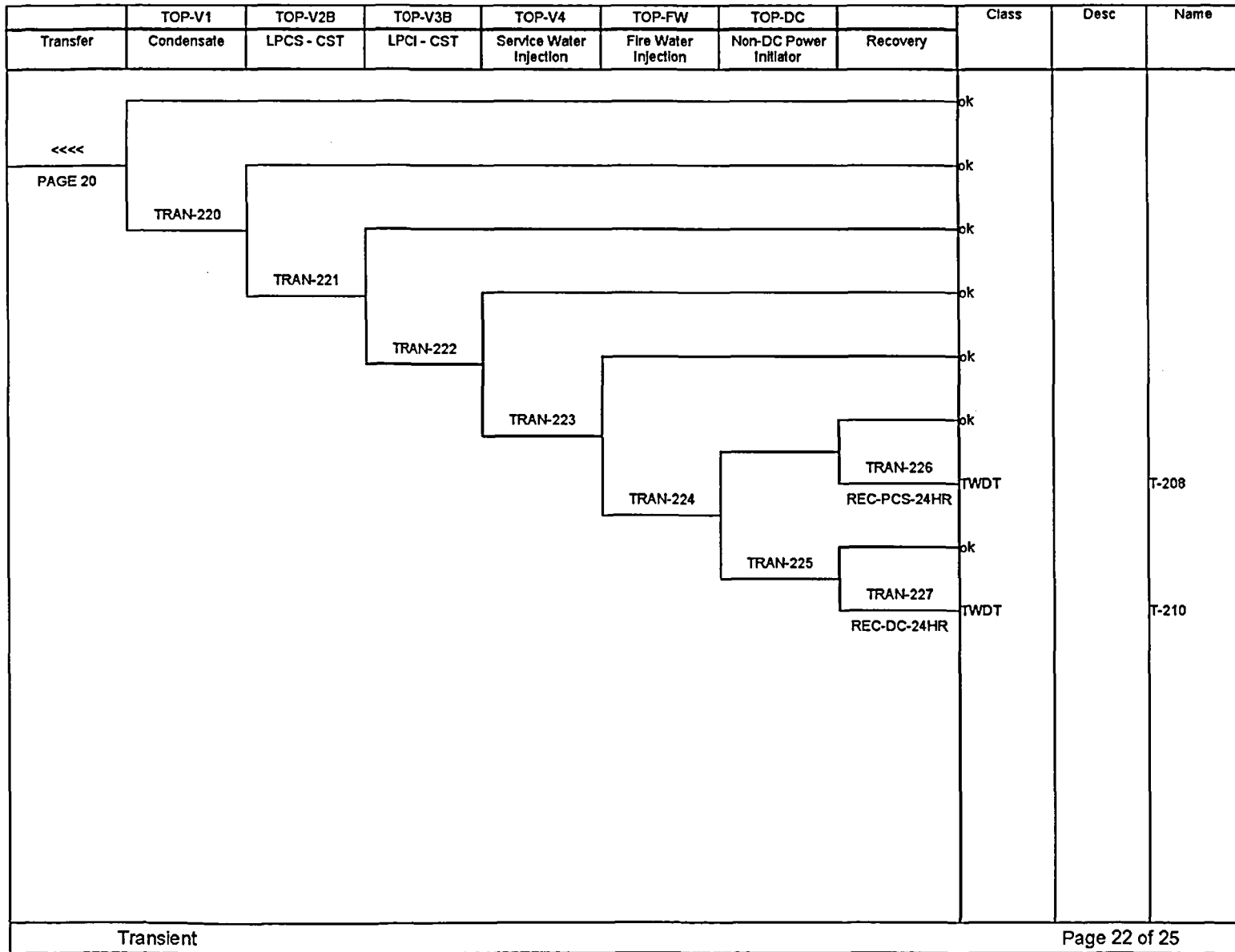


Figure C.3-1 Transient Event Tree (Continue)

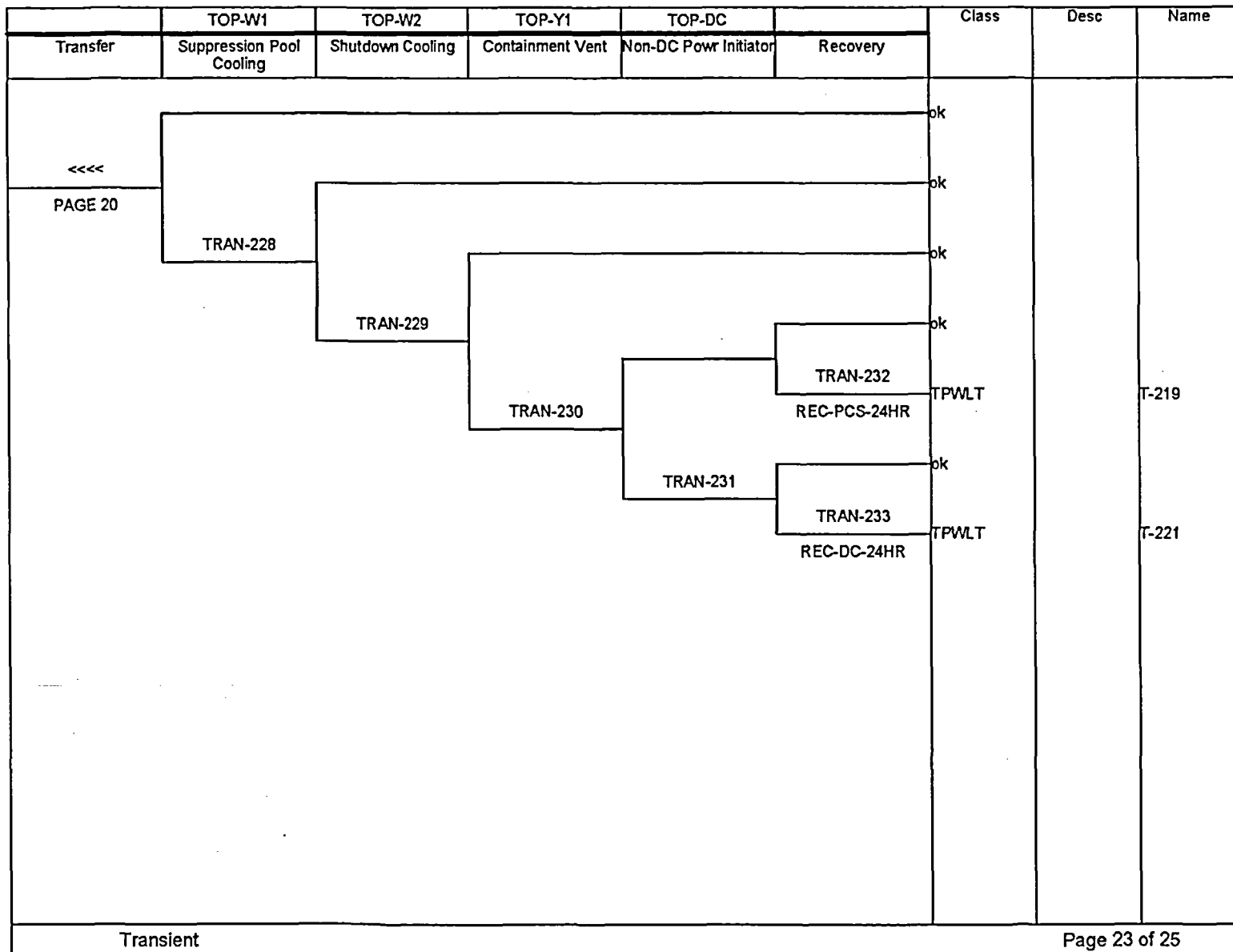


Figure C.3-1 Transient Event Tree (Continue)

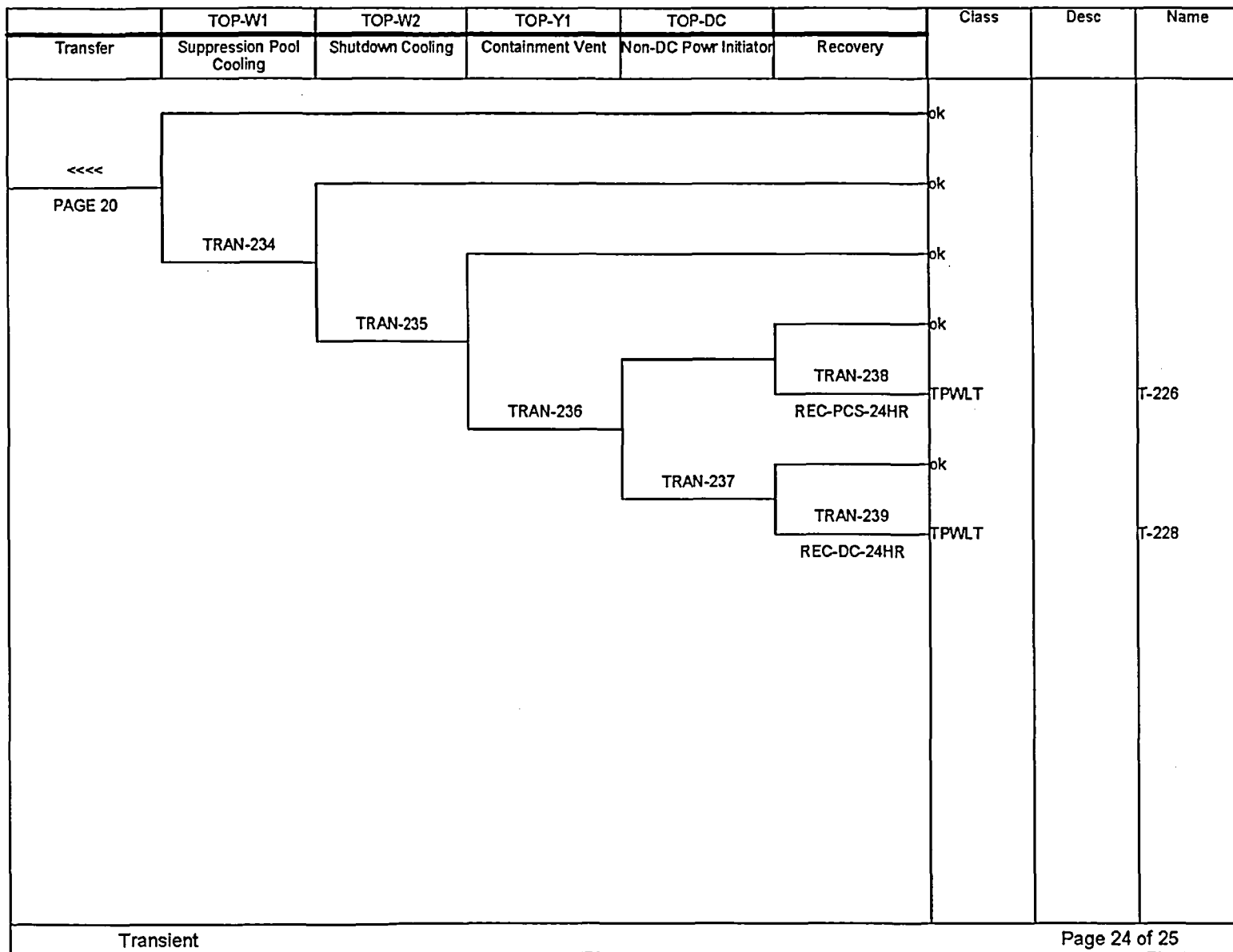


Figure C.3-1 Transient Event Tree (Continue)

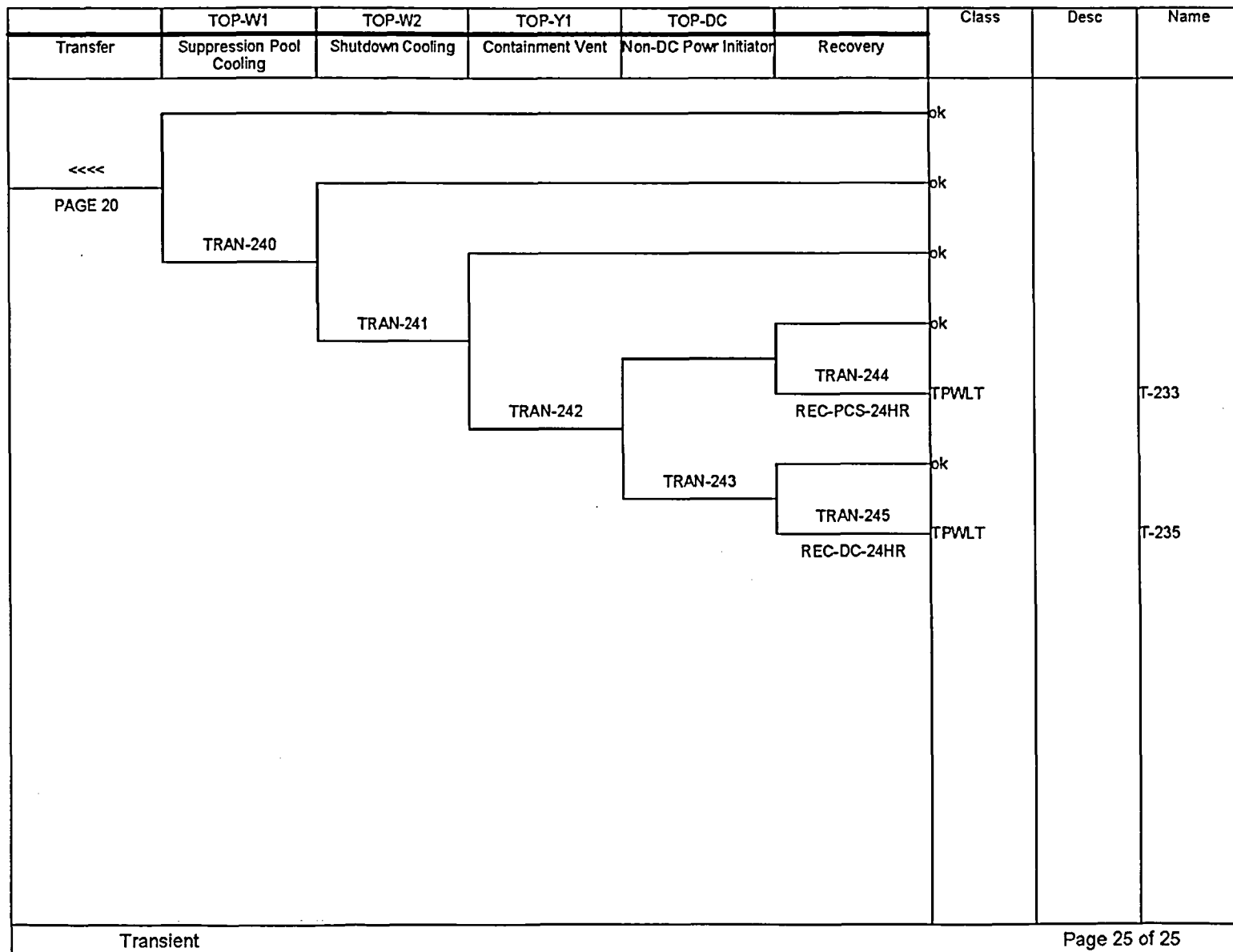


Figure C.3-1 Transient Event Tree (Continue)

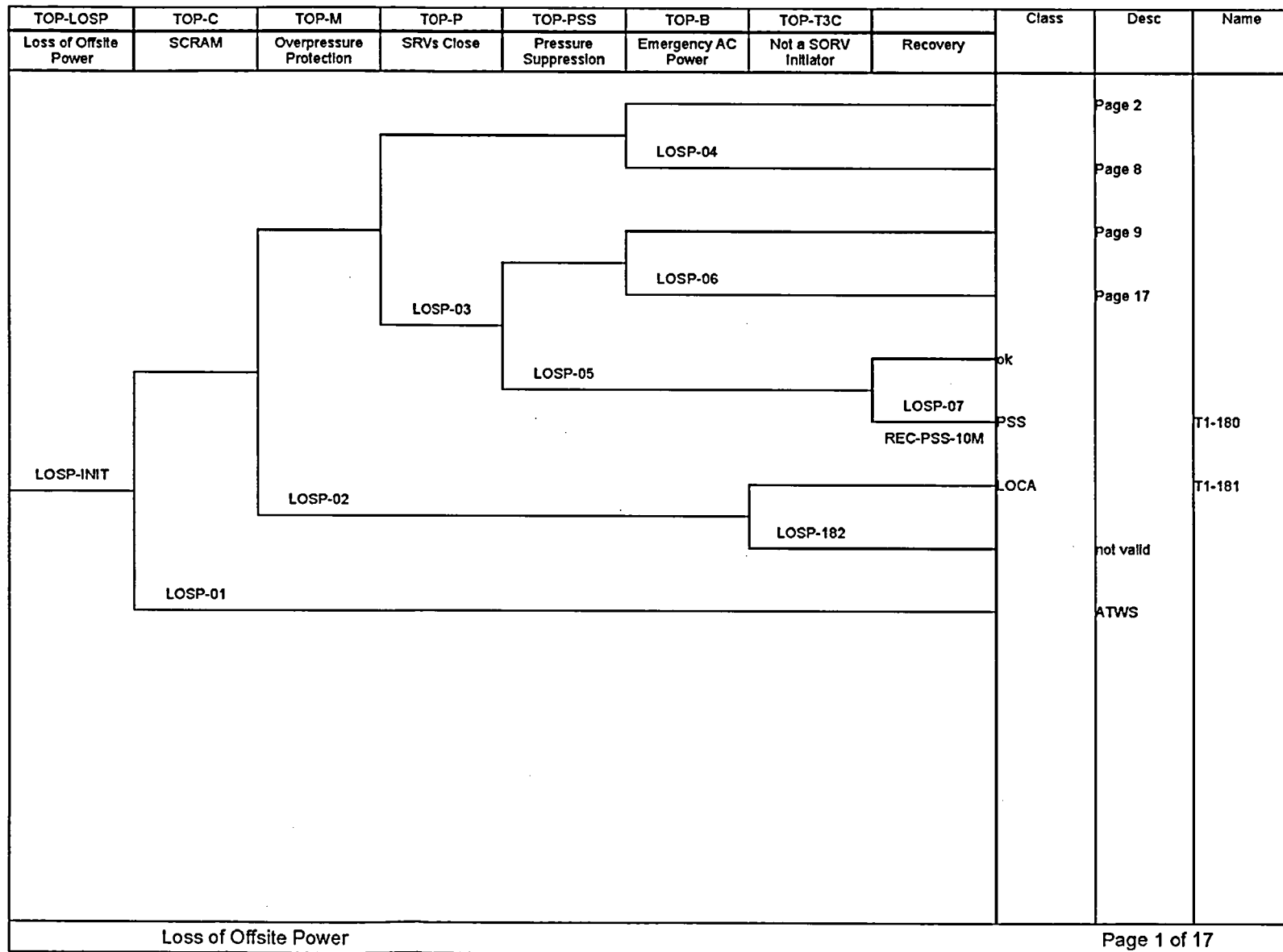


Figure C.3-2 Loss of Offsite Power Event Tree

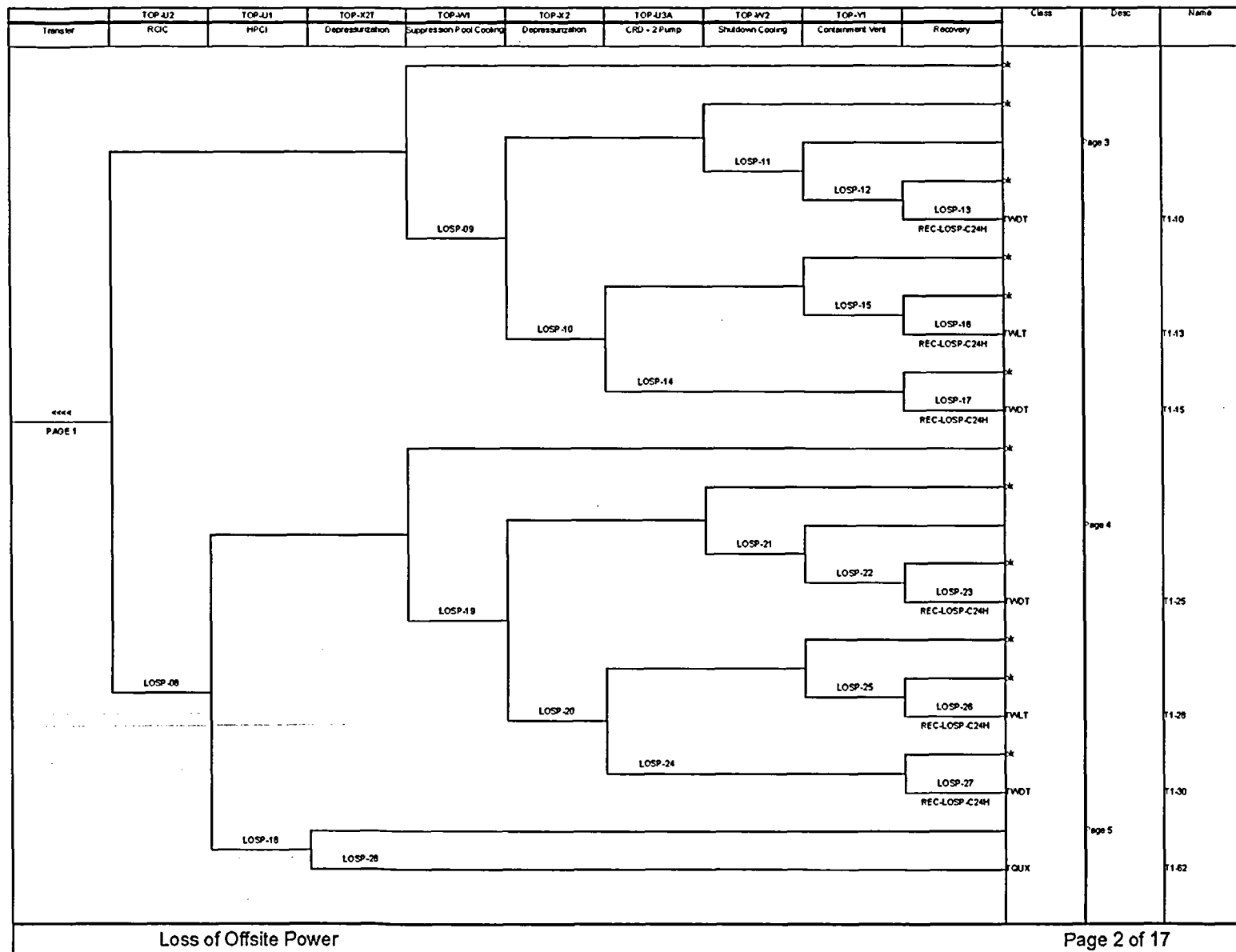


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

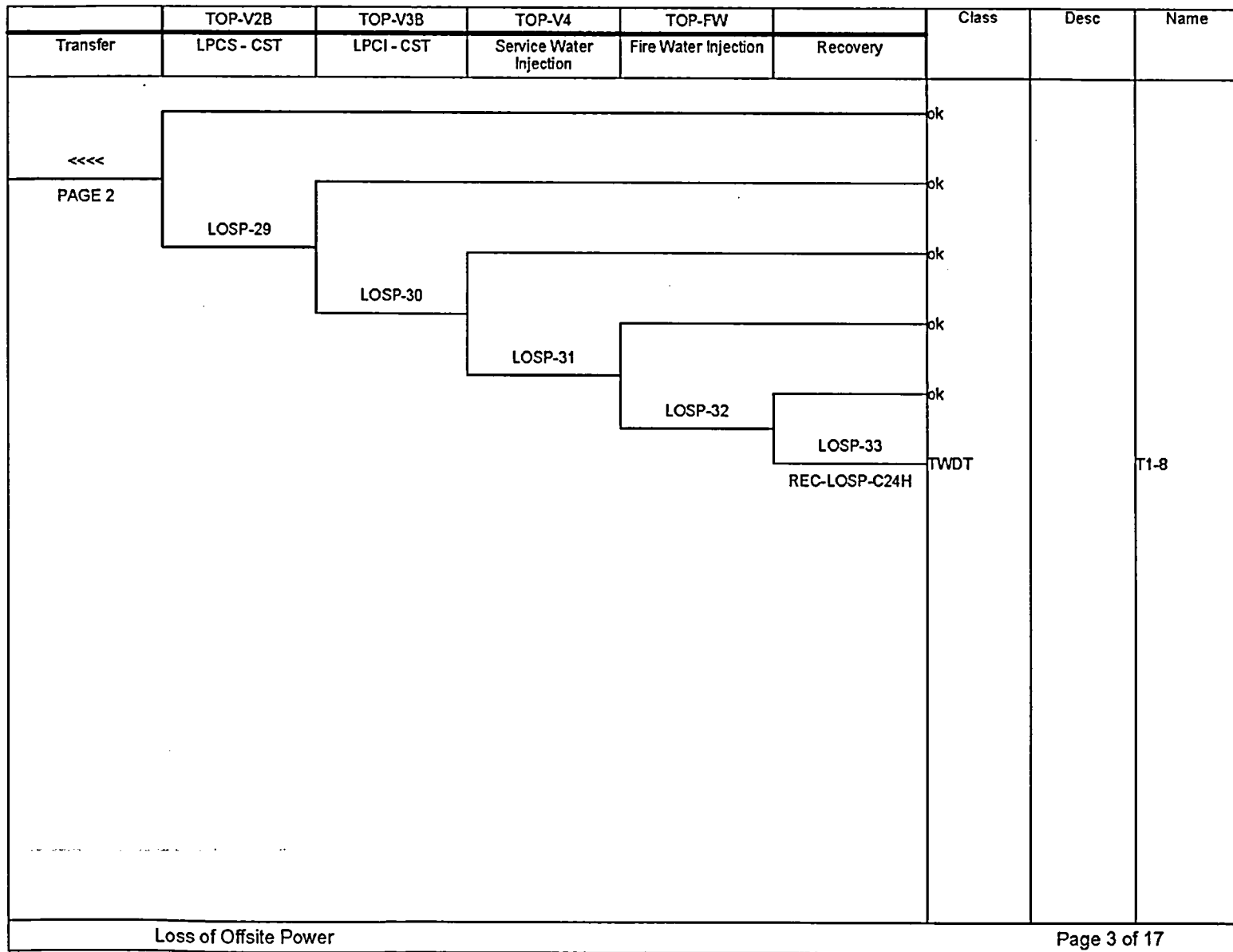


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

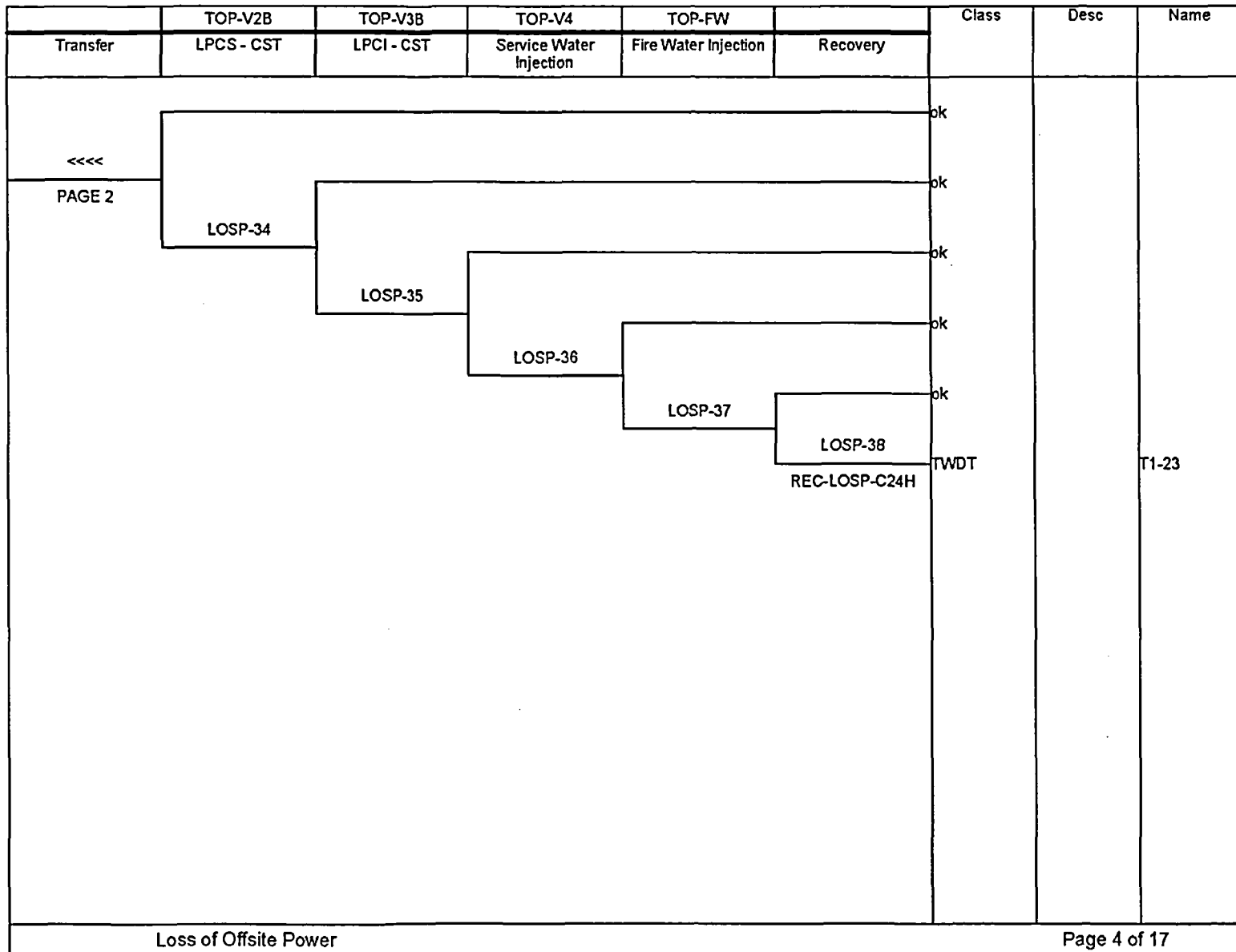


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

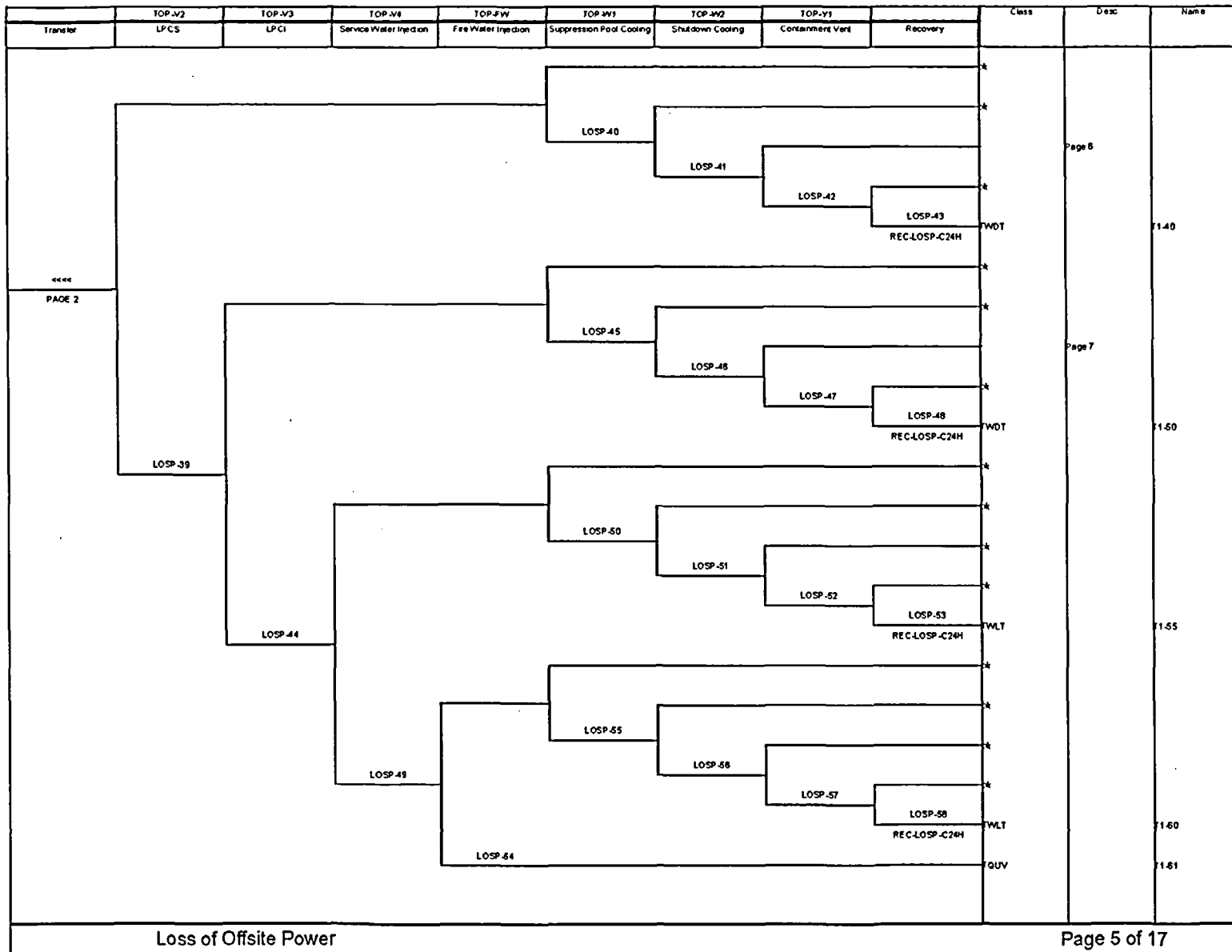


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW		Class	Desc	Name
Transfer	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection	Recovery			
<<<<						ok		
PAGE 5						ok		
	LOSP-59					ok		
		LOSP-60				ok		
			LOSP-61			ok		
				LOSP-62		ok		
					LOSP-63	TWDT		T1-38
					REC-LOSP-C24H			
Loss of Offsite Power								

Page 6 of 17

Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

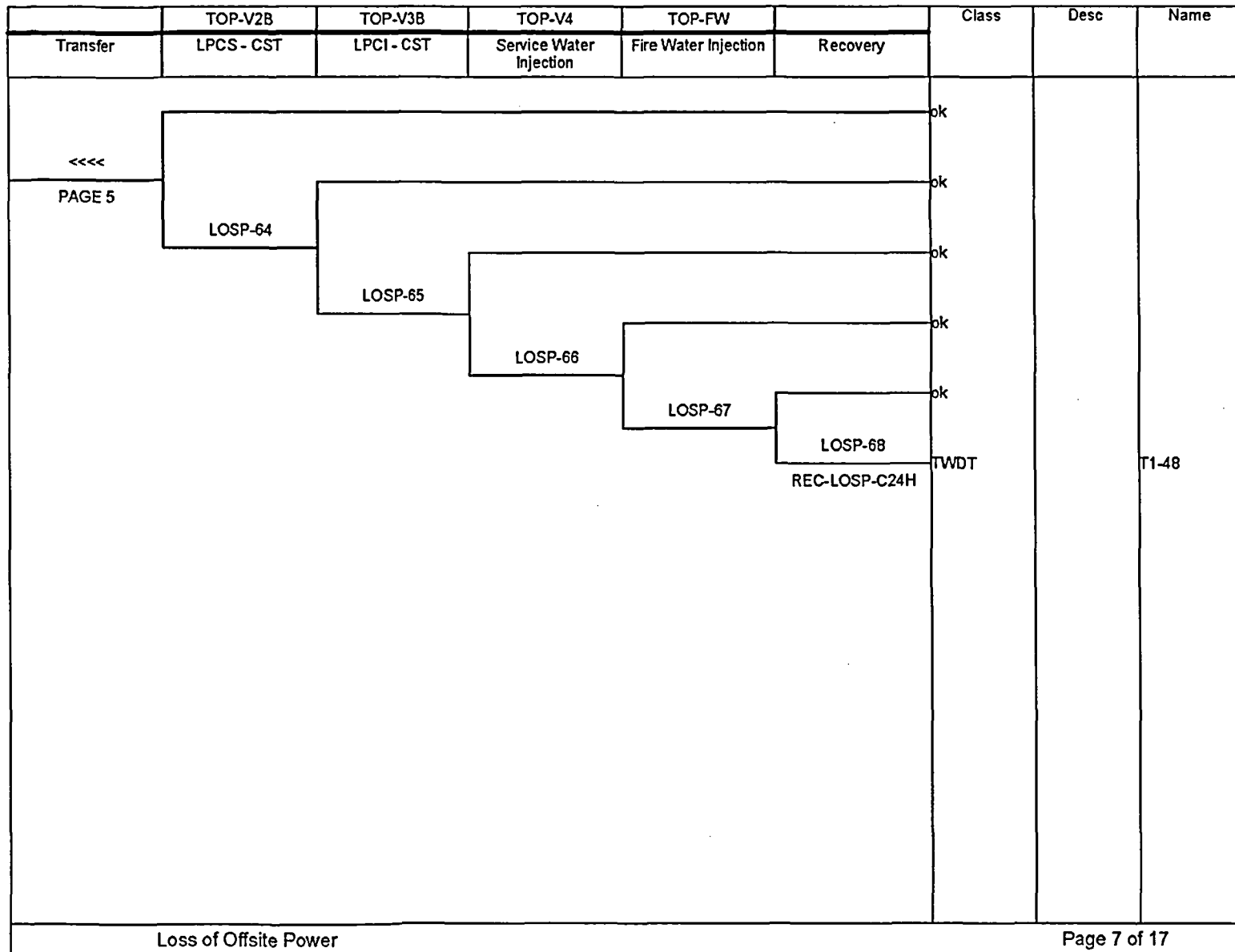


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

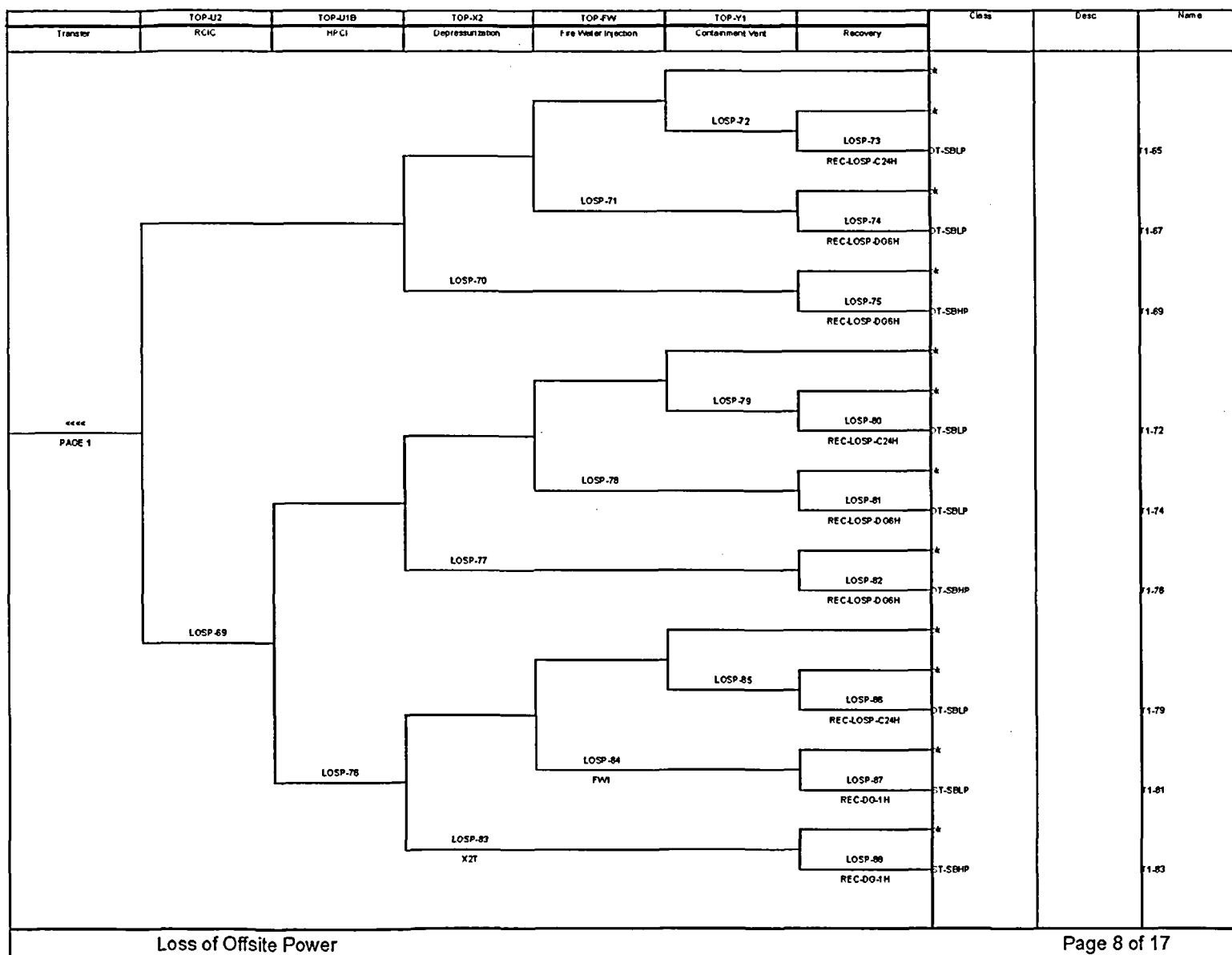


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)



	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW		Class	Desc	Name
Transfer	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection	Recovery			
<<<<						ok		
PAGE 9						ok		
	LOSP-112					ok		
		LOSP-113				ok		
			LOSP-114			ok		
				LOSP-115		ok		
					LOSP-116 REC-LOSP-C24H	TWDT		T1-91
Loss of Offsite Power								

Page 10 of 17

Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

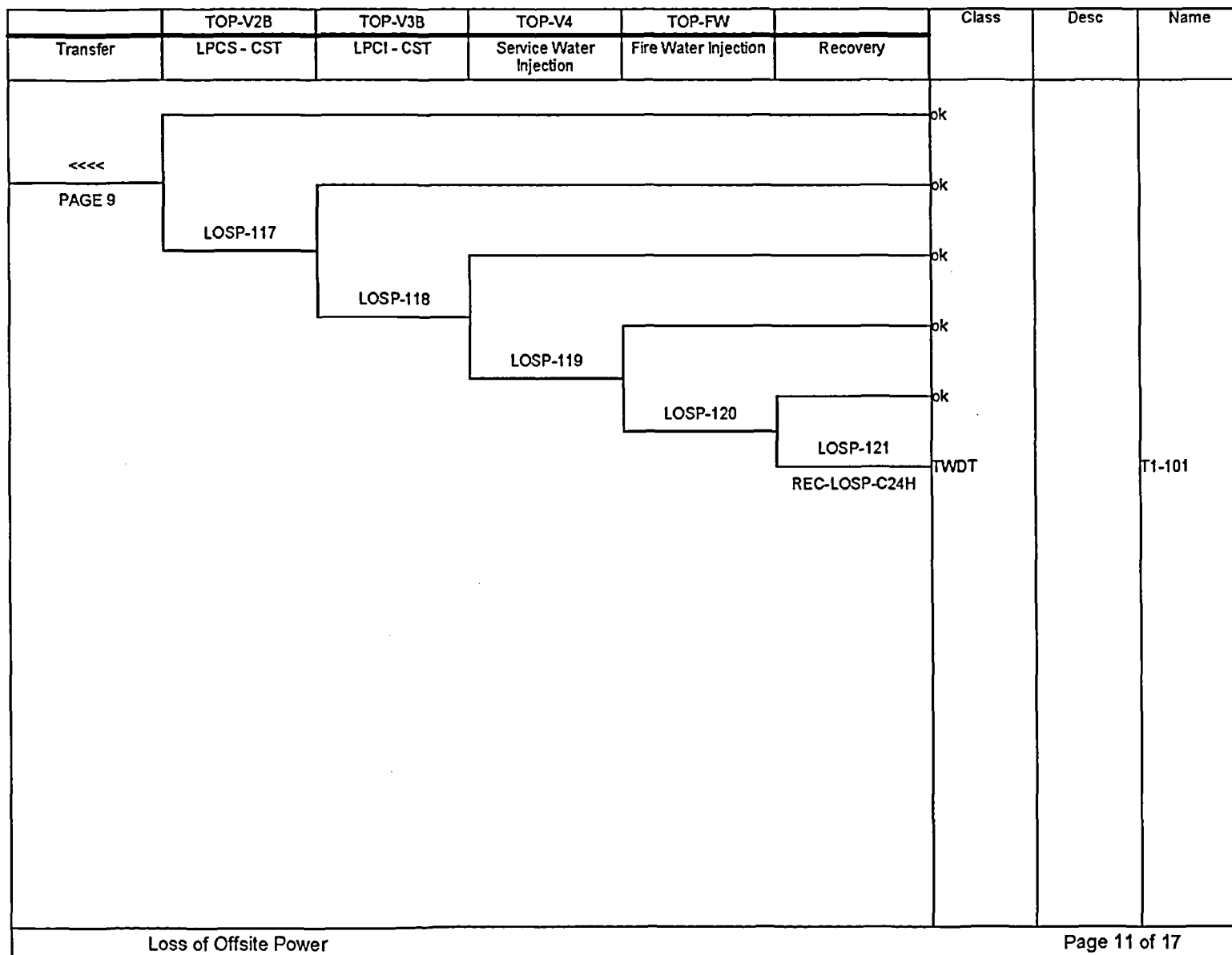


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW		Class	Desc	Name
Transfer	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection	Recovery			
<<<<						ok		
PAGE 9						ok		
	LOSP-122					ok		
		LOSP-123				ok		
			LOSP-124			ok		
				LOSP-125		ok		
					LOSP-126 REC-LOSP-C24H	TWDT		T1-112
Loss of Offsite Power							Page 12 of 17	

Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

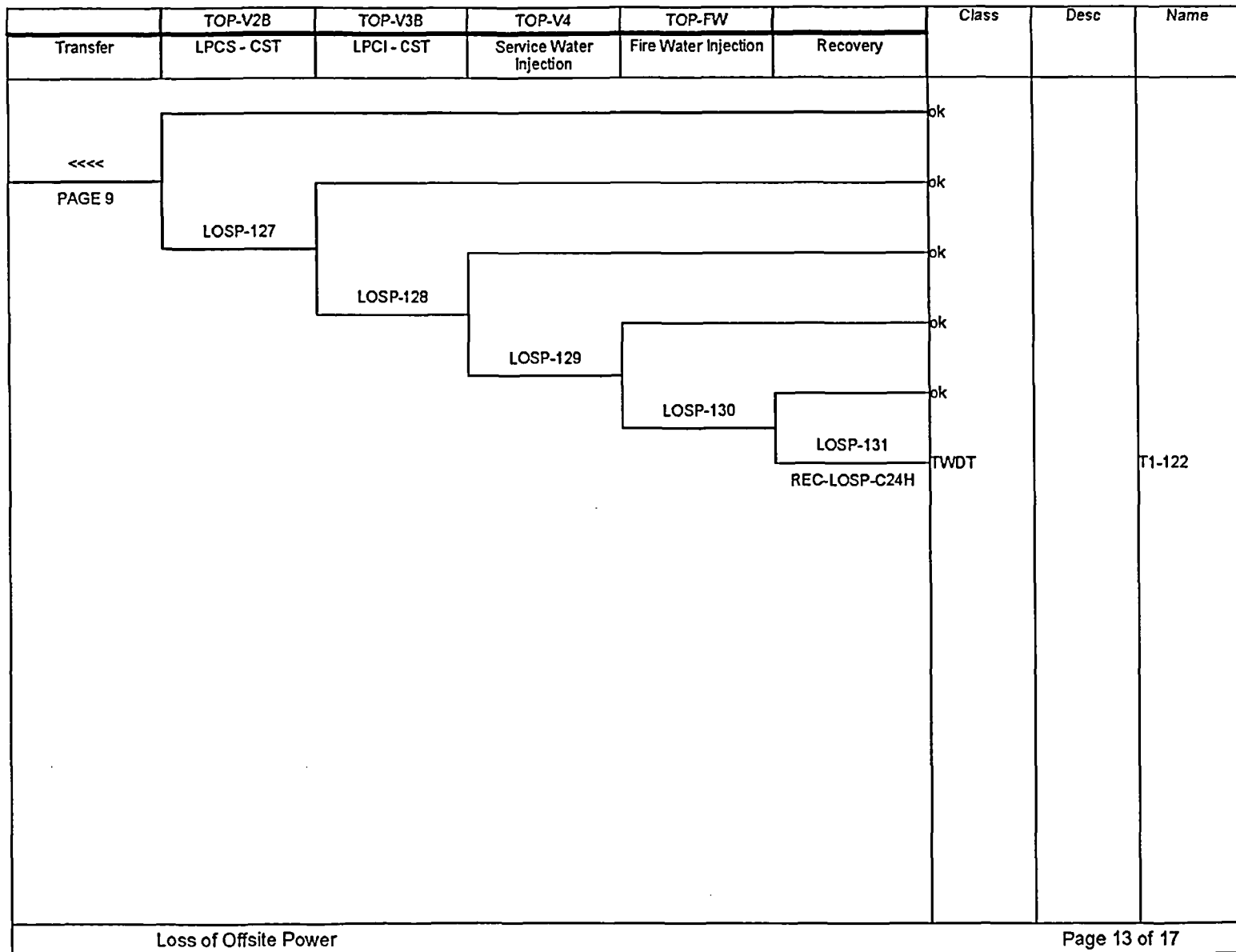


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

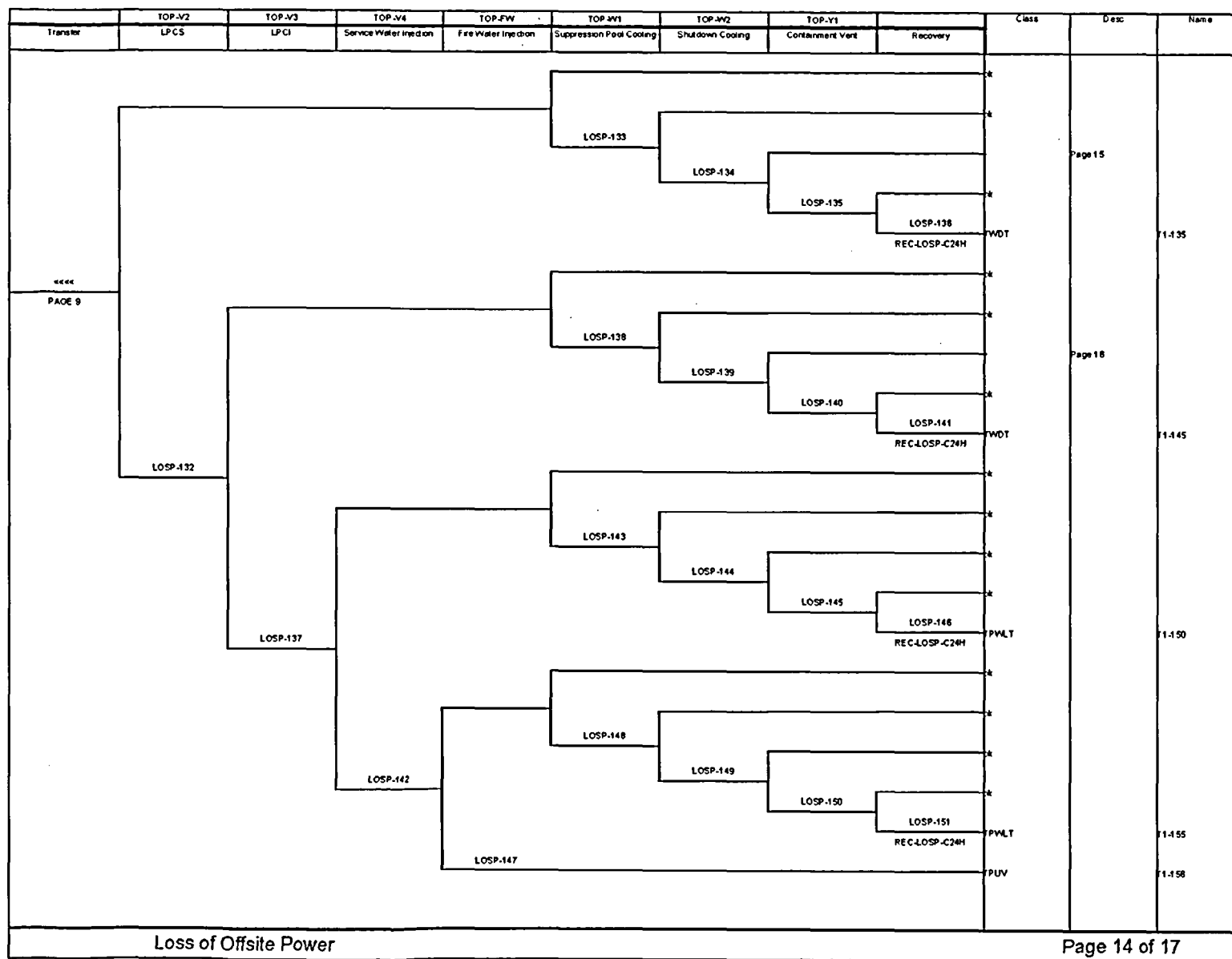


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

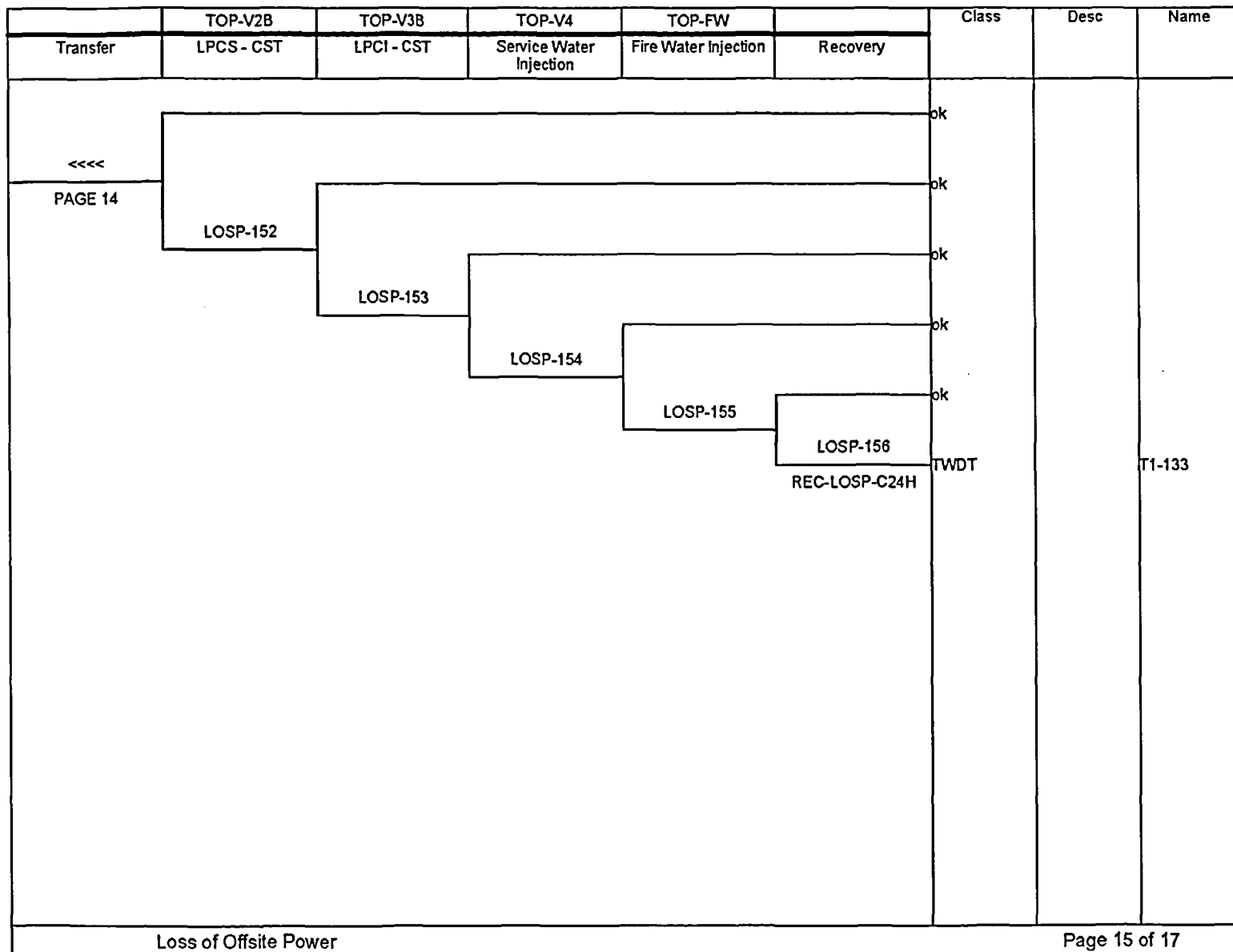


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

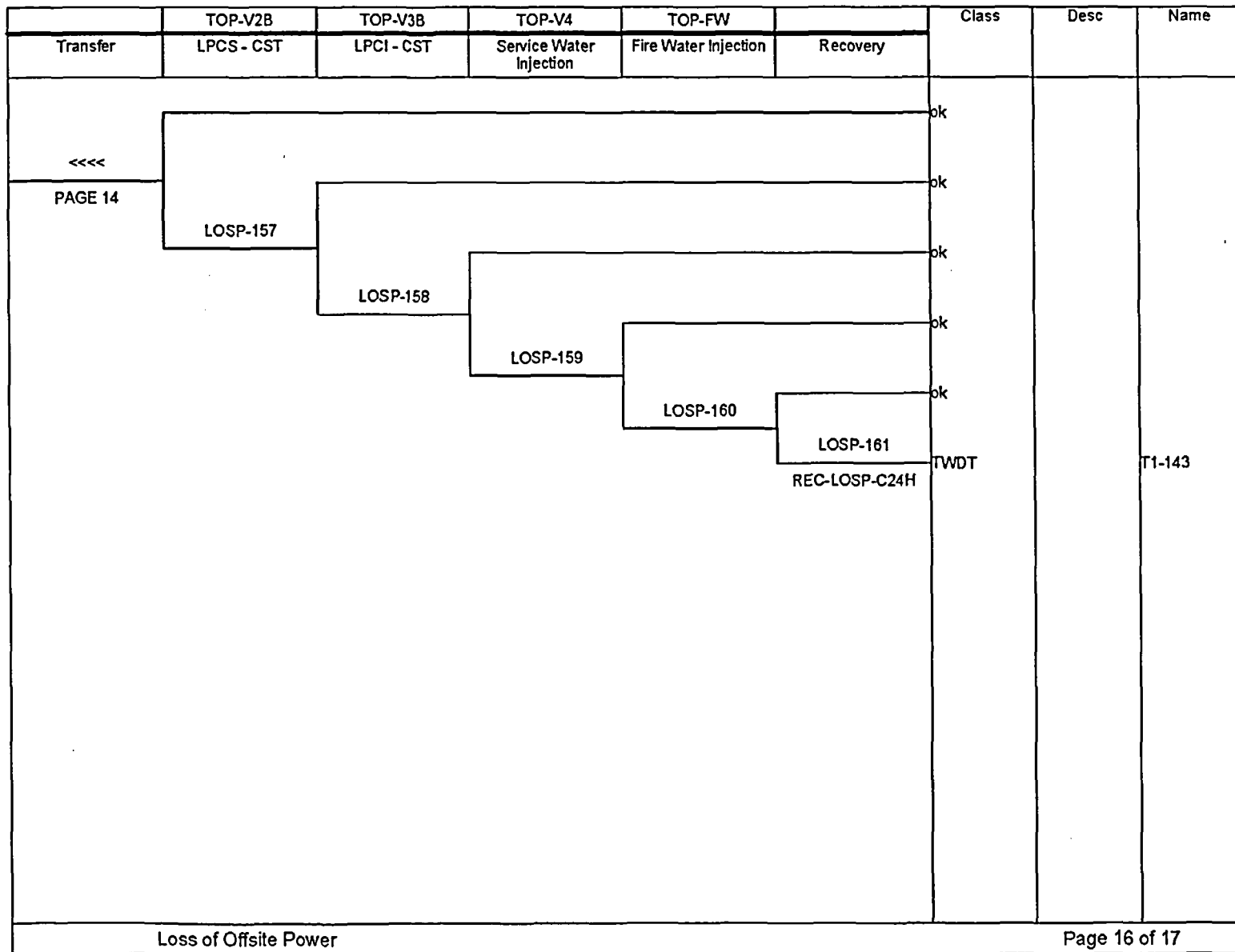


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)

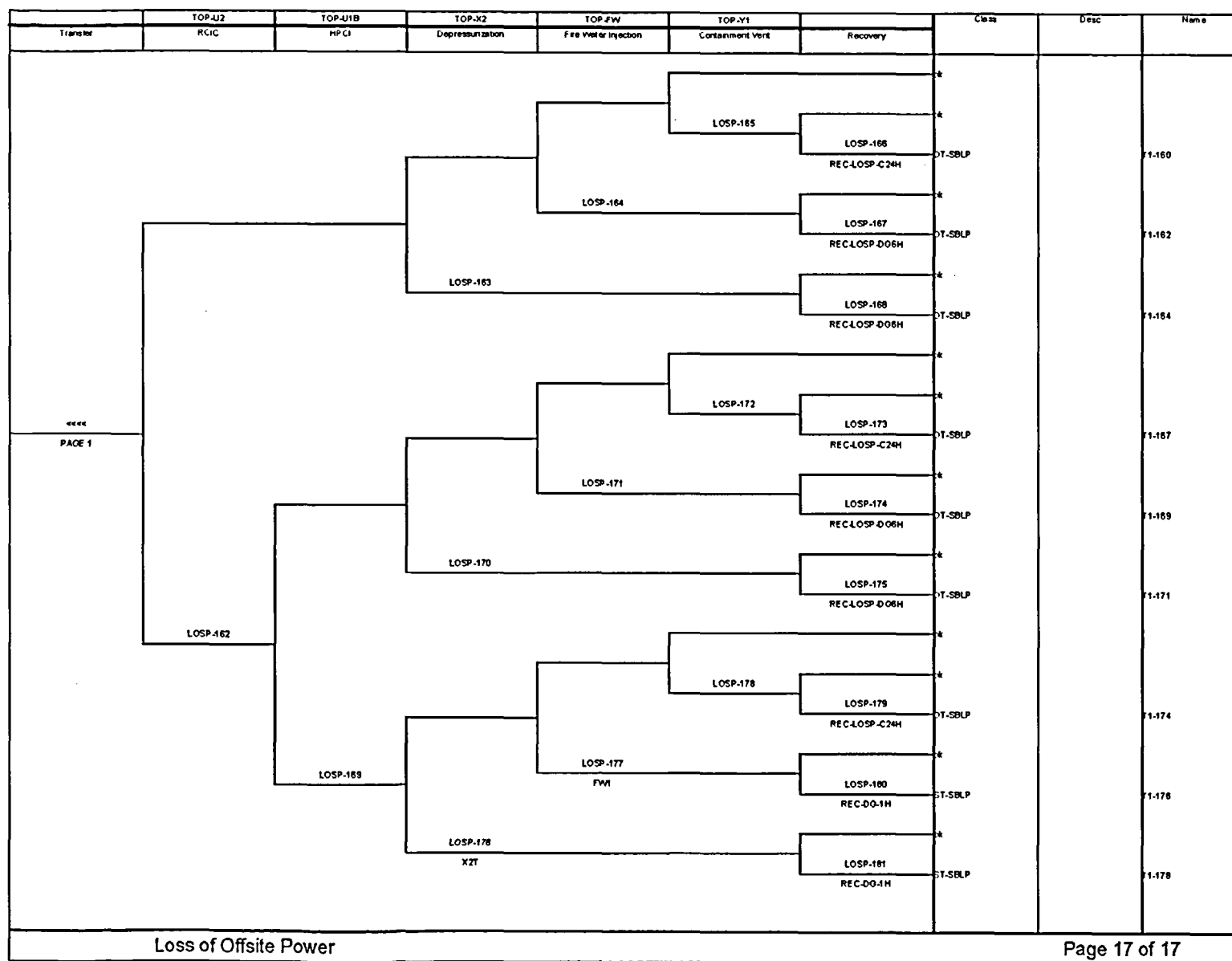
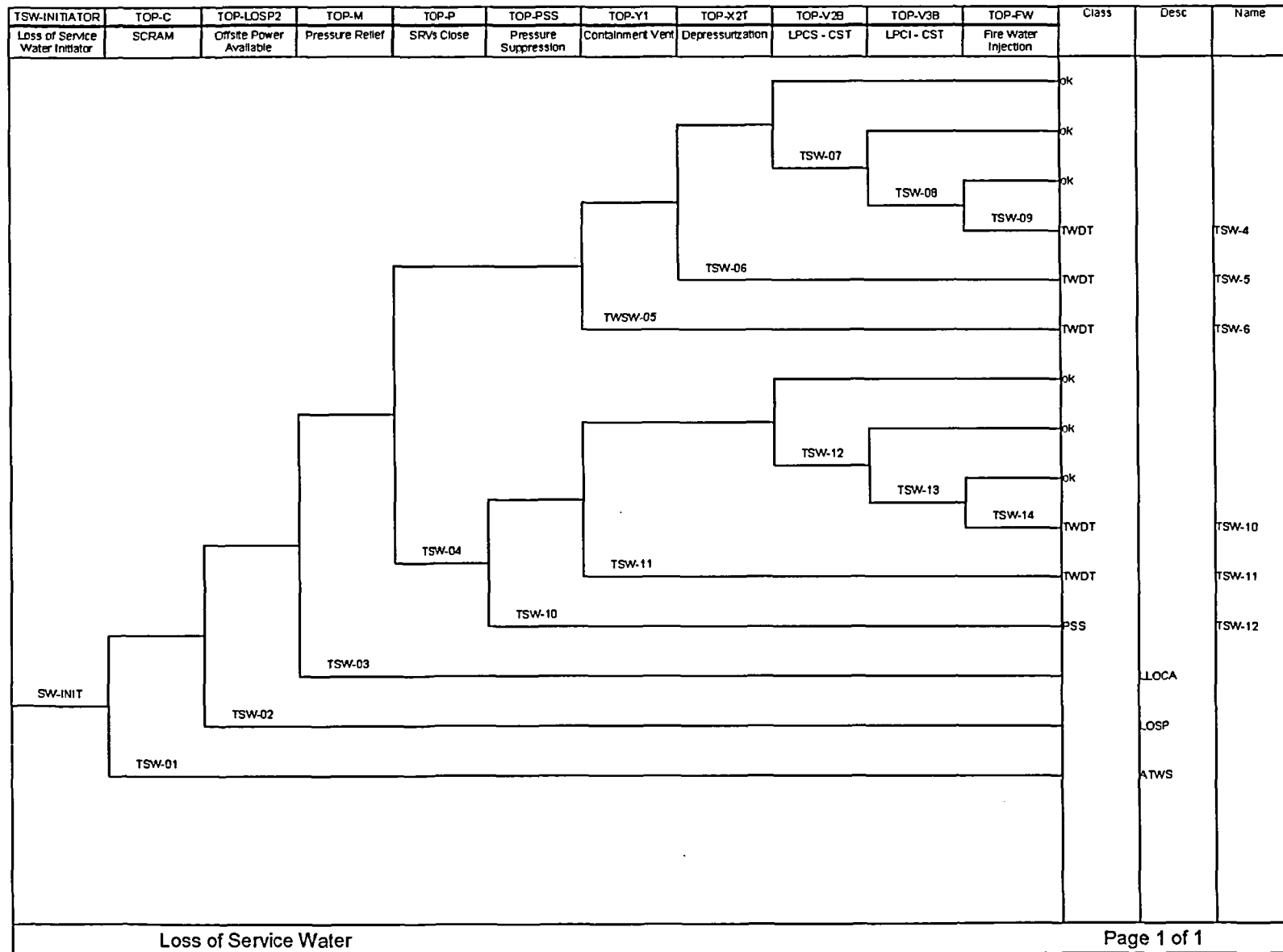


Figure C.3-2 Loss of Offsite Power Event Tree (Continue)



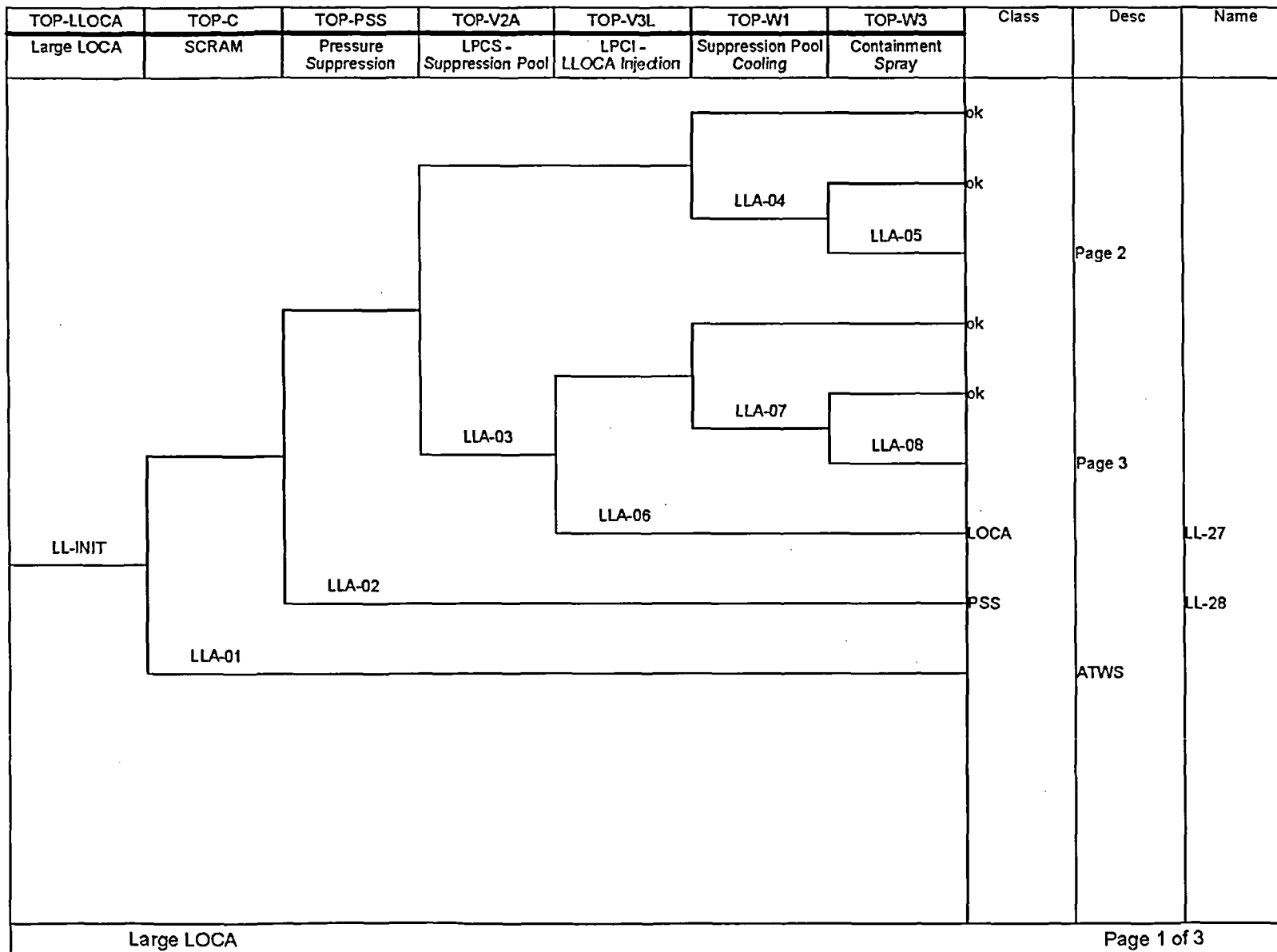


Figure C.3-4 Large LOCA Event Tree

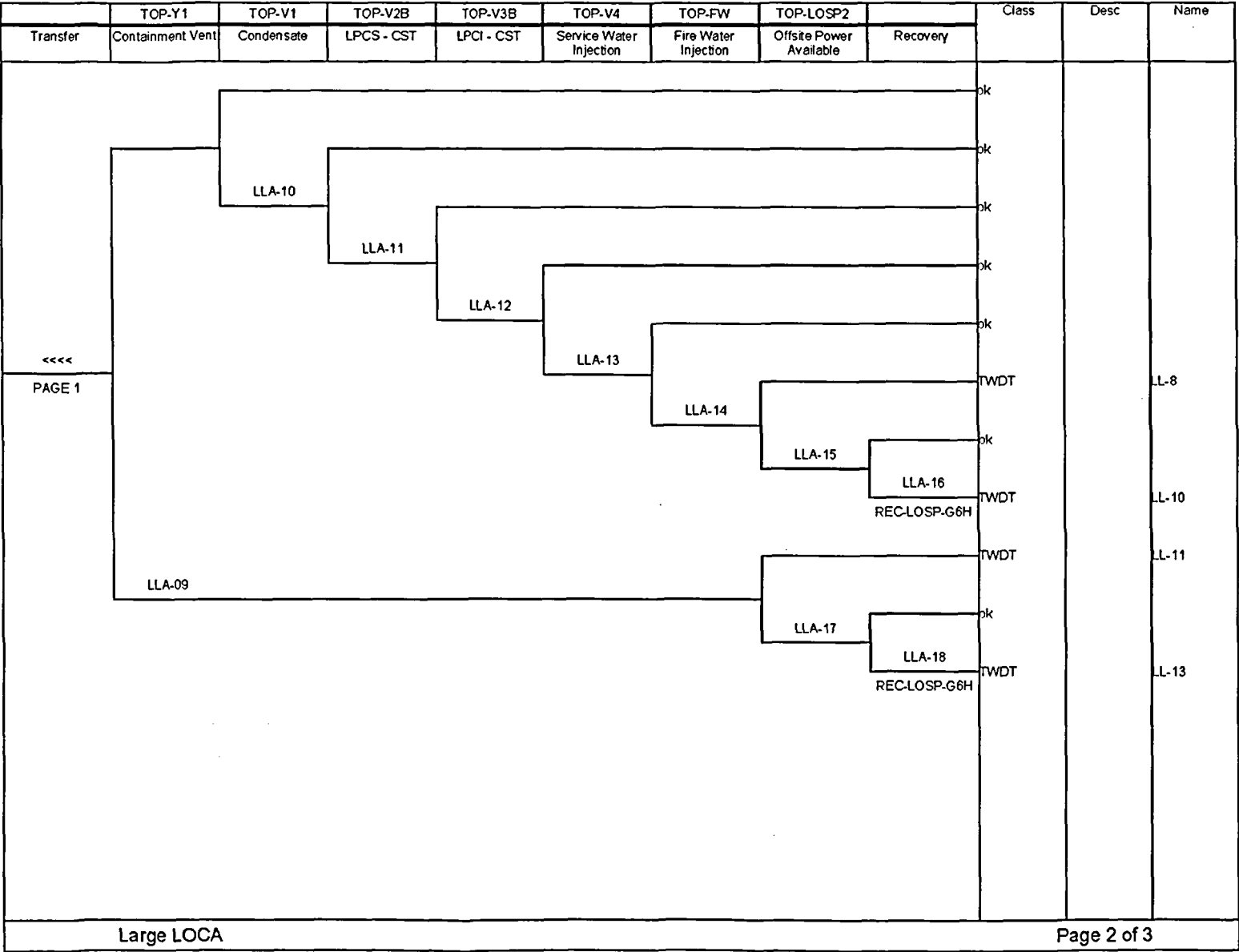


Figure C.3-4 Large LOCA Event Tree (Continue)

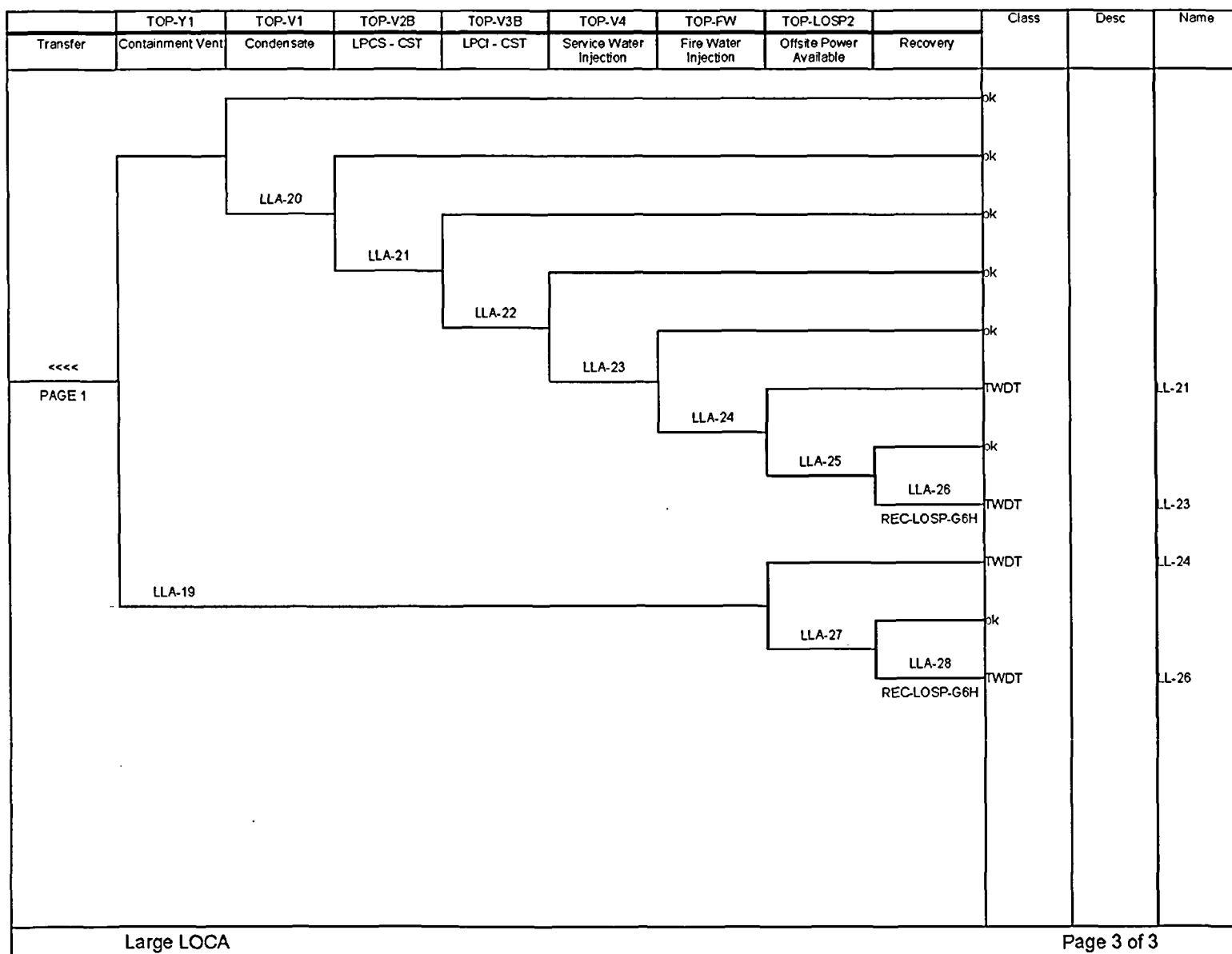


Figure C.3-4 Large LOCA Event Tree (Continue)

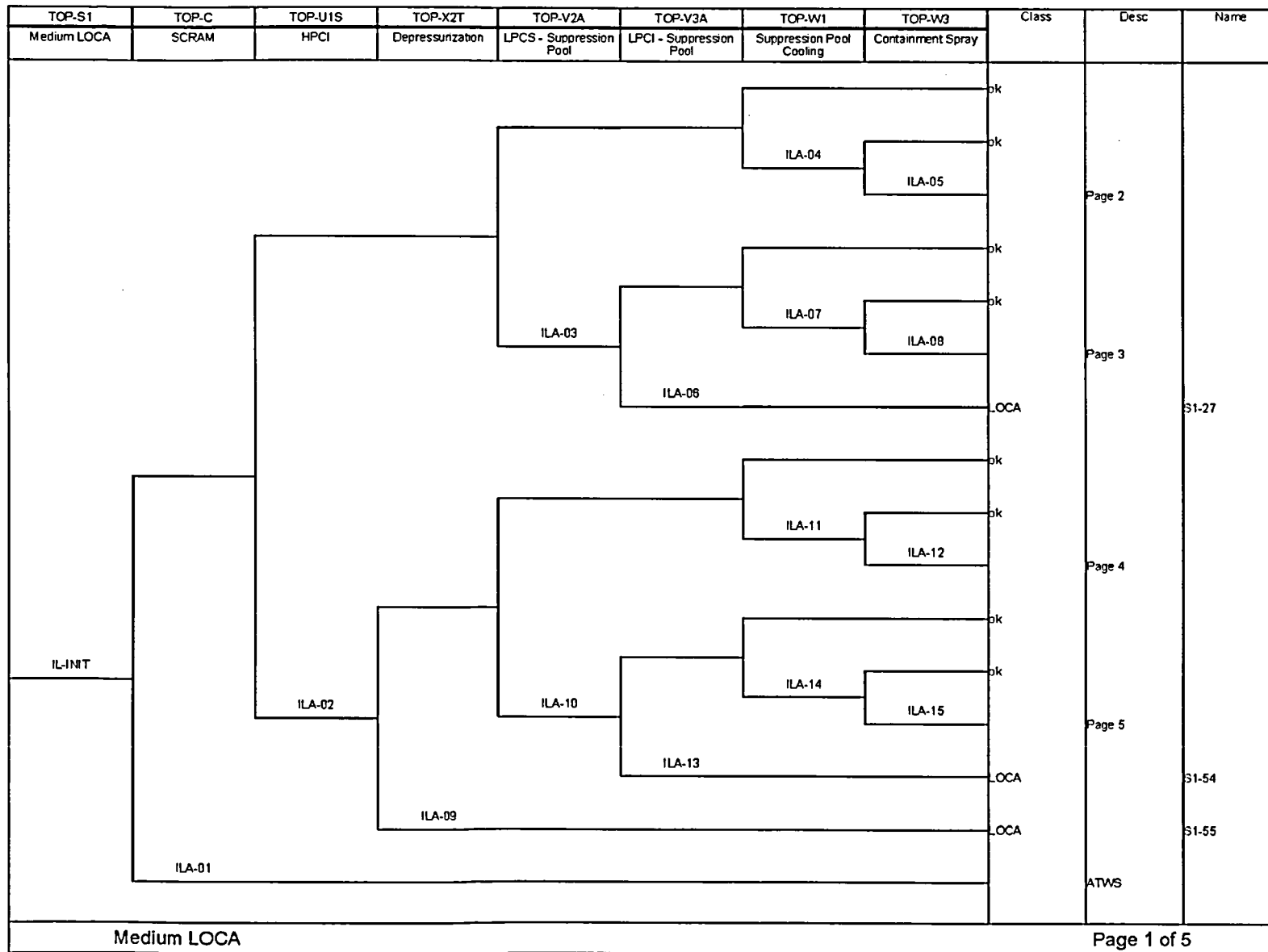


Figure C.3-5 Medium LOCA Event Tree

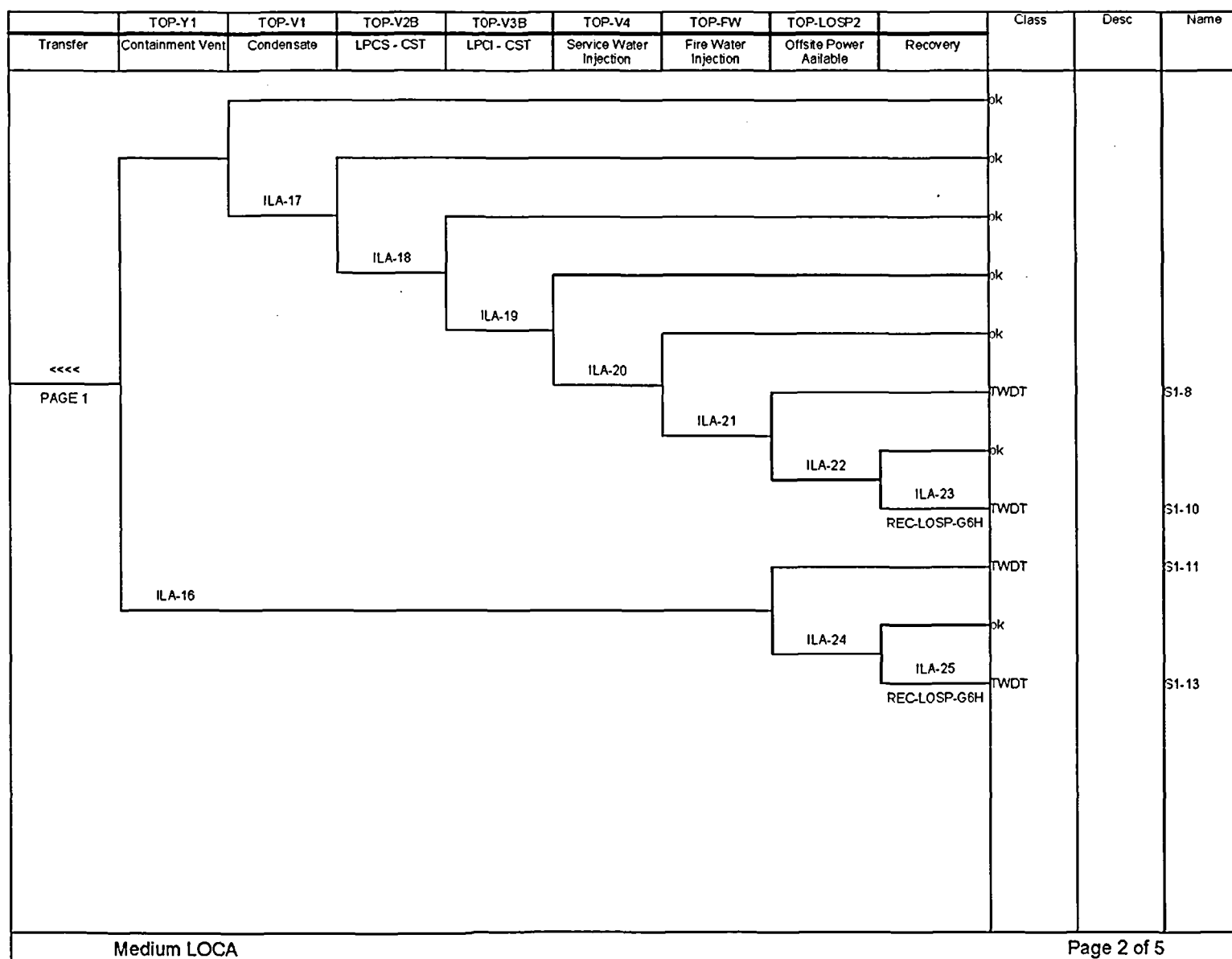


Figure C.3-5 Medium LOCA Event Tree (Continue)

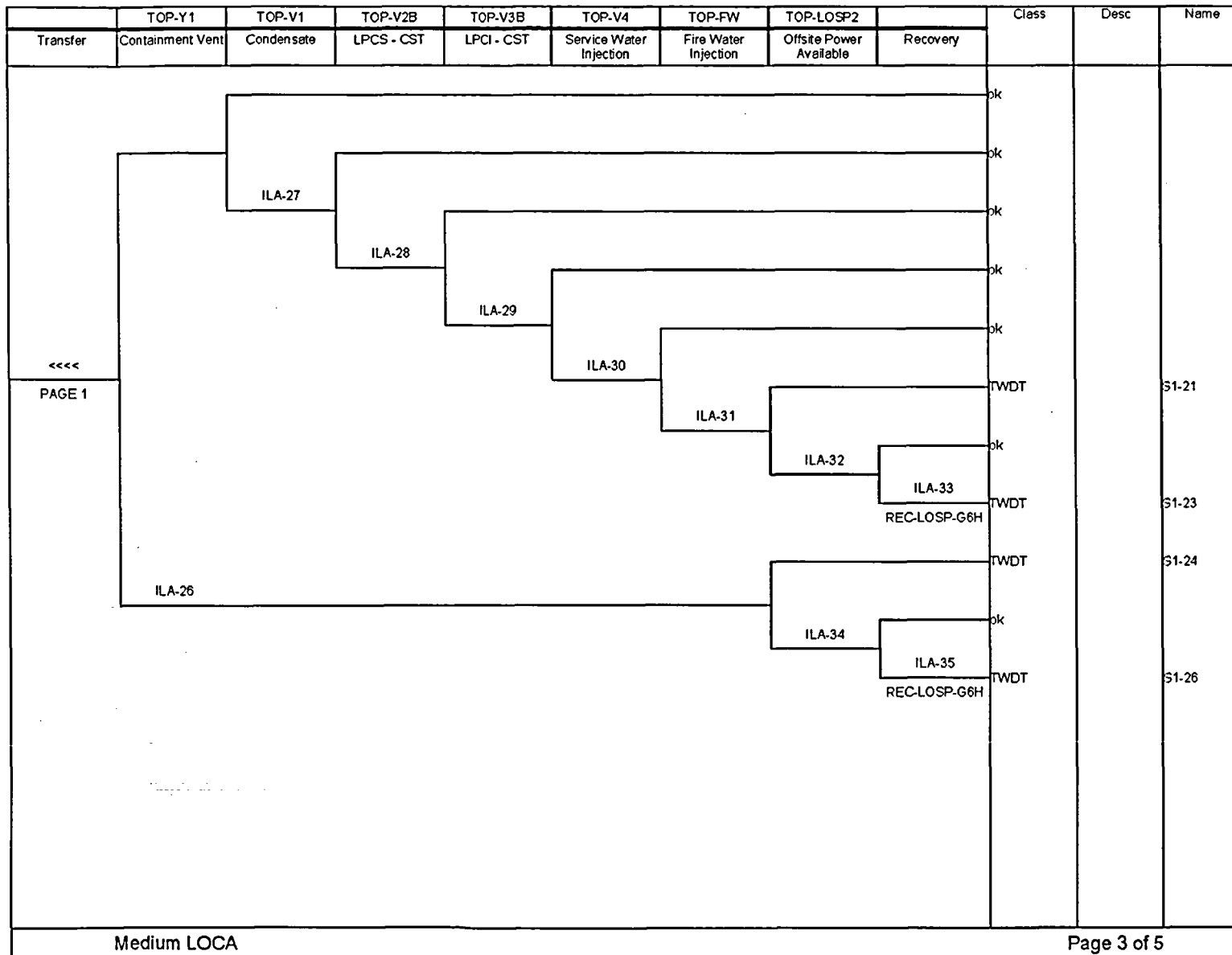


Figure C.3-5 Medium LOCA Event Tree (Continue)

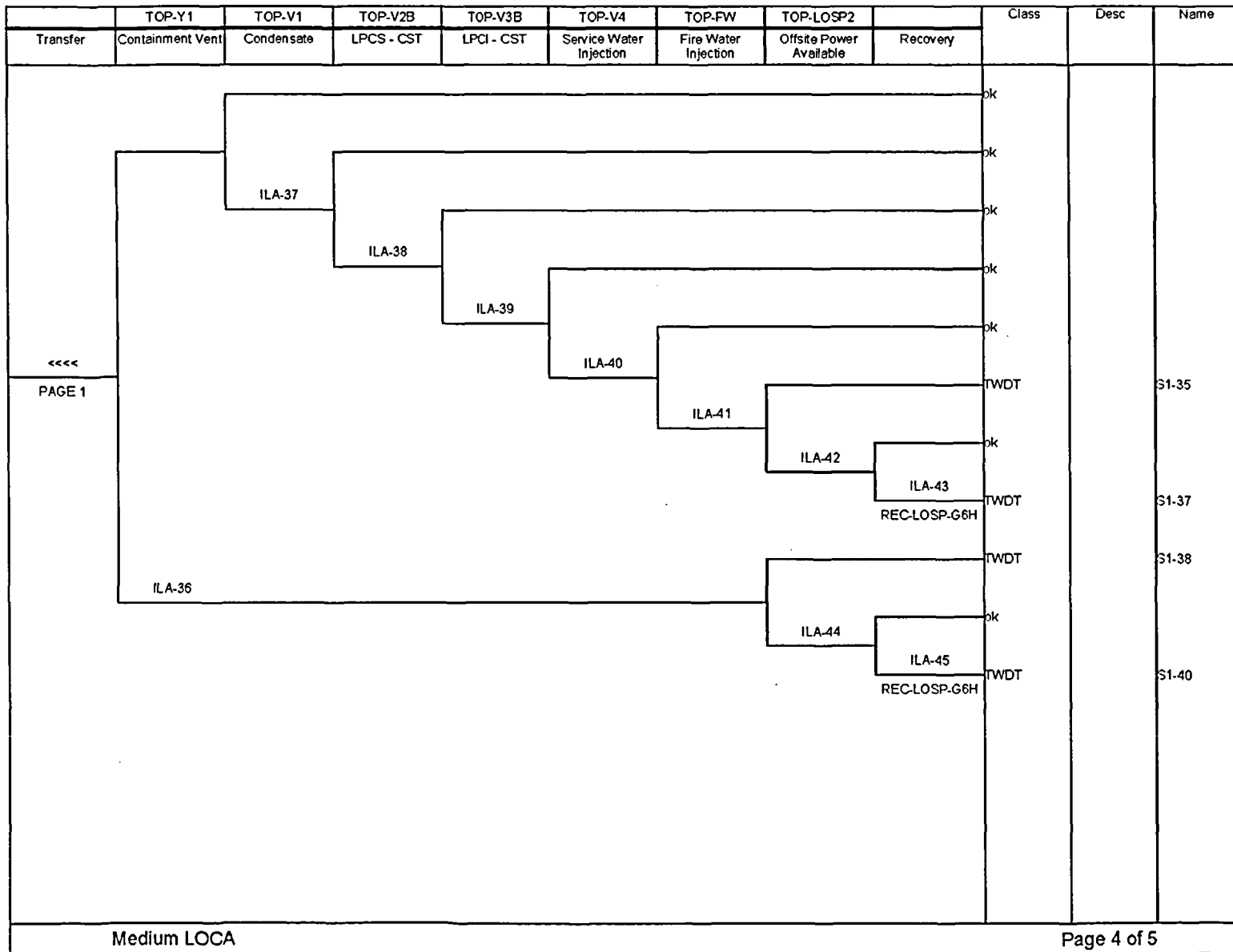


Figure C.3-5 Medium LOCA Event Tree (Continue)

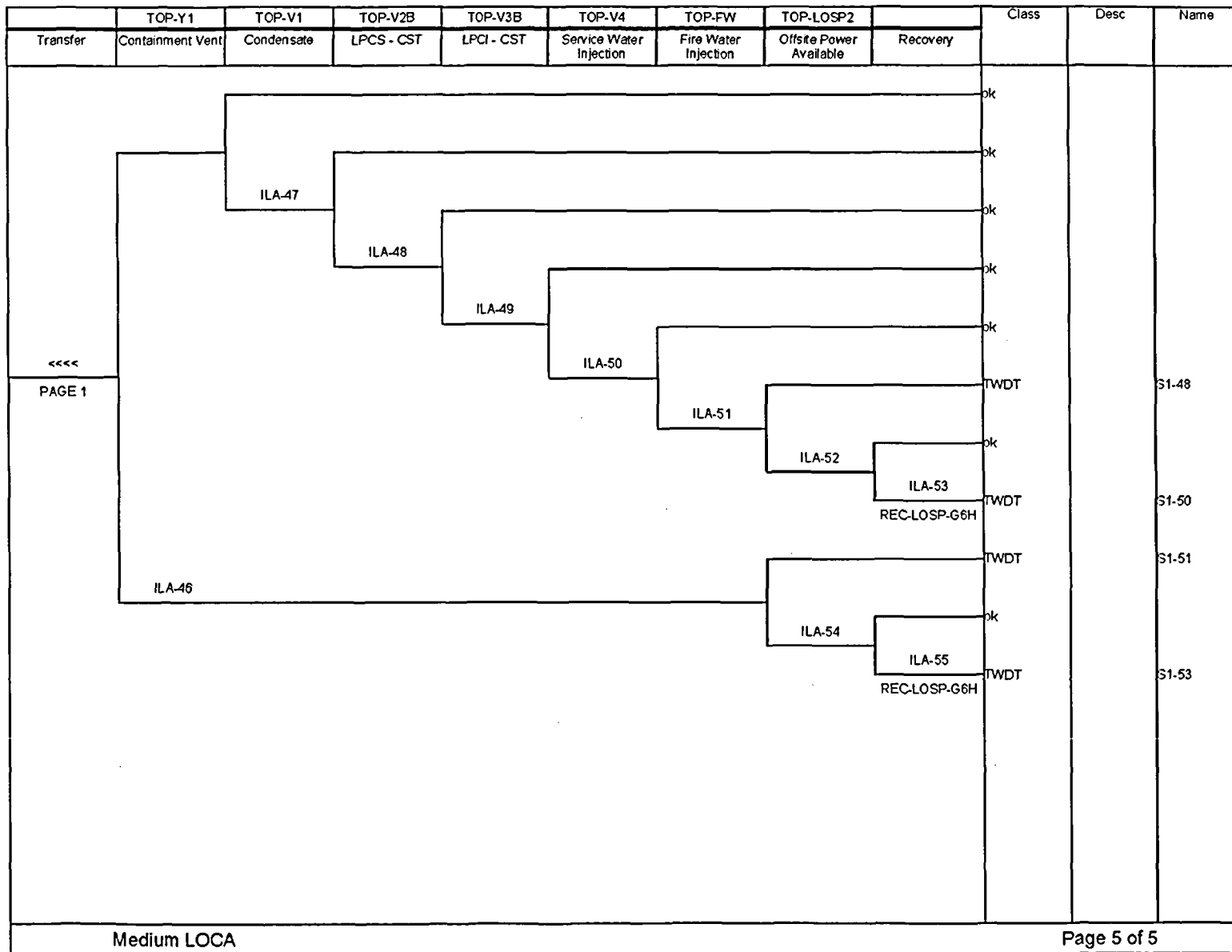


Figure C.3-5 Medium LOCA Event Tree (Continue)

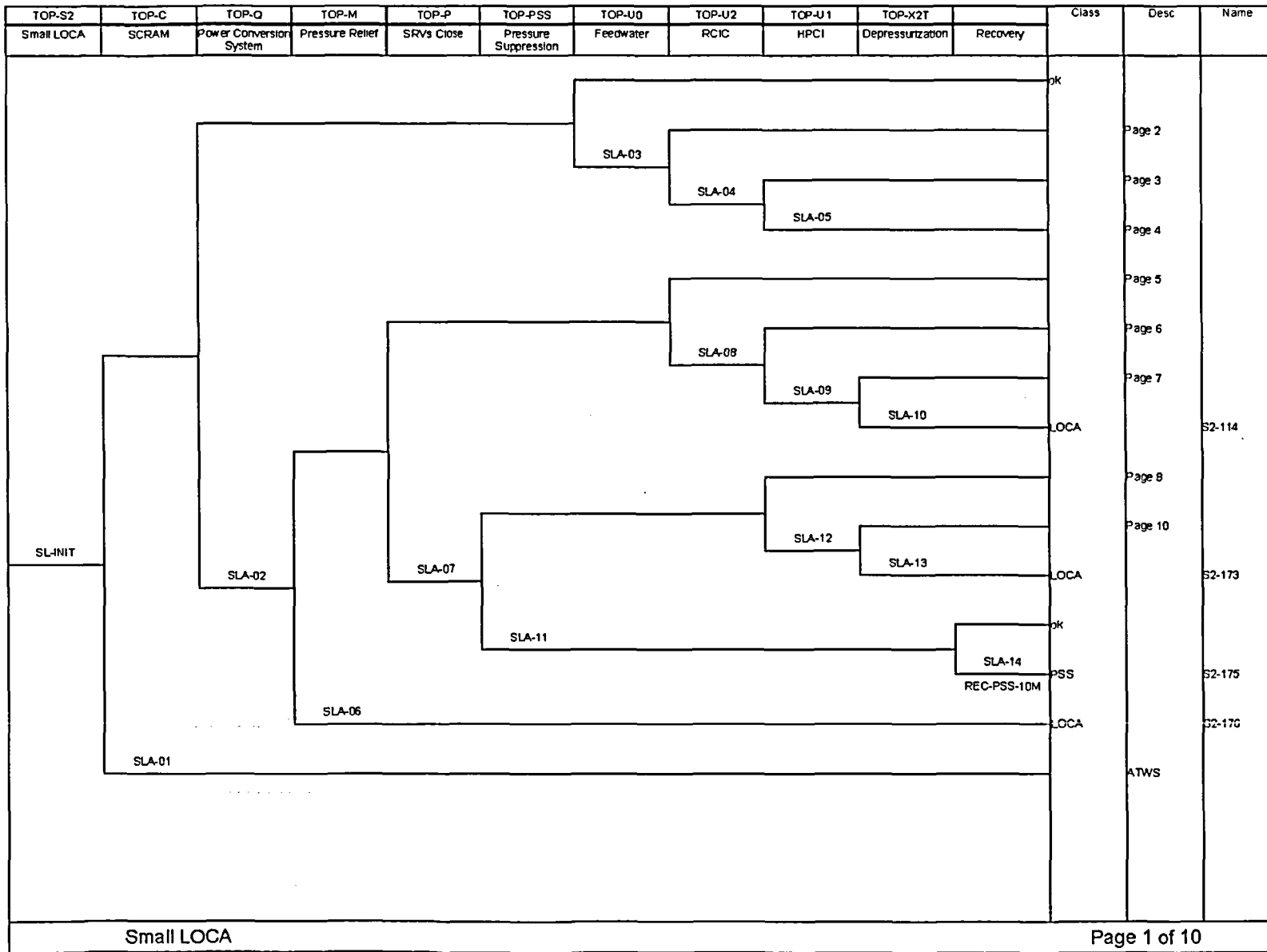


Figure C.3-6 Small LOCA

C.8-68

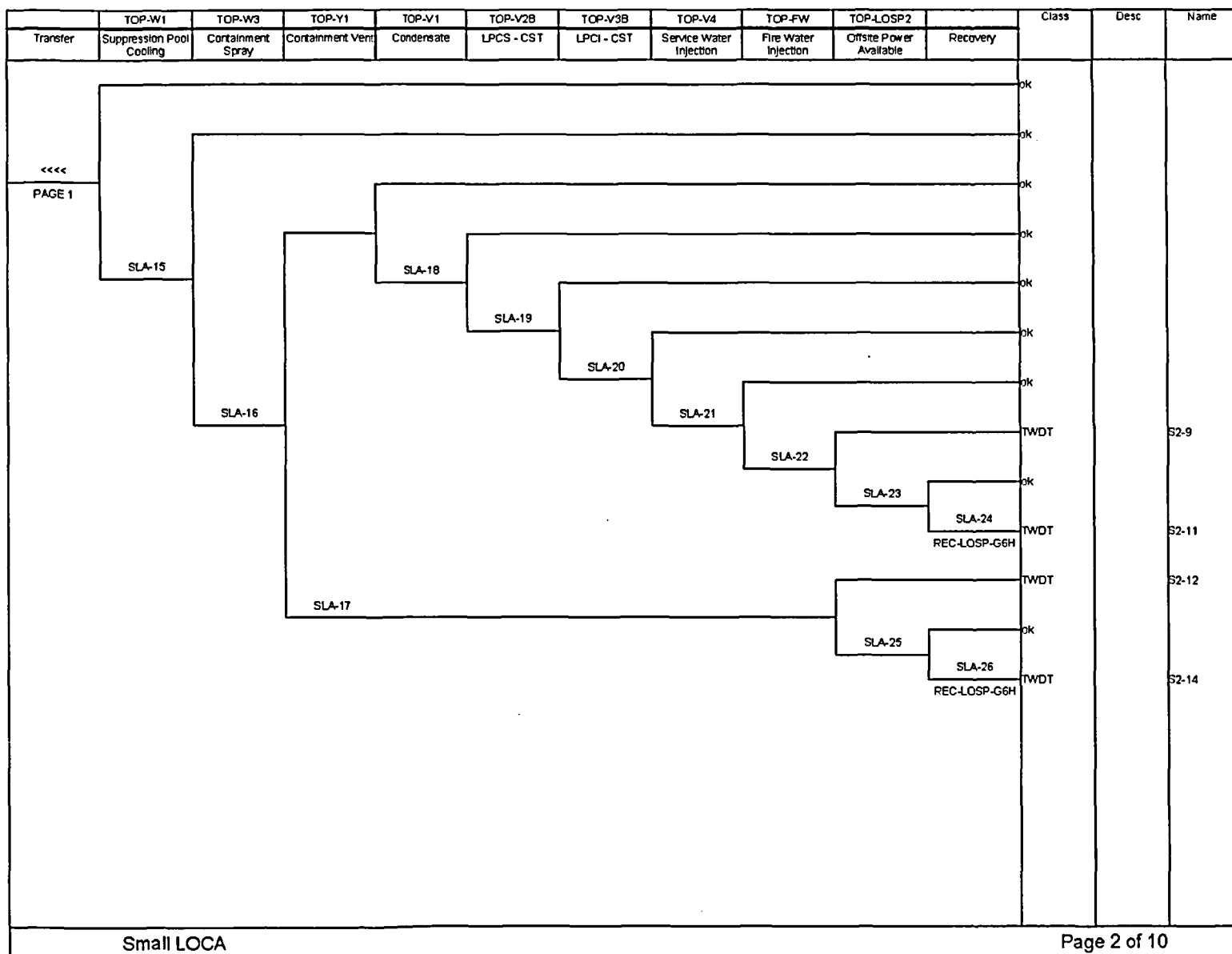


Figure C.3-6 Small LOCA (Continue)

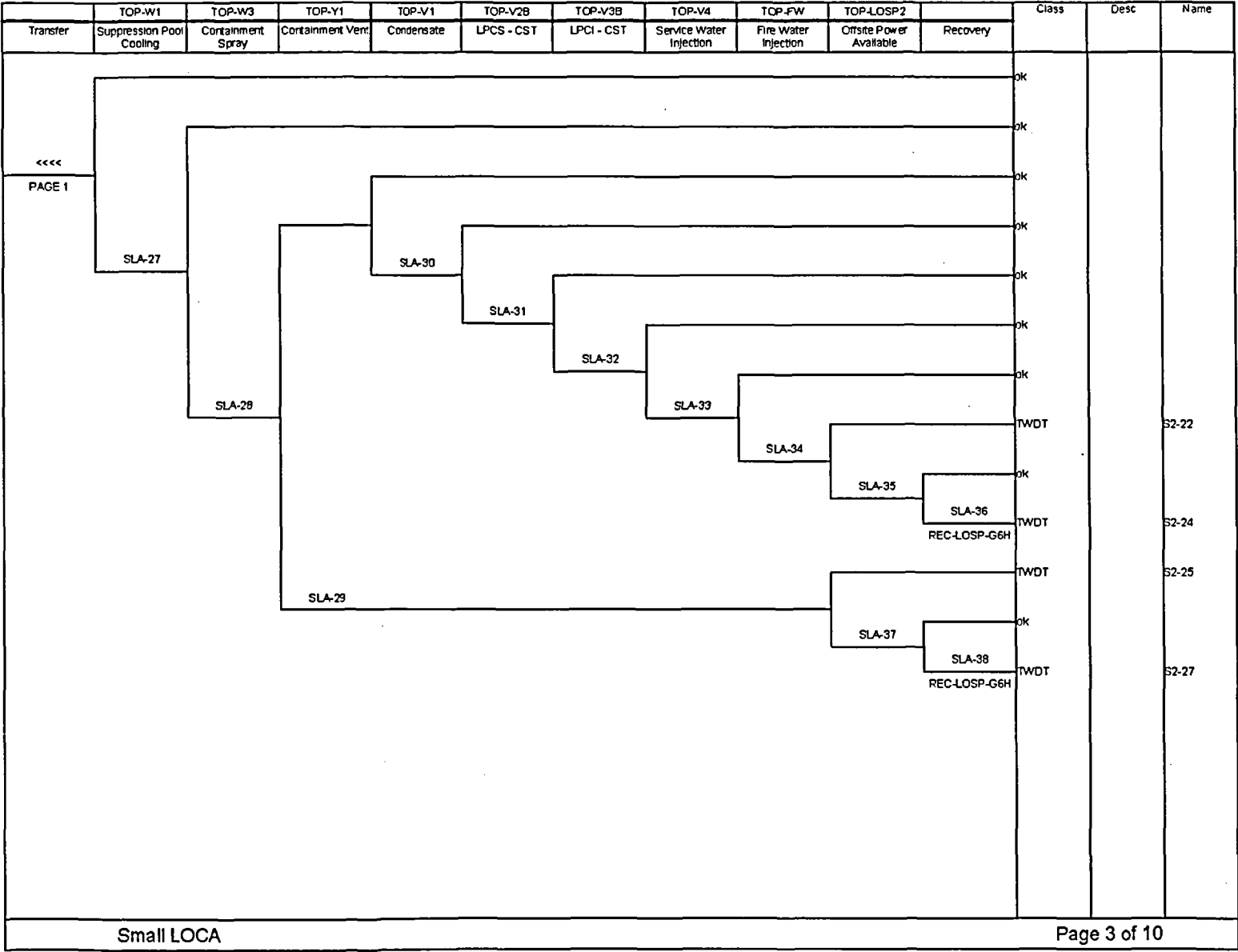


Figure C.3-6 Small LOCA (Continue)

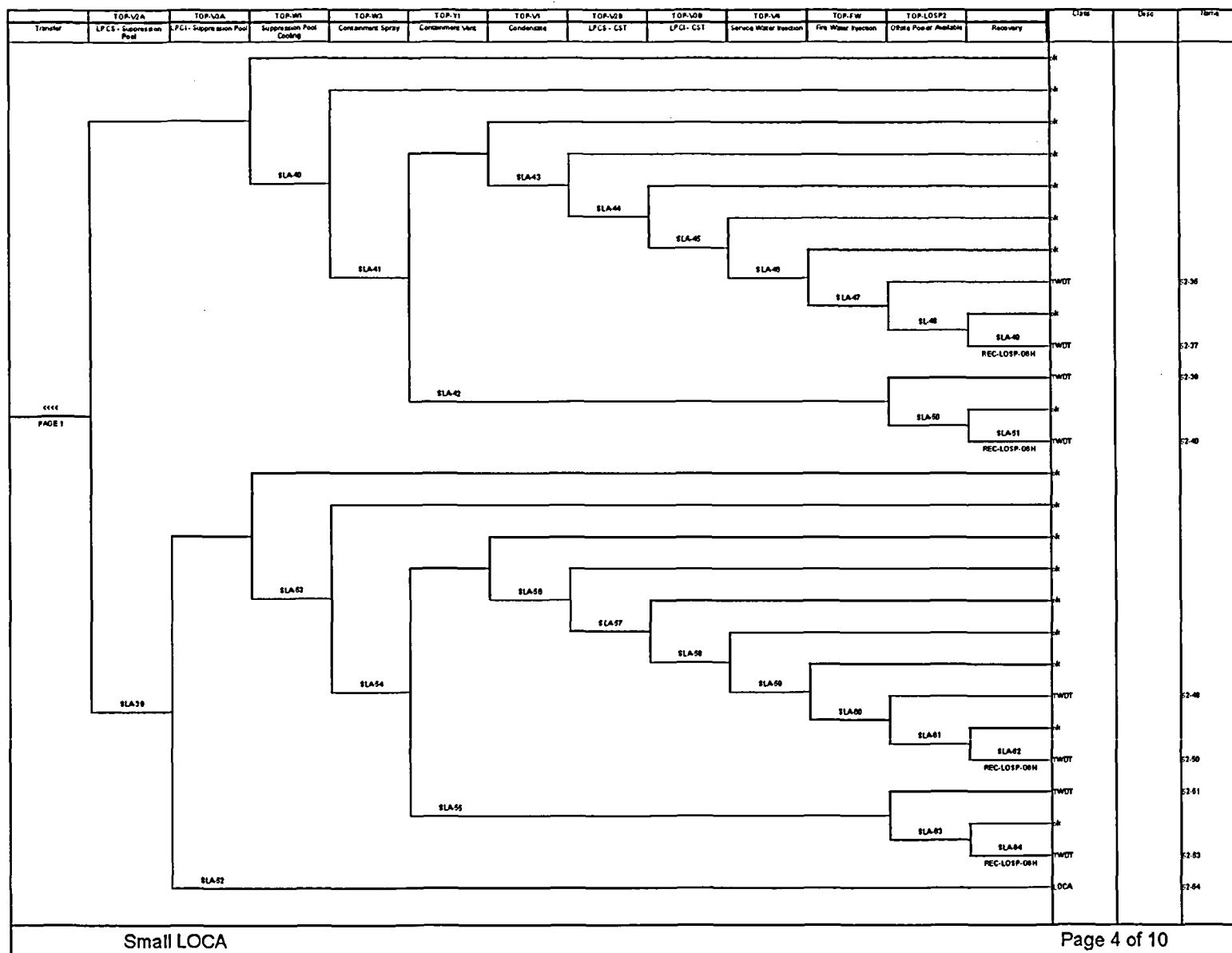


Figure C.3-6 Small LOCA (Continue)

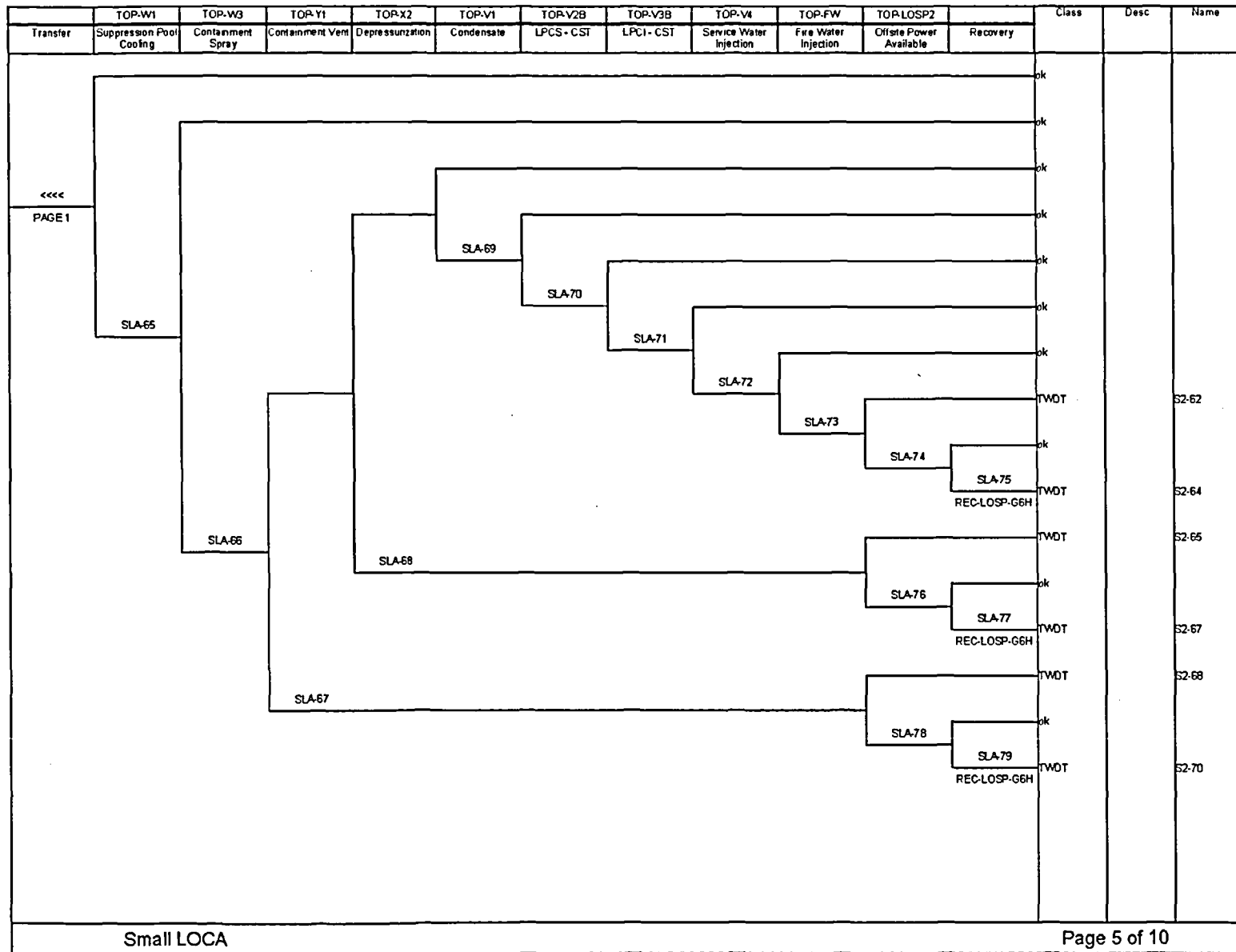
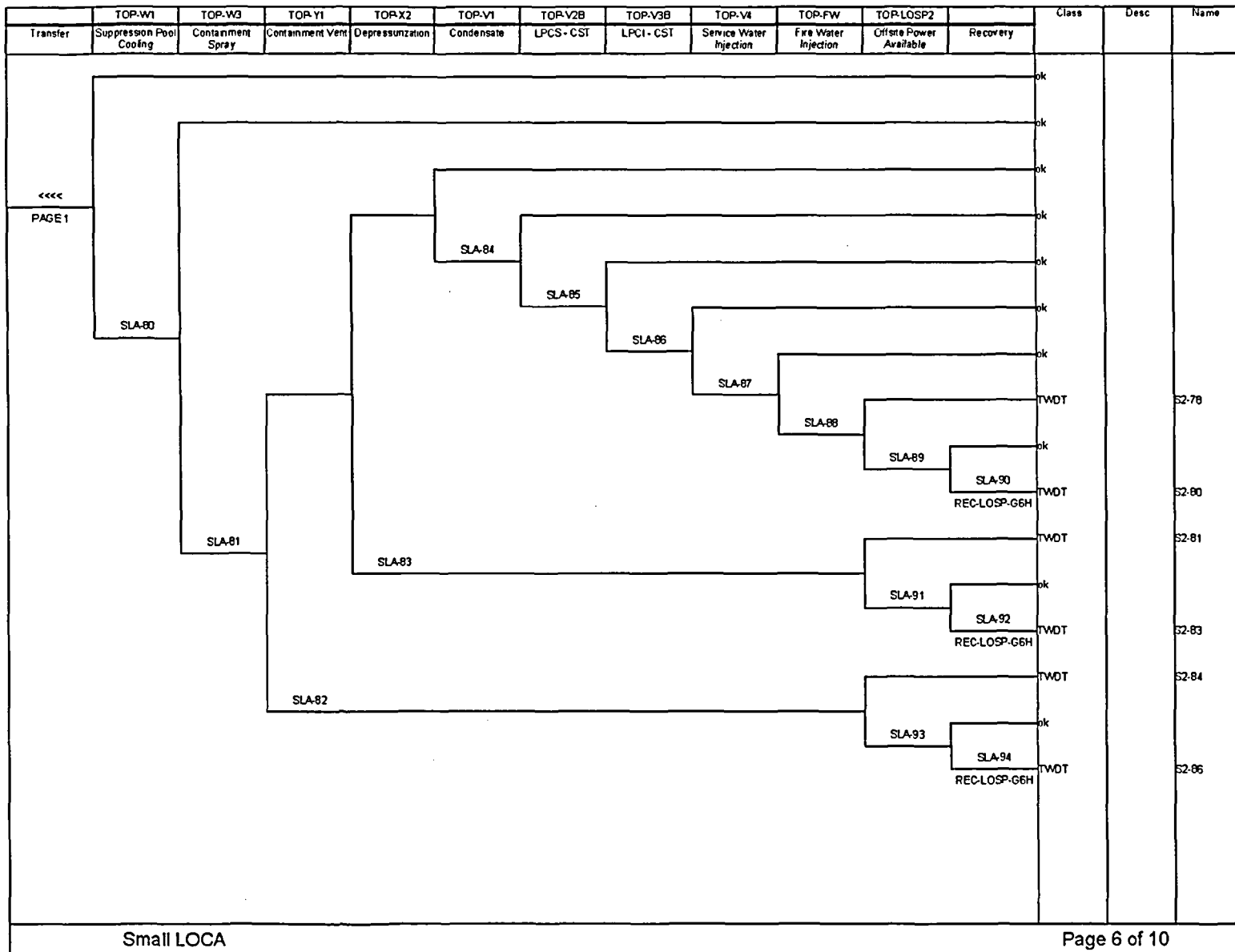
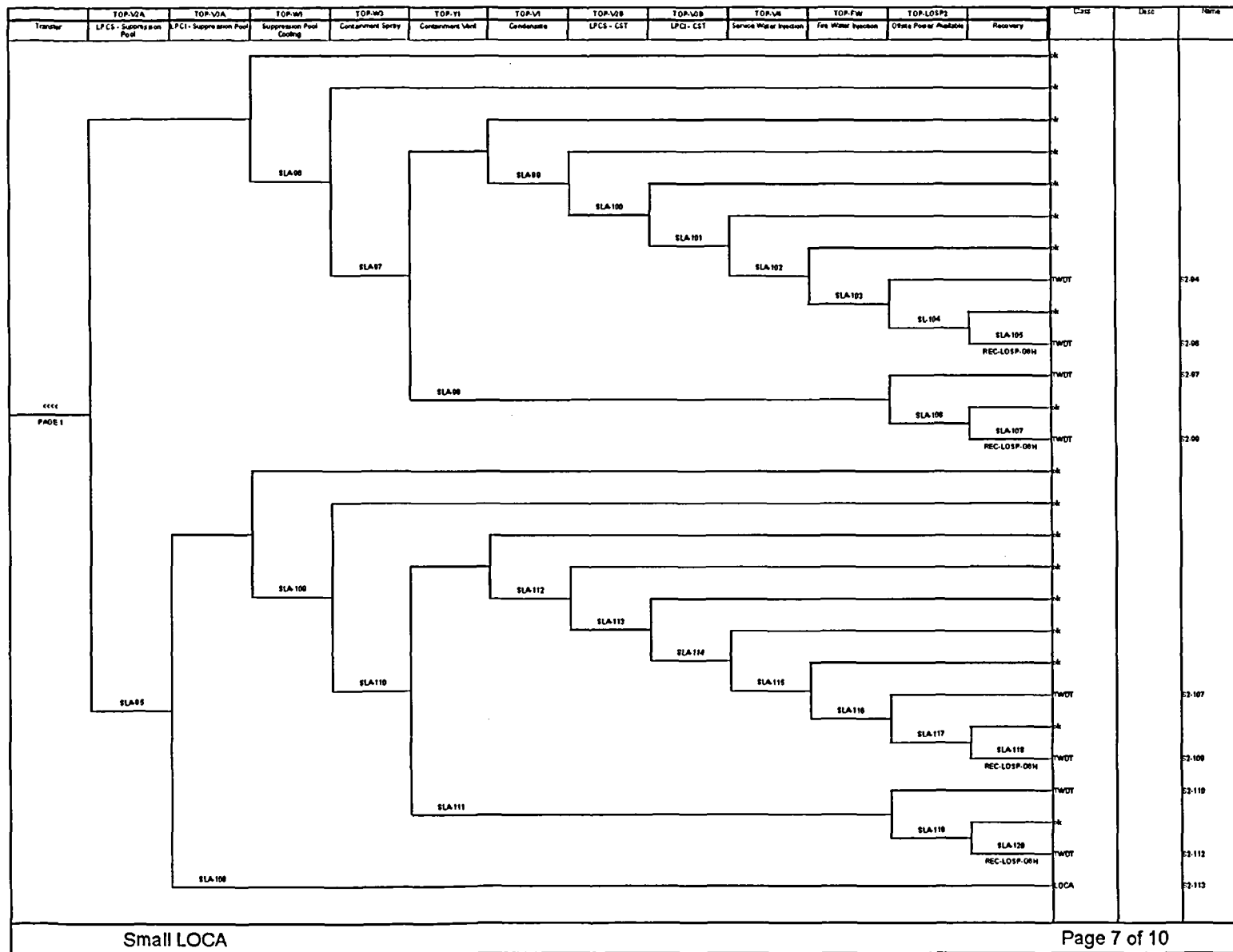


Figure C.3-6 Small LOCA (Continue)







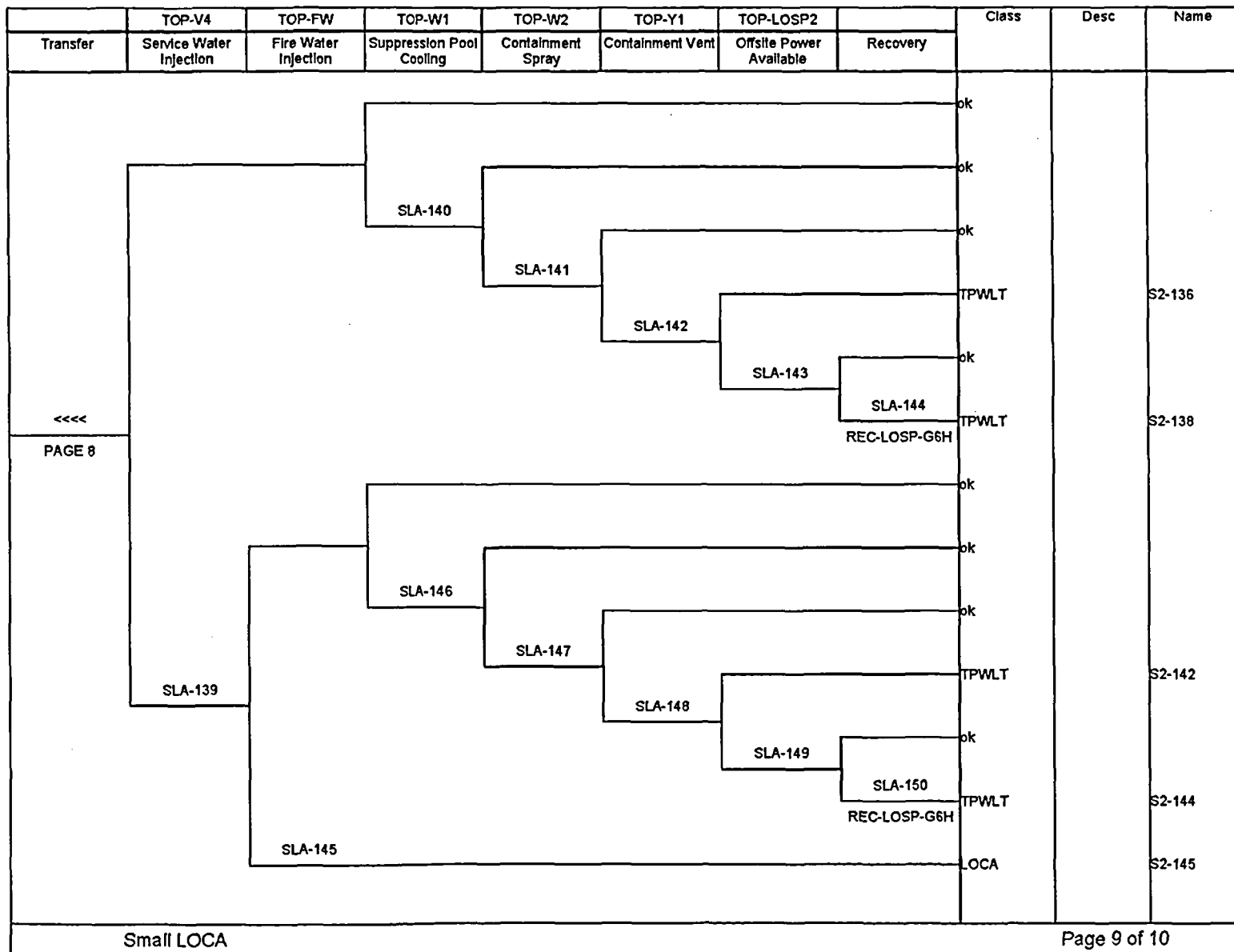


Figure C.3-6 Small LOCA (Continue)

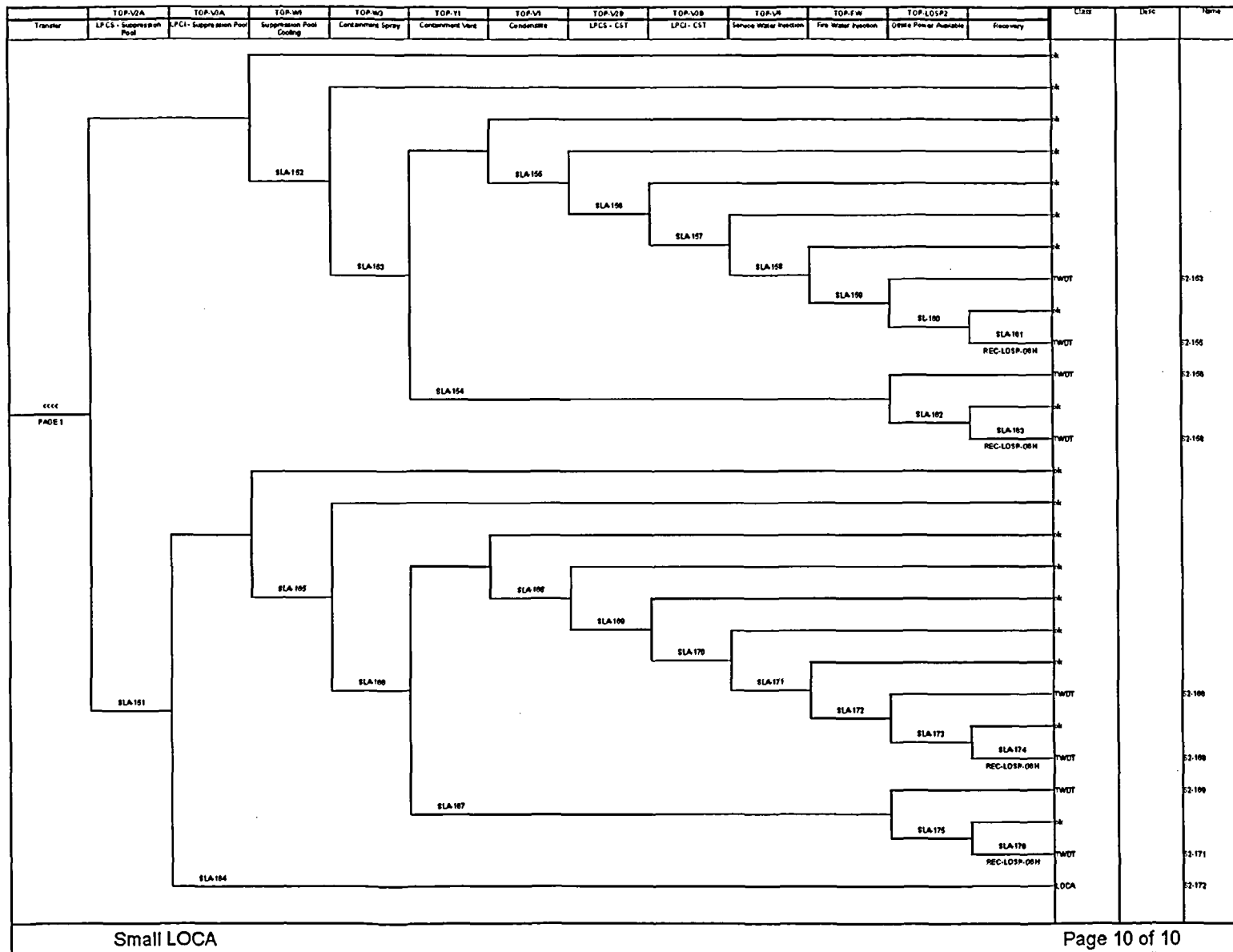


Figure C.3-6 Small LOCA (Continue)

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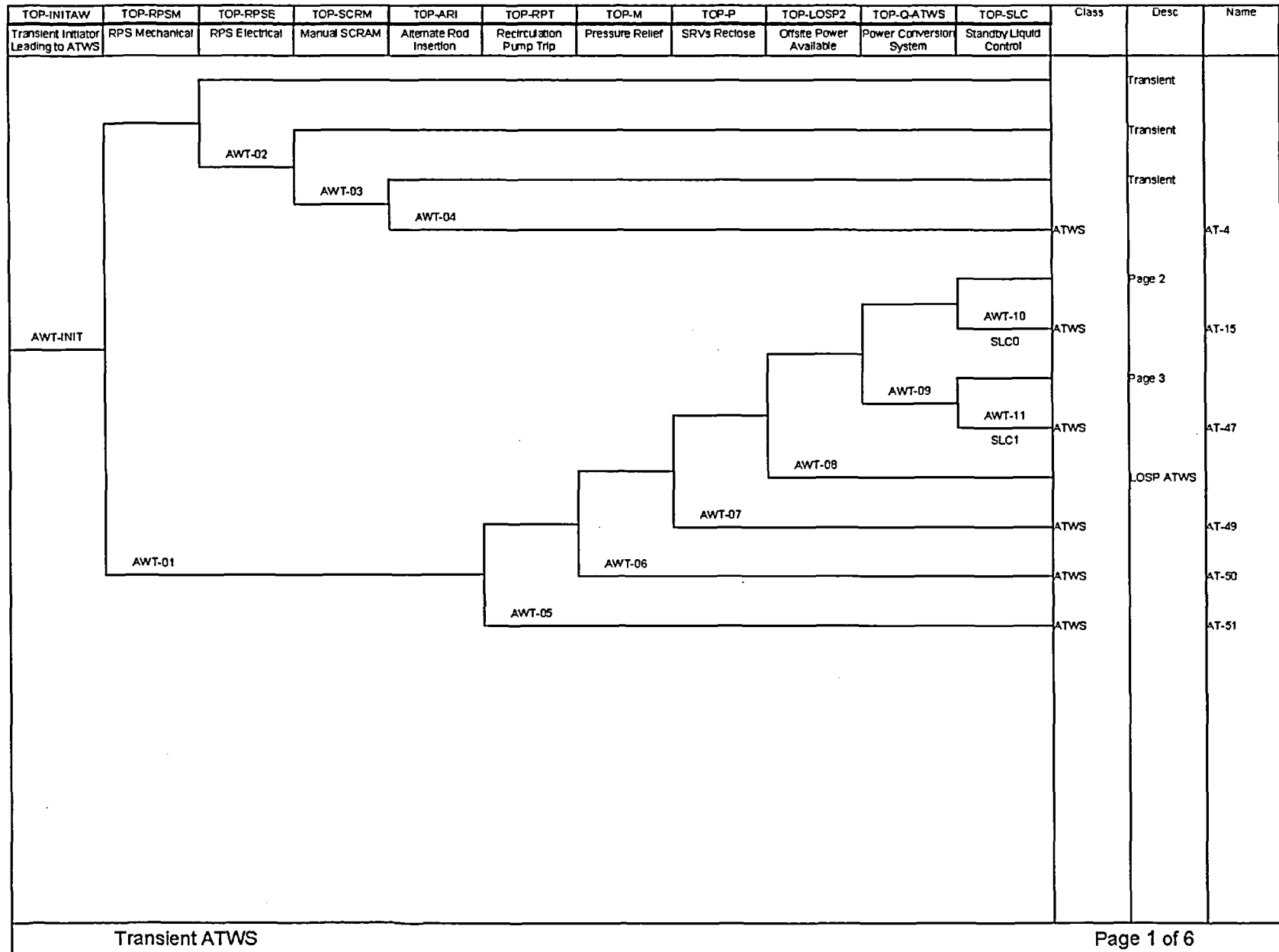


Figure C.3-7 ATWS Following a Transient Event Tree

	TOP-U0	TOP-U1	TOP-NX	TOP-X2B	TOP-LVL	Class	Desc	Name
Transfer	Feedwater	HPCI	Inhibit ADS	Depressurization	Level Control			
<div><div><div><div><div></div><div>AWT-12</div></div><div><div><div><div><div></div><div>AWT-13</div><div>NX1</div></div><div><div><div><div><div></div><div>AWT-14</div><div>LVL2</div></div><div><div><div><div><div></div><div>AWT-17</div><div>LVL2</div></div><div><div><div><div><div></div><div>AWT-16</div><div>NX2</div></div><div><div><div><div><div></div><div>AWT-15</div></div><div><div><div><div><div></div><div>AWT-18</div><div>NX3</div></div><div><div><div><div><div></div><div>AWT-19</div><div>LVL2</div></div><div><div><div><div><div></div><div>AWT-20</div><div>LVL2</div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div></div> </								

Figure C.3-7 ATWS Following a Transient Event Tree (Continue)

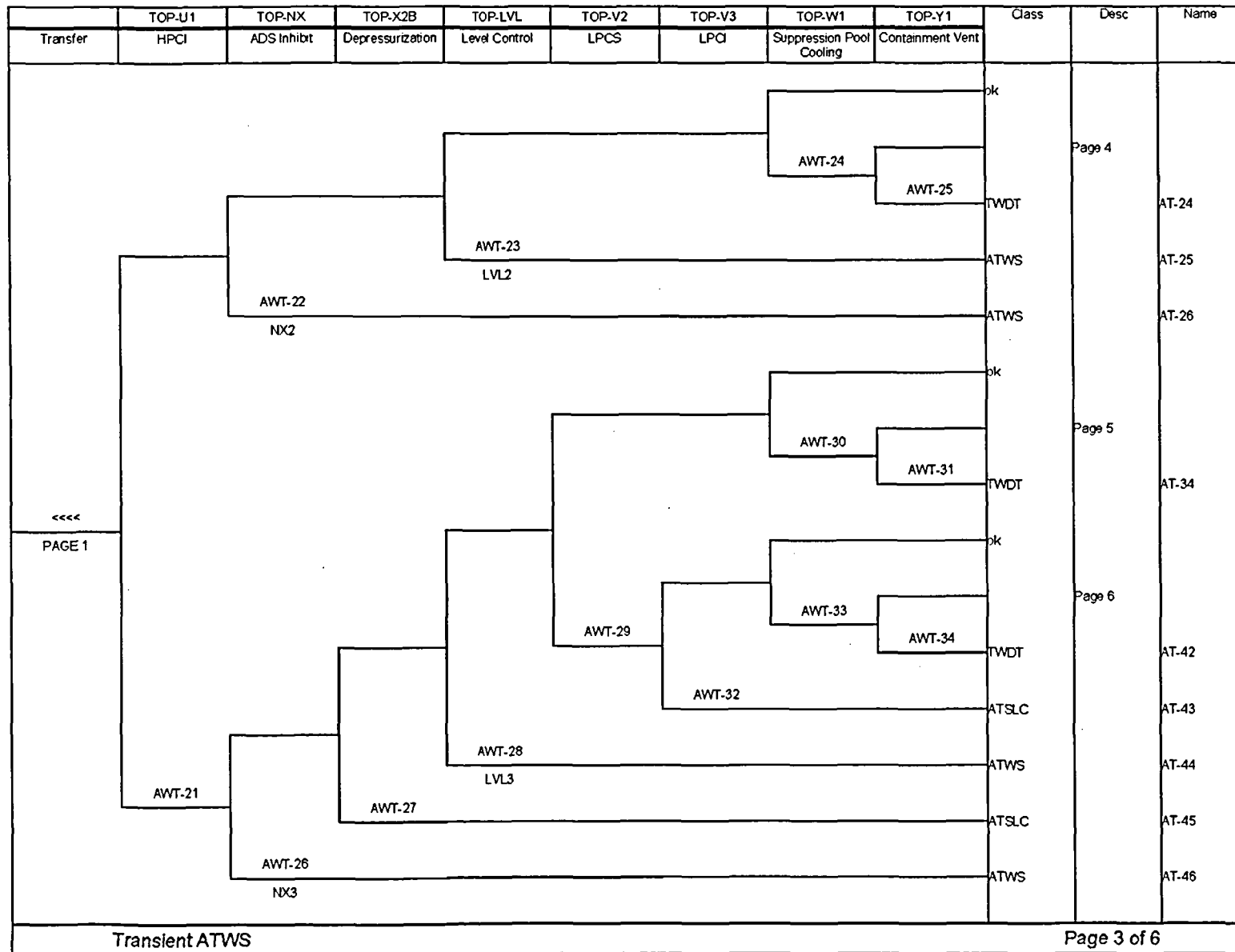
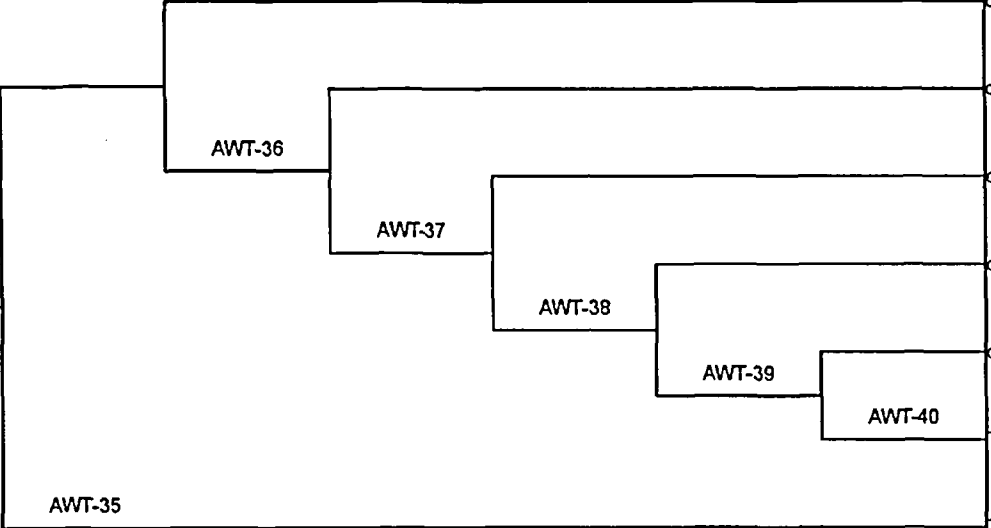


Figure C.3-7 ATWS Following a Transient Event Tree (Continue)

	TOP-X2A	TOP-V1	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW	Class	Desc	Name
Transfer	Depressurization	Condensate	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection			
							ok		
							ok		
							ok		
							ok		
							ok		
							ok		
							TWDT		AT-22
							TWDT		AT-23

Transient ATWS
Page 4 of 6

Figure C.3-7 ATWS Following a Transient Event Tree (Continue)

	TOP-V1	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW	Class	Desc	Name
Transfer	Condensate	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection			
<<<<						ok		
PAGE 3						ok		
	AWT-41					ok		
		AWT-42				ok		
			AWT-43			ok		
				AWT-44		ok		
					AWT-45	TWDT		AT-33
Transient ATWS						Page 5 of 6		

Figure C.3-7 ATWS Following a Transient Event Tree (Continue)

	TOP-V1	TOP-V2B	TOP-V3B	TOP-V4	TOP-FW	Class	Desc	Name
Transfer	Condensate	LPCS - CST	LPCI - CST	Service Water Injection	Fire Water Injection			
<<<<						ok		
PAGE 3						ok		
	AWT-46					ok		
		AWT-47				ok		
			AWT-48			ok		
				AWT-49		ok		
					AWT-50	TWDT		AT-41
Transient ATWS								

Page 6 of 6

Figure C.3-7 ATWS Following a Transient Event Tree (Continue)

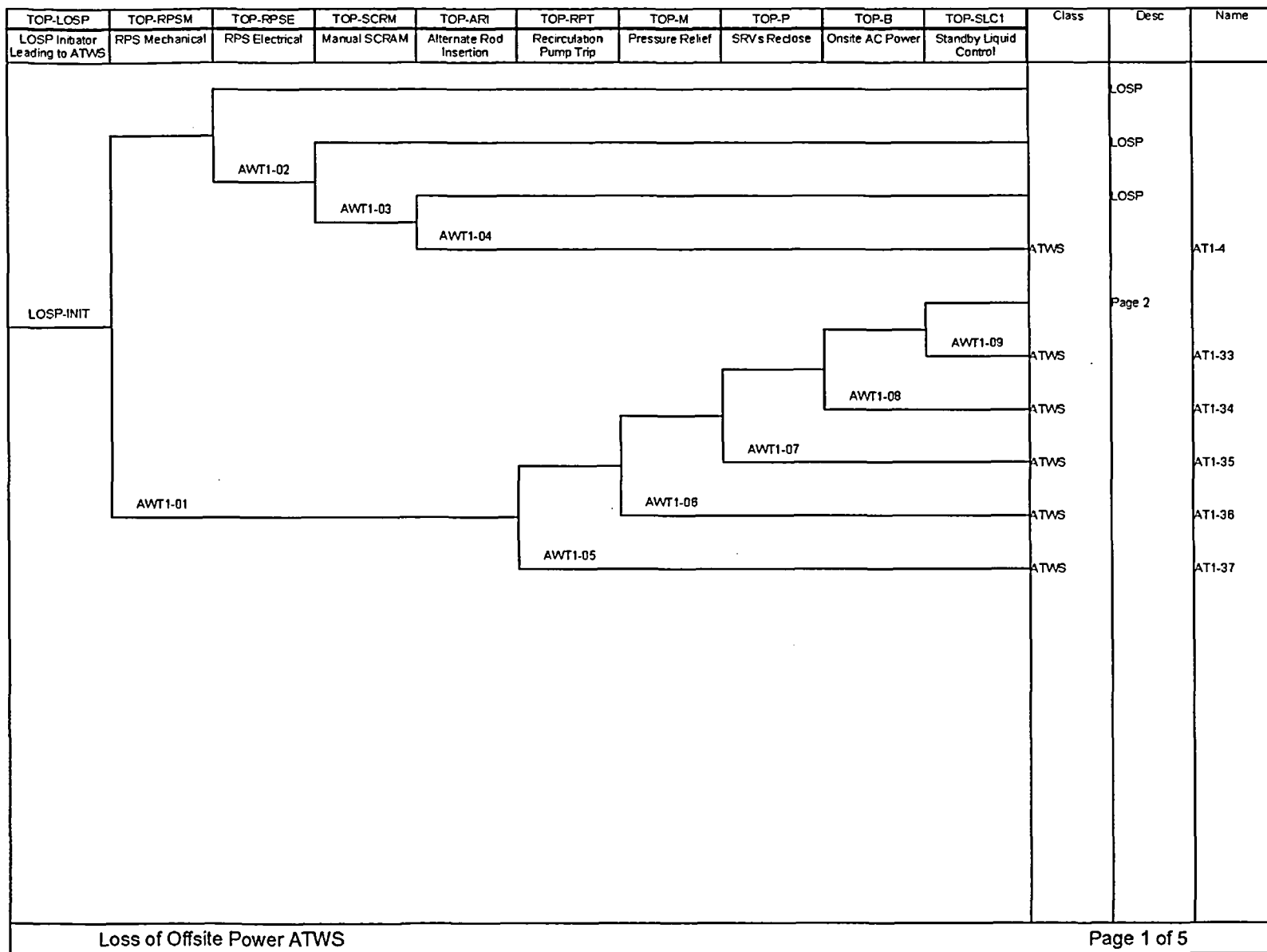


Figure C.3-8 ATWS Following a Loss of Offsite Power Event Tree

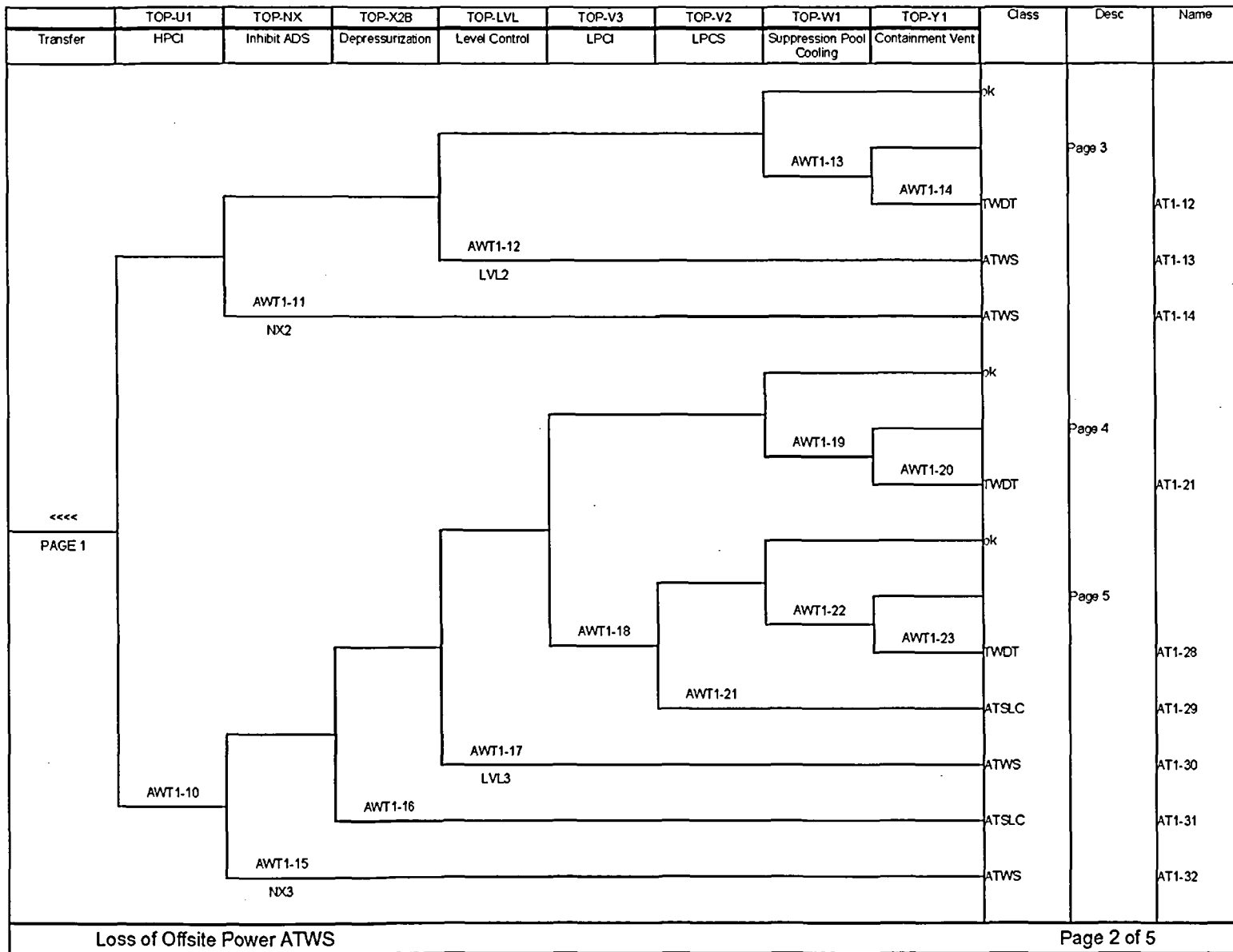


Figure C.3-8 ATWS Following a Loss of Offsite Power Event Tree (Continue)

	TOP-X2A	TOP-V3B	TOP-V2B	TOP-V4	TOP-FW	Class	Desc	Name
Transfer	Depressurization	LPCI - CST	LPCS - CST	Service Water Injection	Fire Water Injection			
<<<< PAGE 2	<pre>graph LR; AWT1-24 --- AWT1-25; AWT1-25 --- AWT1-26; AWT1-26 --- AWT1-27; AWT1-27 --- AWT1-28; AWT1-24 --- OK1(ok); AWT1-25 --- OK2(ok); AWT1-26 --- OK3(ok); AWT1-27 --- OK4(ok); AWT1-28 --- TWDT1(TWDT); AWT1-24 --- TWDT2(TWDT);</pre>					ok		
						ok		
						ok		
						ok		
						TWDT		AT1-10
						TWDT		AT1-11
Loss of Offsite Power ATWS						Page 3 of 5		

Figure C.3-8 ATWS Following a Loss of Offsite Power Event Tree (Continue)

	TOP-V3B	TOP-V2B	TOP-V4	TOP-FW	Class	Desc	Name
Transfer	LPCI - CST	LPCS - CST	Service Water Injection	Fire Water Injection			
<div><div><<<<</div><div>PAGE 2</div><div><div>AWT1-29</div><div>AWT1-30</div><div>AWT1-31</div><div>AWT1-32</div></div></div>					ok		AT1-20
					ok		
					ok		
					ok		
					TWDT		
Loss of Offsite Power ATWS							
Page 4 of 5							

Figure C.3-8 ATWS Following a Loss of Offsite Power Event Tree (Continue)

	TOP-V3B	TOP-V2B	TOP-V4	TOP-FW	Class	Desc	Name
Transfer	LPCI - CST	LPCS - CST	Service Water Injection	Fire Water Injection			
<div><div><<<<</div><div><div>PAGE 2</div><div><div>AWT1-33</div><div><div>AWT1-34</div><div><div>AWT1-35</div><div><div>AWT1-36</div></div></div></div></div></div></div>					ok		
					ok		
					ok		
					ok		
					TWDT		AT1-27
Loss of Offsite Power ATWS					Page 5 of 5		

Figure C.3-8 ATWS Following a Loss of Offsite Power Event Tree (Continue)

TOP-MEDLARGE	TOP-RPSM	TOP-RPSE	TOP-SCRM	TOP-ARI	Class	Desc	Name
Large or Medium LOCA	RPS Mechanical	RPS Electrical	Manual SCRAM	Alternate Rod Insertion			
AWA-INIT					ATWS	LLOCA	AWA-4
						LLOCA	
	AWLL-02					LLOCA	
	AWLL-03						
	AWLL-04						
	AWLL-01				ATWS		AWA-5
LLOCA and MLOCA ATWS							

Page 1 of 1

Figure C.3-9 ATWS Following a Large or Medium LOCA Event Tree

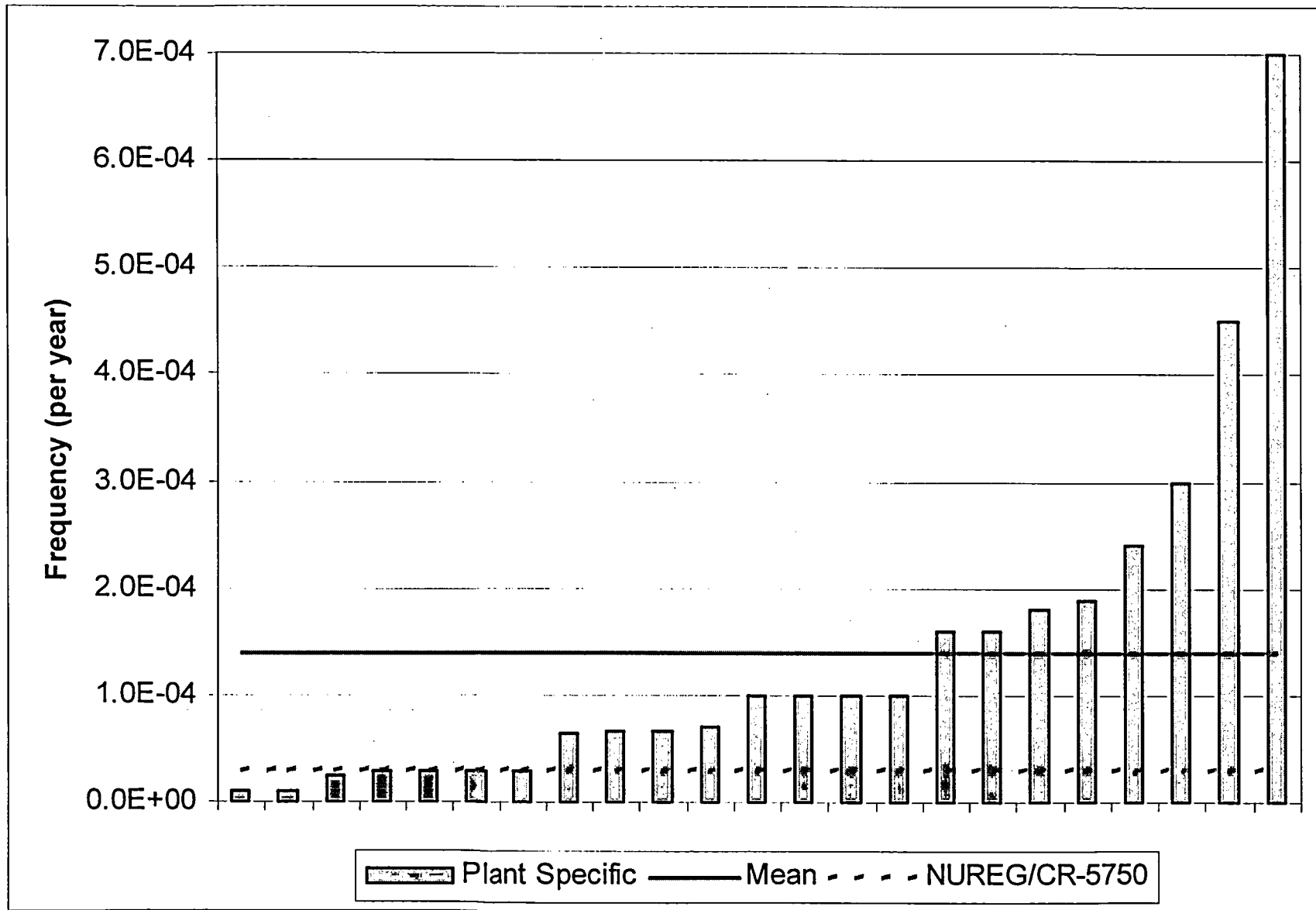


Figure C.3-10 Range of Plant-Specific LBLOCA Frequencies

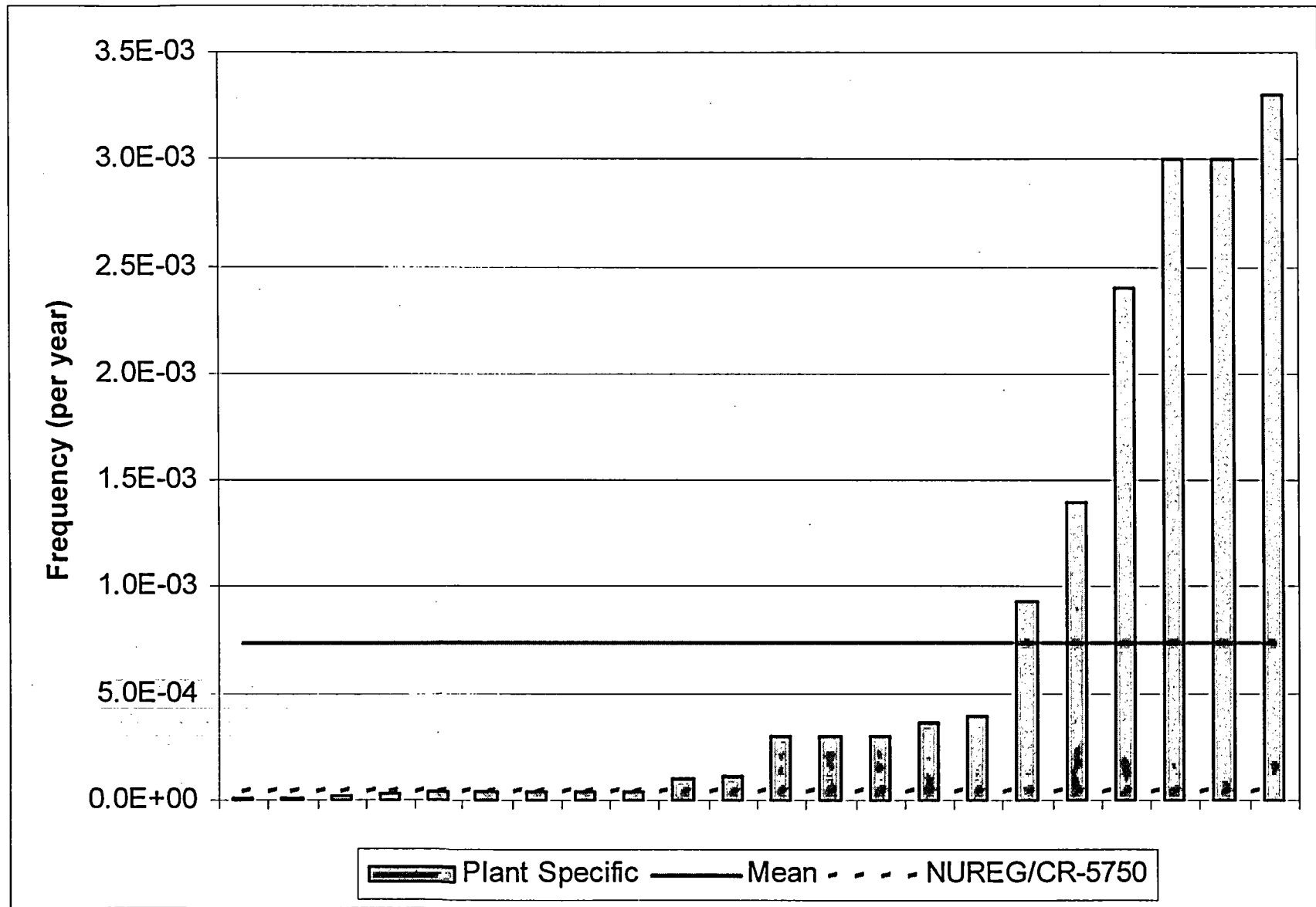


Figure C.3-11

Range of Plant-Specific MBLOCA Frequencies

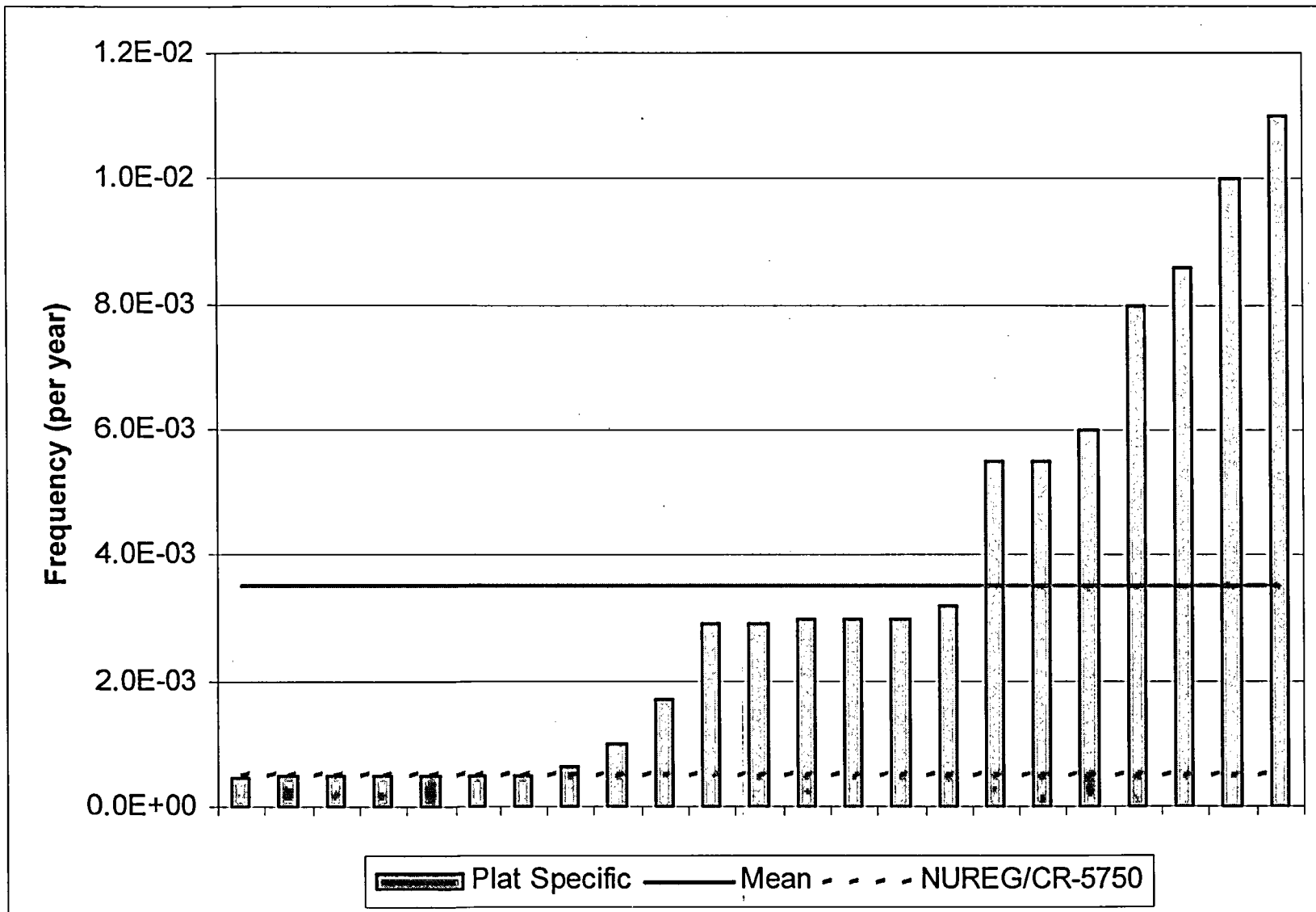


Figure C.3-12 Range of Plant-Specific SBLOCA Frequencies

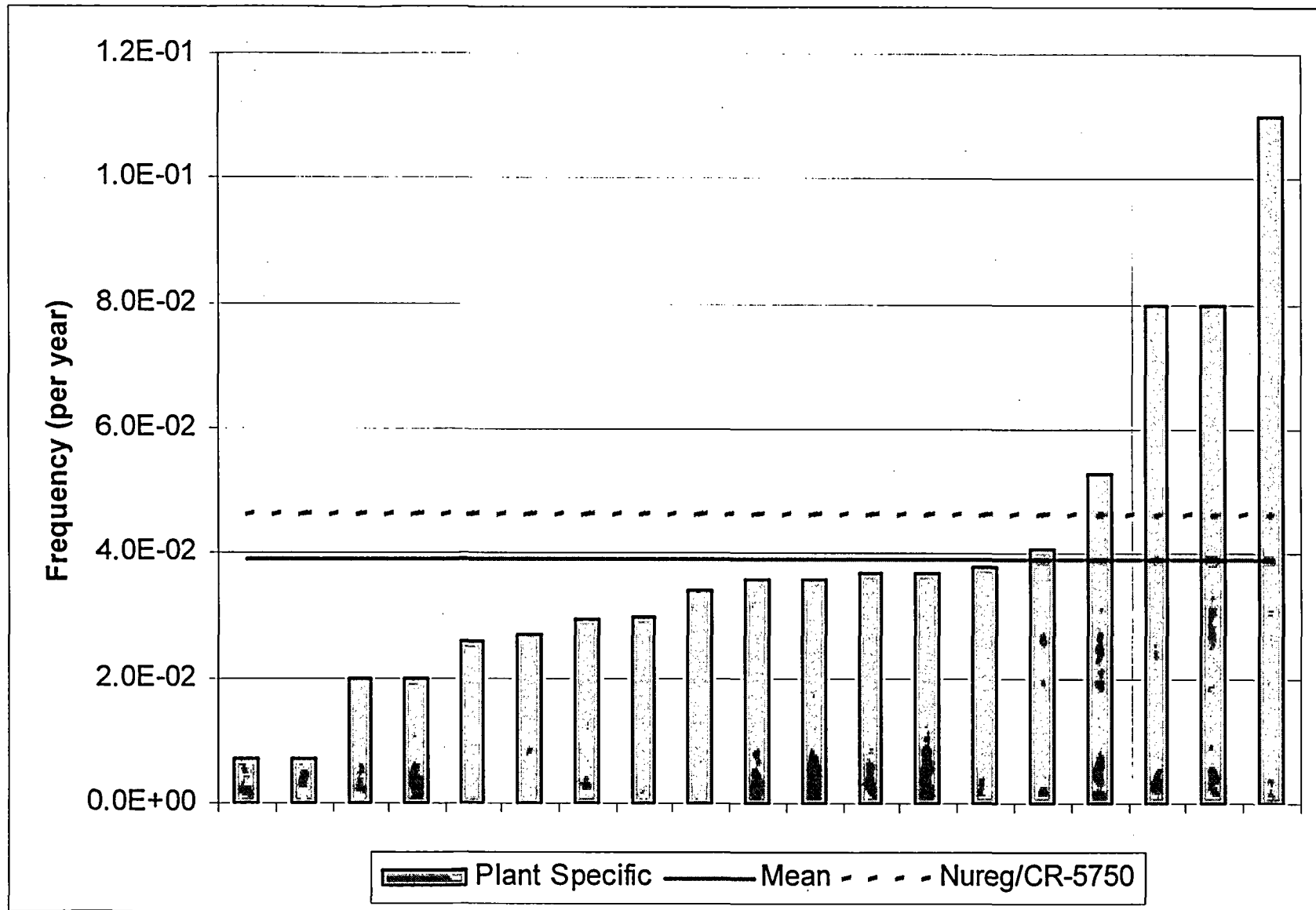


Figure C.3-13

Range of Plant-Specific LOOP Frequencies

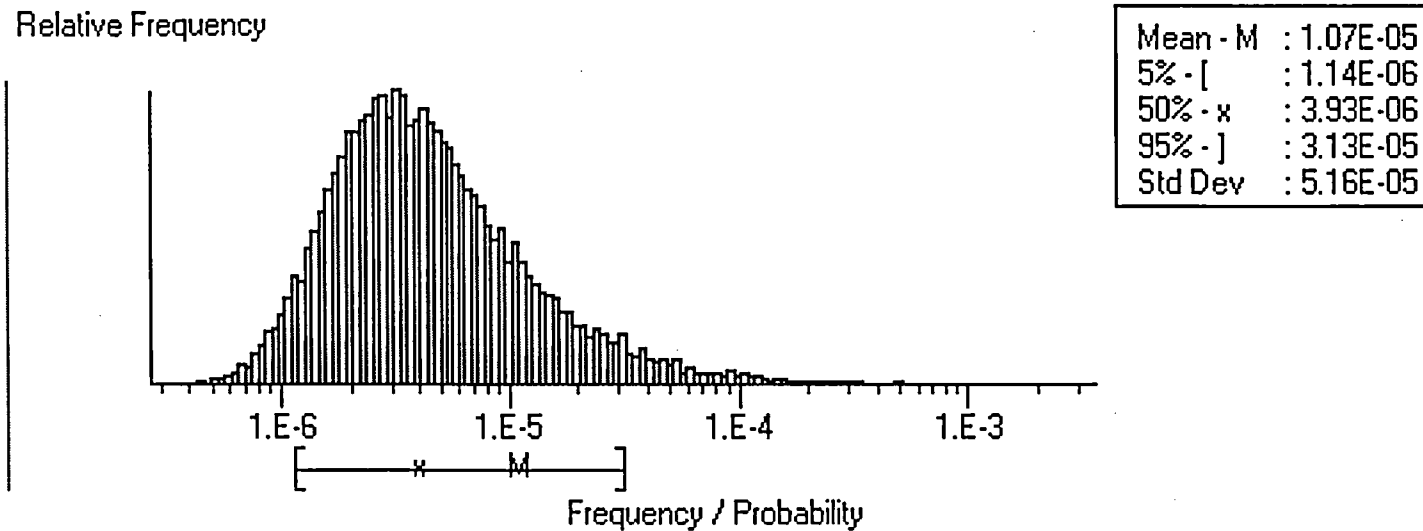


Figure C.3-14 **Distribution for BWR 4, No AC Independent Injection, No Independent AC Power**

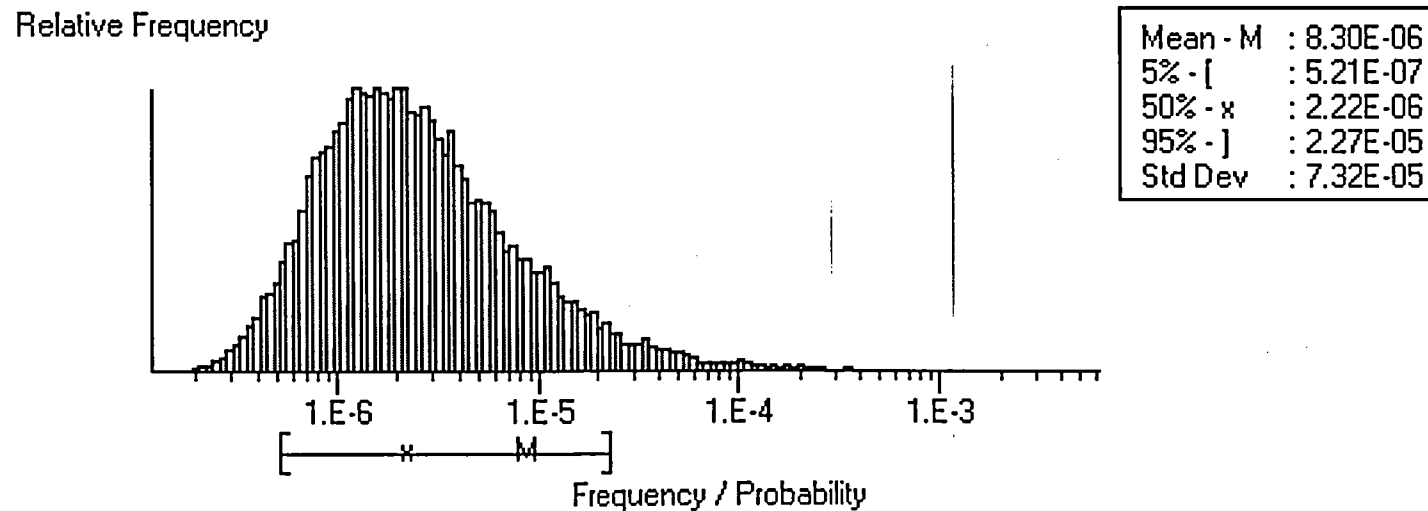
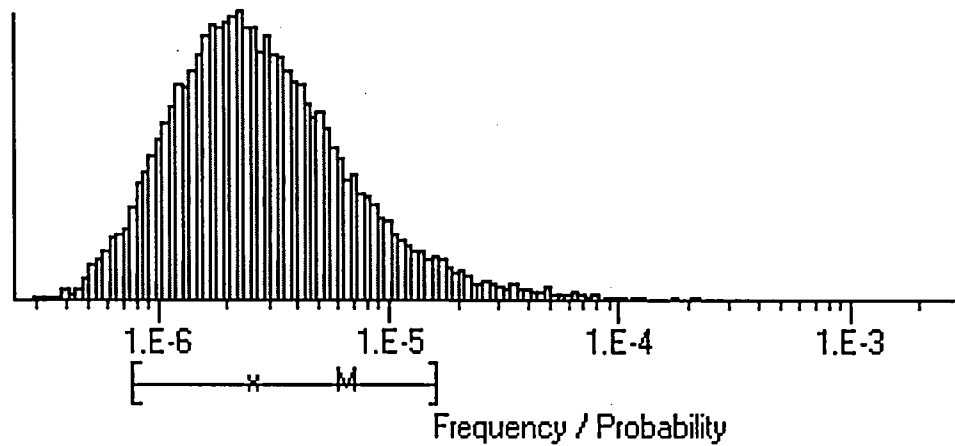


Figure C.3-15 **Distribution for BWR 4, With AC Independent Injection, No Independent AC Power**

Relative Frequency

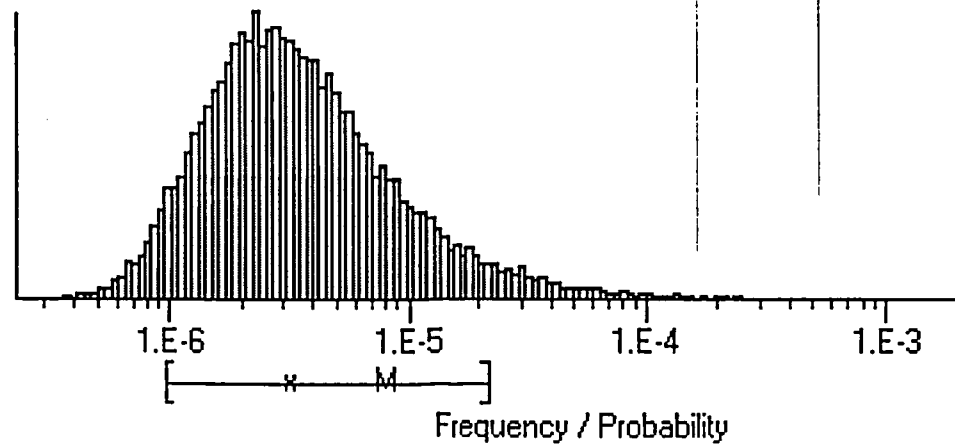


Mean - M	: 6.24E-06
5% - [: 7.66E-07
50% - x	: 2.56E-06
95% -]	: 1.59E-05
Std Dev	: 3.86E-05

Figure C.3-16

Distribution for BWR 4, With Independent AC Power

Relative Frequency



Mean - M	: 7.76E-06
5% - [: 9.58E-07
50% - x	: 3.17E-06
95% -]	: 2.21E-05
Std Dev	: 3.30E-05

Figure C.3-17

Distribution for BWR 6, No AC Independent Injection, No Independent AC Power

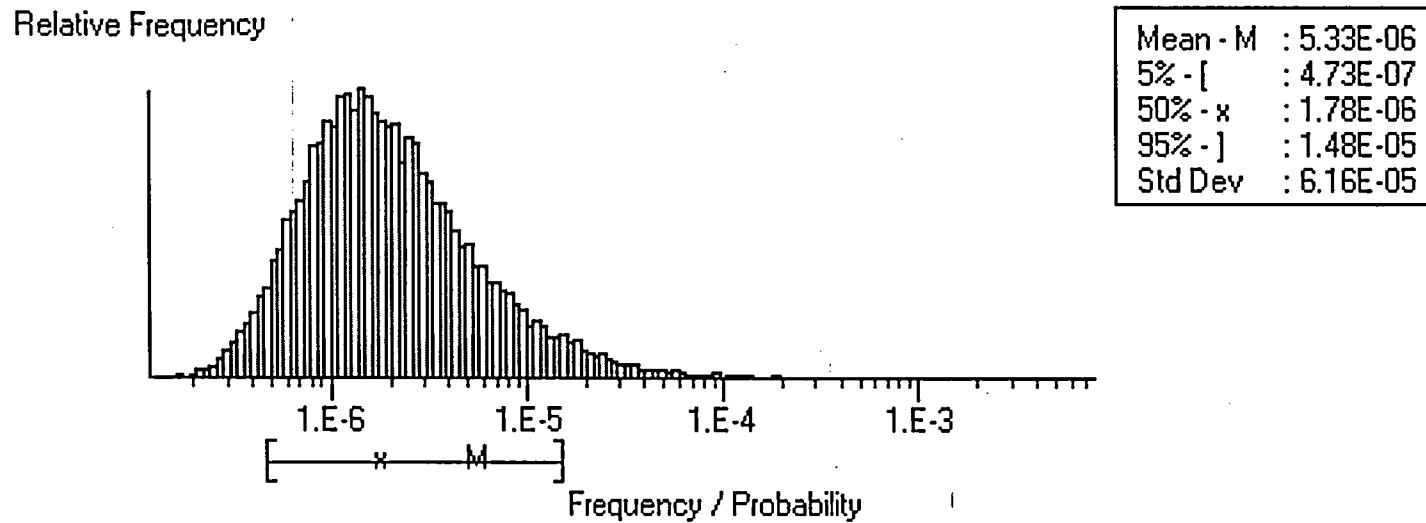


Figure C.3-18 **Distribution for BWR 6, With AC Independent Injection, No Independent AC Power**

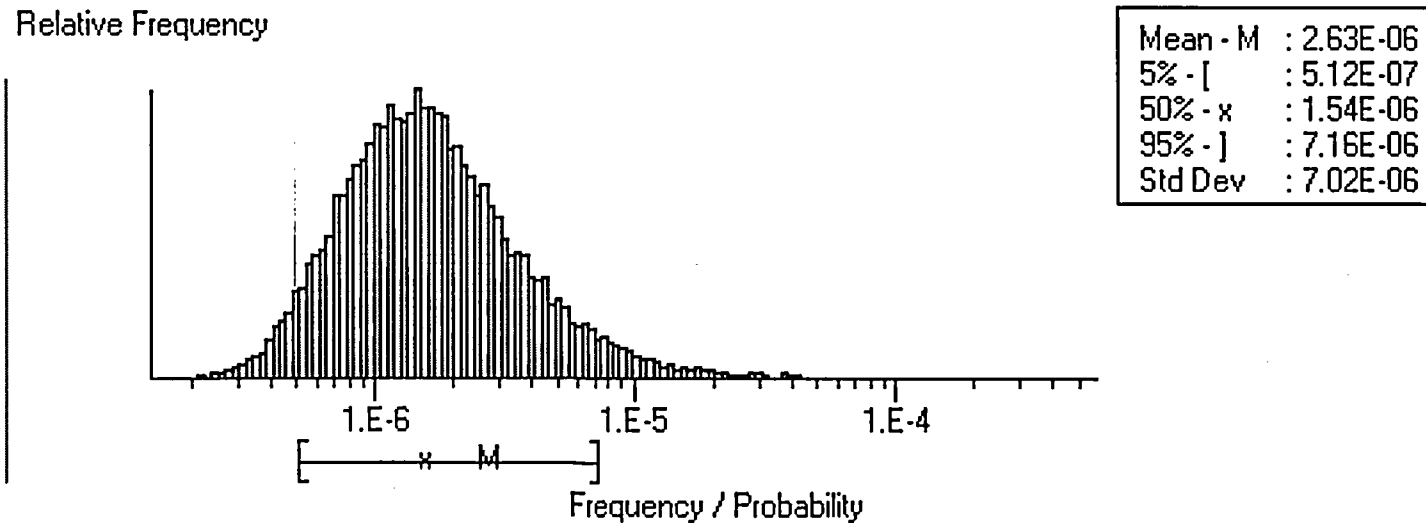


Figure C.3-19 **Distribution for BWR 6, With Independent AC Power**

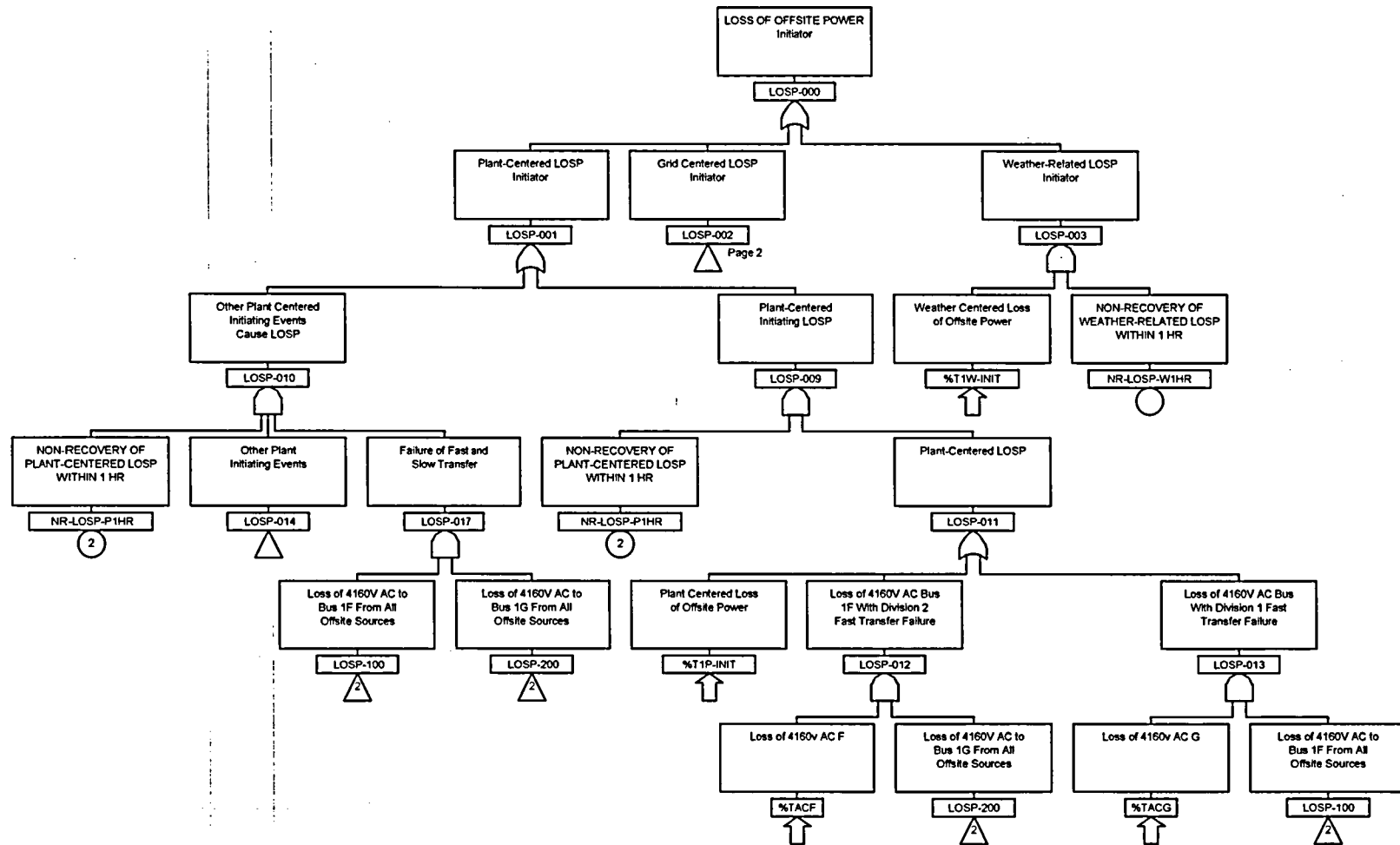


Figure C.4-1 Loss Of Offsite Power Initiating Event Logic (Page 1 of 2)

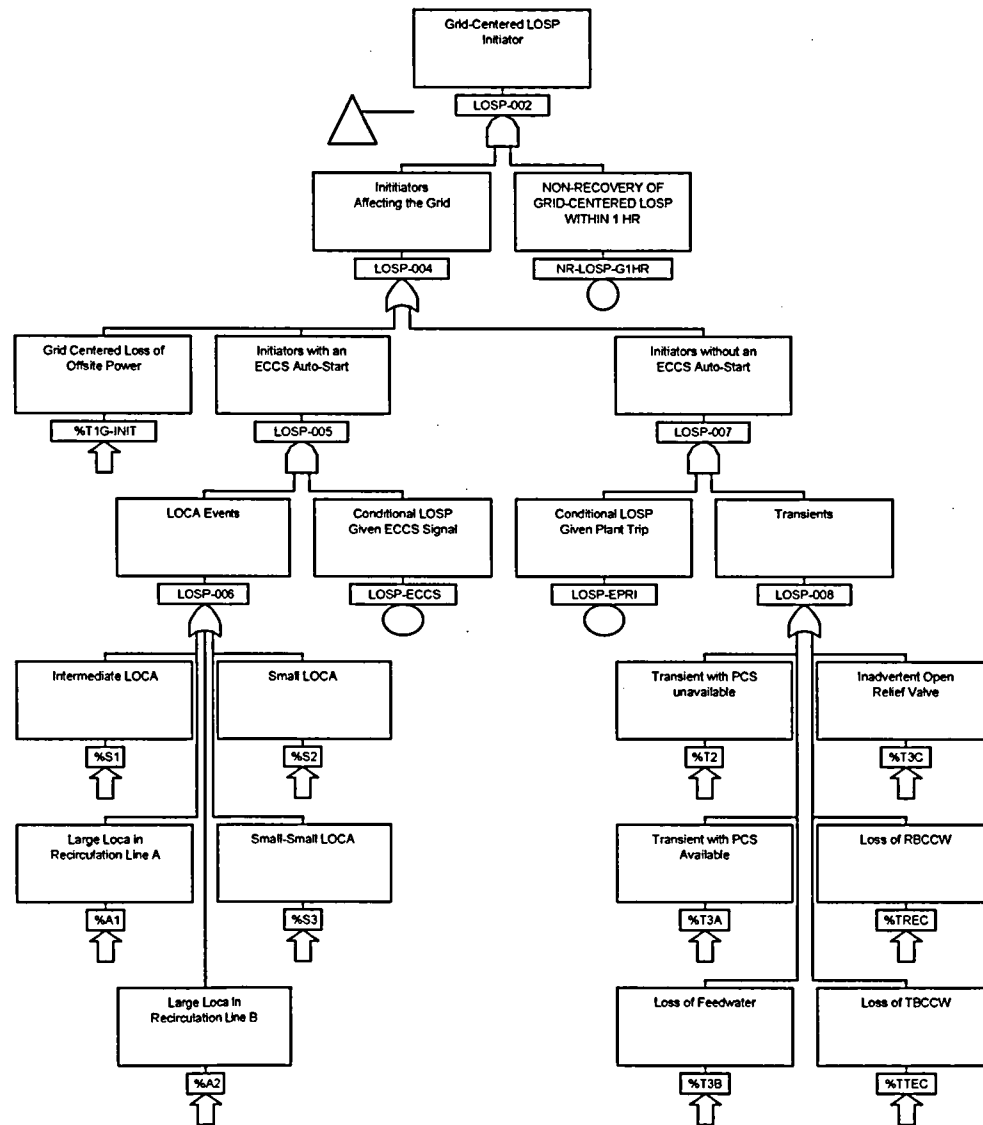


Figure C.4-1 Loss Of Offsite Power Initiating Event Logic (Page 2 of 2)

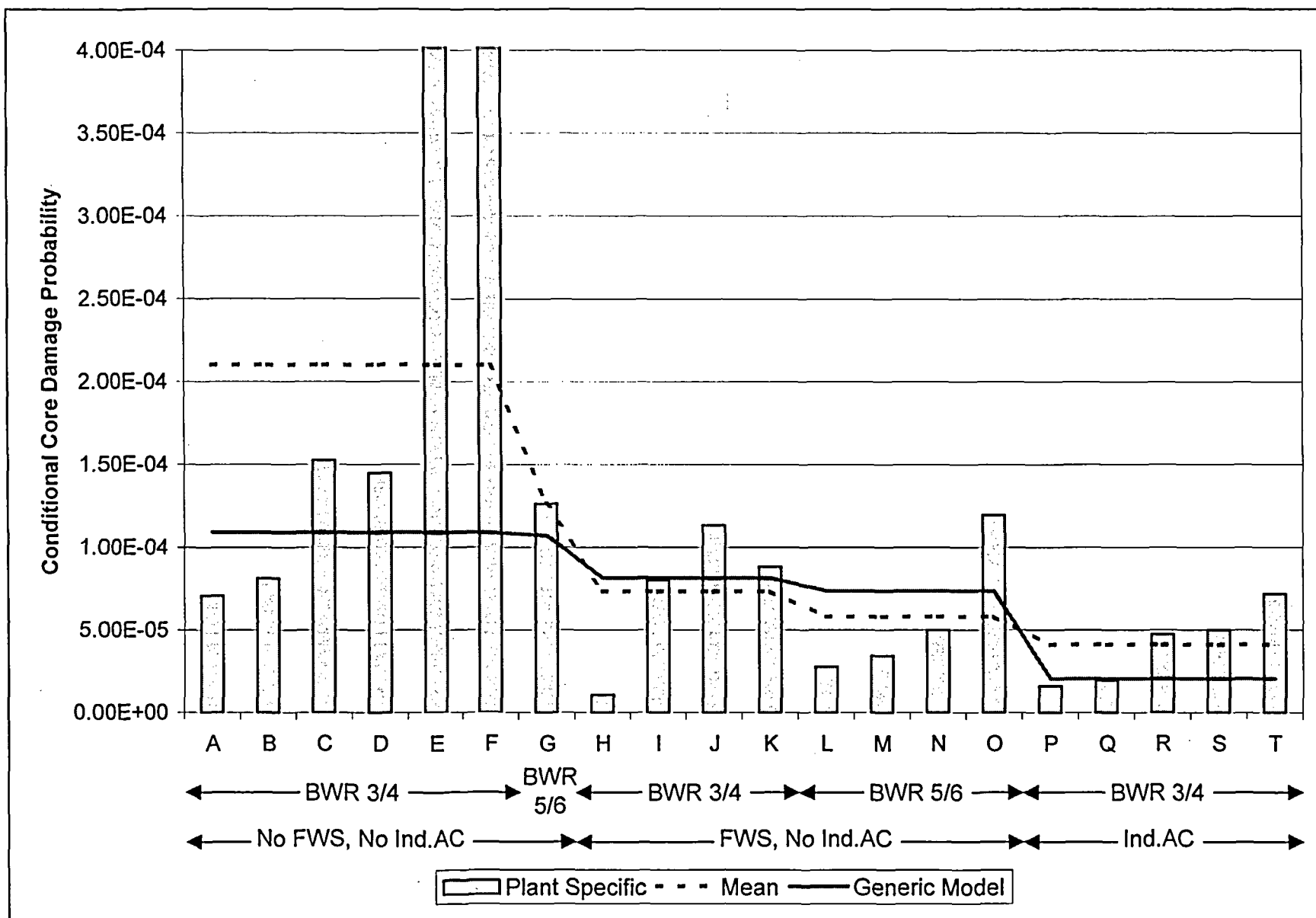


Figure C.4-2 Loss of Offsite Power Conditional Core Damage Probability

Plant	Type	AC Independent Injection	Independent AC Power Source	Battery Life	Number of Diesel Generators per Unit
A	BWR 4	No	No	4 hr	4
B	BWR 4	No	No	4 hr	2
C	BWR 4	No	No	4 hr	4
D	BWR 4	No	No	2.5 hr	2 + swing
E	BWR 4	No	No	2 hr	2
F	BWR 4	No	No	2 hr	2
G	BWR 6	No	No	4 hr	2
H	BWR 4	Yes	No	8 hr	4
I	BWR 4	Yes	No	5 hr	2
J	BWR 4	Yes	No	4 hr	2
K	BWR 4	Yes	No	2 hr	4
L	BWR 5	Yes	No	6 hr	3
M	BWR 5	Yes	No	7 hr	2 + swing for 1 division
N	BWR 6	Yes	No	8 hr	No response
O	BWR 6	Yes	No	4 hr	2
P	BWR 4	Yes	Yes	4 hr	1.5
Q	BWR 3	Yes	Yes	4 hr	1.5
R	BWR 4	No	Yes	4 hr	4
S	BWR 4	No	Yes	4 hr	4
T	BWR 4	Yes	No	2 hr	2

Plant Attributes for Figure C.4-2

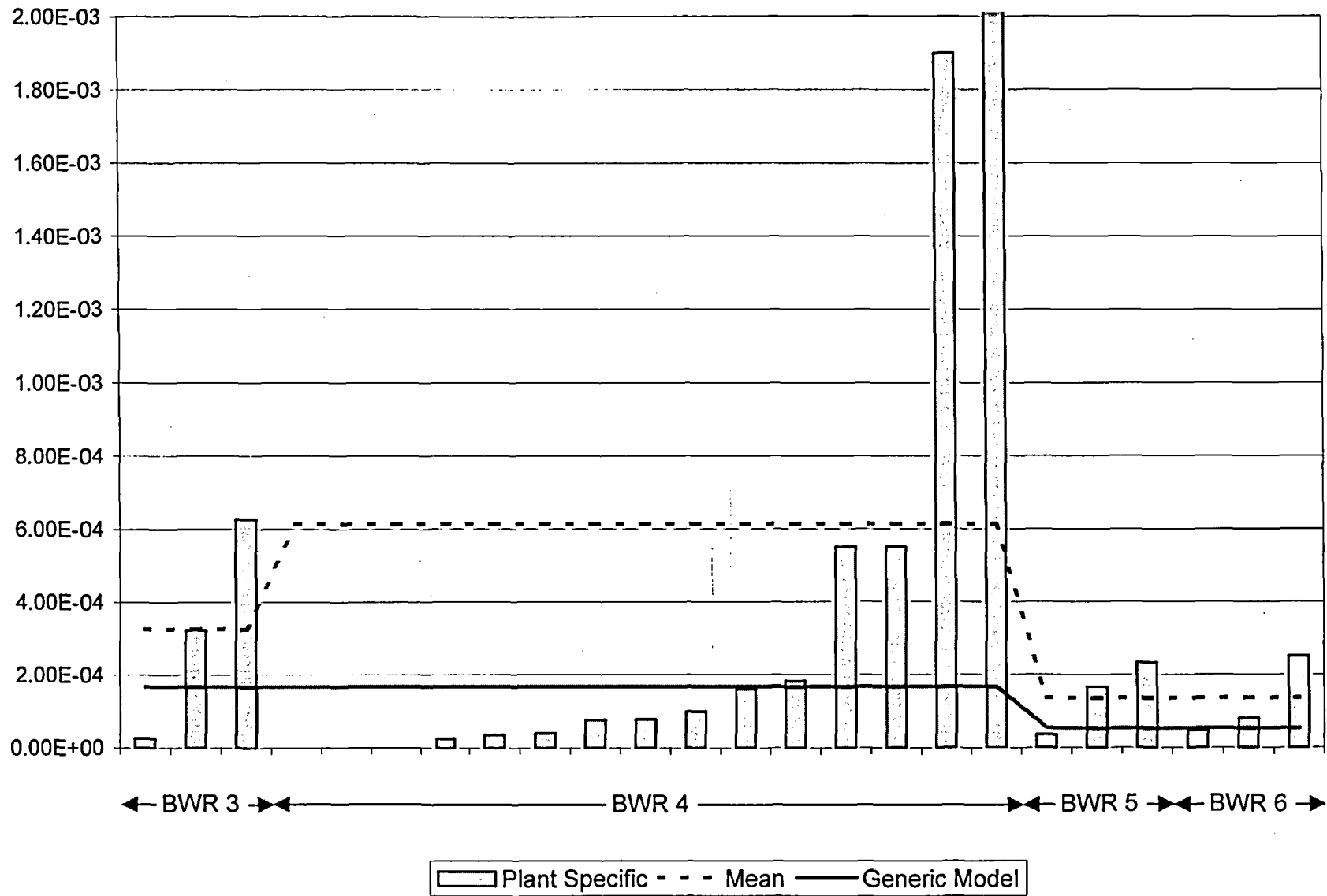


Figure C.4-3 Medium LOCA Conditional Core Damage Probability

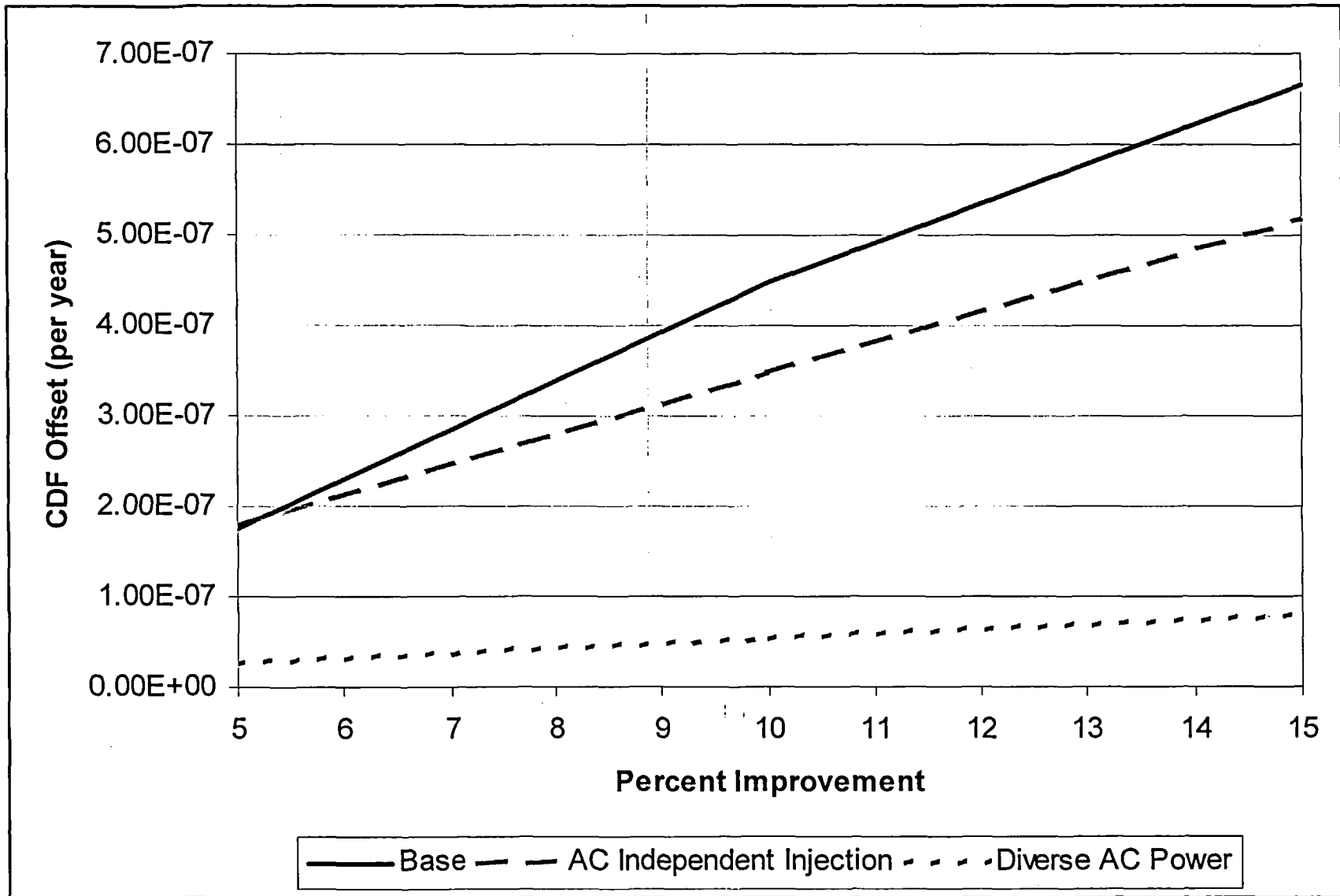


Figure C.5-1 CDF Offset by Varying EDG Parameters

NEDO-33148

APPENDIX D
RESPONSE TO RAIS

TABLE OF CONTENT

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D.4 ENCLOSURE 3: RESPONSES TO NRC COMMENTS ON EPRI TECHNICAL REPORTS 1009110, REVISION 1 AND 1007966 REGARDING THE ISSUE OF DOUBLE SEQUENCING NUCLEAR PLANT SAFETY LOADS	D.4-1

D.1 INTRODUCTION

The original LTR, "Separation of Loss of Offsite Power From Large Break LOCA", was submitted to NRC in April 2004. Following NRC review and comments on the initial LTR, the BWROG agreed to revise the LTR. The revised LTR, describes a risk-informed methodology that facilitates each licensee to prepare a plant-specific exemption request for the LBLOCA/LOOP event. This appendix provides the Requests for Additional Information (RAIs) that resulted from the NRC review of the original LTR and the BWROG responses to those RAIs.

The cover letter transmitting the RAI responses from the BWROG to the NRC is provided on the following pages. Section D.2 of this appendix provides Enclosure 1 to the transmittal letter, the NRC RAIs and BWROG responses. Section D.3 provides Enclosure 2 to the transmittal letter, the Outline of the Revised LTR, as it existed at the time the NRC RAI responses were prepared. Subsequently, the outline of the revised LTR changed slightly as a result of internal review comments, as seen in the main report. Section D.4 provides Enclosure 3 to the transmittal letter, responses to NRC staff comments on EPRI double sequencing reports related to this LTR.

BWR OWNERS' GROUP

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Project Number 691

BWROG-06016
June 30, 2006

Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: Responses to Requests for Additional Information (RAIs) Dated December 21, 2005 and April 20, 2006, Regarding the BWROG Topical Report NEDO-33148, "Separation of Loss of Offsite Power From Large Break LOCA [Loss-Of-Coolant Accident]" (TAC No. MC3042)

ENCLOSURES: (1) Responses to RAIs
(2) Outline of Revised Topical Report NEDO-33148
(3) Response to NRC Staff Comments on EPRI Double Sequencing Reports Related to BWROG LTR NEDO-33148

Dear Sir:

Enclosed please find the BWROG responses (Enclosure 1) to the NRC Requests for Additional Information (RAIs) on the subject Licensing Topical Report (LTR) NEDO-33148, along with an outline of the revised LTR (Enclosure 2), and responses to NRC staff comments on EPRI double sequencing reports related to this LTR (Enclosure 3). The RAIs for the thermal-hydraulic area were dated December 21, 2005; RAIs for the PRA and Electrical areas were dated April 20, 2006. The revised LTR itself will be provided by separate transmittal. The LTR reflect the outcome of our meetings with you on February 14, 2006, and June 14, 2006. At those meetings we agreed to provide a methodology document, rather than a bounding analysis, as the focus of the LTR. Finally, Enclosure 3 should be helpful in reviewing the BWROG responses to the RAIs in Enclosure 1.

We look forward to a timely NRC review and draft Safety Evaluation for the LTR to support the submittal of the lead plant licensing documents this fall.

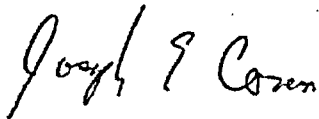
BWROG-06016

June 30, 2006

Page 2

Should you have additional questions please contact Fred Emerson (BWROG Project Manager) at 910-675-5615 or Tony Browning (BWROG Option 3 Committee Chairman) at 319-851-7750.

Sincerely,

A handwritten signature in black ink that reads "Joseph P. Conen". The signature is written in a cursive style with a large initial "J" and a distinct "P".

Joseph Conen
BWR Owners' Group Chairman

cc: Ms. Michelle Honcharik, NRC
Mr. Randy Bunt, Southern Nuclear Operating Company
Mr. Douglas Coleman, Energy Northwest
BWROG Primary Representatives
BWROG Option 3 Committee

D.2 ENCLOSURE 1: RESPONSES TO NRC RAIs

Source	RAI #	Question	Response
PRA		Scope of the TR	
PRA	1	In at least one place (e.g., Page 10) the TR refers to LOCAs up to "large recirculation loop pipe breaks." In other places (e.g., Section 6.0) it refers to 10-inch and larger breaks. Please clarify the break size above which an exemption from the loss-of-offsite power (LOOP) will be requested by licensees. Do all seven options presented in the TR assume the same break size?	<p>The T/H analysis demonstrated mitigation of a double-ended guillotine break of the largest pipe in the Reactor Recirculation system; this was applied consistently for all of the seven options. At the time the original LTR was written, the break size of 10 inches or greater corresponded in the published works to a frequency of 1.0 E-4/year, which when coupled with the conditional LOOP gives LOCA probability of 1.0 E-2, gave the target input probability of 1.0 E-6 for LBLOCA/LOOP.</p> <p>The revised topical will utilize the more recent references for LOCA frequencies, combined with plant-specific conditional LOOP probabilities given a LOCA, to determine the break sizes that will be redefined in the licensing basis. Based on the LOCA frequency values in NUREG 1829, certain plants may be able to justify exemption for break sizes of 7" diameter and above.</p> <p>Finally, all seven options presented in the TR would assume the same break size.</p>

Source	RAI #	Question	Response
PRA		Risk of LOOP with Large Break LOCA	
PRA	2	<p>The TR mentions References 2, 3, and 10 as the basis for the frequency of 1.0E-6 per year for the large break LOCA (LBLOCA) and LOOP combination. In addition, according to Figure C.4-1, the probability of LOOP given a LOCA is 1.0E-2. However, it is not clear how these two estimates are derived from the three references. Please explain how these two estimates have been derived and describe how a licensee would obtain plant-specific estimates of these two parameters.</p>	<p>EPRI developed the LOOP-Given-Large-LOCA probability using an expert elicitation process, described in Reference 10 of the original LTR. That reference recommends a best-estimate value of 1.0E-2 for this probability. The EPRI paper, which was never officially published, provides a detailed description of how this value was derived.</p> <p>The EPRI reference has not been used in the revised LTR. The conditional probability of LOOP given a LOCA is calculated in USNRC's, "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10 CFR 50.46/GDC 35," Revision 1, July 2002. This reference calculates the LOOP given LOCA probability for two plant configurations. The revised LTR recommends the use of these values for the plant-specific analysis. In addition, this reference provides a fault tree method for calculating a plant-specific value for the conditional LOOP given LOCA and this method is recommended in the revised LTR for licensees to calculate plant-specific values. This recommendation is especially useful for plants with multiple switchyards and multiple offsite power sources, as they will be able to calculate a lower value of LOOP given LOCA probability compared to other plants without this feature.</p>

Source	RAI #	Question	Response
PRA	3	<p>NUREG/CR-6538 studied Generic Safety Issue (GSI)-171, "ESF [Engineered Safety Feature] Failure from LOOP Subsequent to a LOCA." Specifically, Section 8.5.1 of NUREG/CR-6538 identified two plant-specific design features that could impact the probability that offsite power will be lost given a LOCA: the electrical switchyard associated with a plant having undervoltage for a significant fraction of time, and the energization scheme implemented to power the safety loads after a LOCA. In addition, for those plants that transfer the source of power feeding the safety buses after reactor trip, a failure of this transfer could cause a loss of power to these buses. Please describe how these potential vulnerabilities are accounted for in the development of the conditional probability of LOOP as a result of a LBLOCA.</p>	<p>EPRI developed the LOOP-Given-Large-LOCA probability using an expert elicitation process. The EPRI paper (Reference 10) presents, in great detail, the sequence of events that must occur to avoid a LOOP-Given-Large-LOCA. The 3 specific design features in this RAI are considered as follows:</p> <ol style="list-style-type: none"> 1. Switchyard having under voltage a significant fraction of the time -- This condition would be a grid-centered factor included in the LOOP-Given-Trip probability of 0.003. The paper specifically considered transmission-provider contracts and communication protocols to determine the likelihood that such conditions would degrade in the future or that considerable variance exists from plant to plant. The experts concluded that neither of these situations is likely, although the report suggests performance monitoring to detect any adverse trends. 2. Energization scheme to power safety loads after LOCA -- The energization scheme is considered in the system voltage analysis and in the plant setup to conform to the analysis. Errors in either of these processes are accounted for by assigning a latent human error probability. The plant-specific details of the energization scheme are not important to this probability estimation. The report notes that verifying consistency of the analysis and the plant set up should be a condition for implementing this risk-informed plant change. 3. Bus transfer after LOCA -- This factor was explicitly considered in the EPRI paper. The experts concluded that there is no difference in the failure probability of this function whether there has been a LOCA or another trip. Therefore, these failure modes are included in the 0.003 LOOP-Given-Trip probability. For a plant that requires no bus transfers, the failure probability is slightly overestimated. <p>The EPRI paper was never published officially, and the revised LTR does not use this EPRI reference for calculating the plant-specific LOOP given LOCA probability. See response to PRA RAI 2 also.</p>

Source	RAI #	Question	Response
PRA	4	<p>The TR states that "... The conditional loss of offsite power events (LOOP given LOCA and LOOP given transient) are modeled as grid centered events ..." The NRC staff notes that a consequential LOOP can also be due to plant-centered causes, such as failures in the switchyard. Please identify all the failure modes that could result in LOOP and define whether each failure is a grid-centered or plant-centered event. How will the potential for plant-centered causes of consequential LOOP be considered in the risk assessment?</p>	<p>The EPRI development of LOOP-Given-LOCA probability (see previous responses) considers grid-centered events and plant-centered events in detail. Generally, grid-centered events are adequately addressed by the database of LOOP-Given-Trip events in the industry. This value is 0.003. Plant-centered events are also addressed by that probability if, according to the experts, there is no difference in failure modes or likelihoods between the trip event and the LOCA event. Other plant-centered failure modes are explicitly considered in the EPRI paper including under-voltage transfers to EDGs from human errors and equipment failures. Five specific, plant-centered failures are quantified in the paper.</p> <p>The LTR modeled all consequential LOOPS as grid-centered because grid-centered events have the least credit for recovery of offsite power. The BWROG believes that this is a conservative approach.</p> <p>As noted in the response to PRA RAI 2 above, the revised LTR does not use the EPRI reference for evaluation of plant-specific LOOP given LOCA probability.</p>

Source	RAI #	Question	Response
PRA		Guidance on Plant-Specific Risk Assessment	
PRA	5	Please describe generally how a licensee would demonstrate that its probabilistic risk assessment (PRA) satisfies Regulatory Guide (RG) 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," guidelines regarding sufficient scope, level of detail, and technical acceptability commensurate with this application.	<p>Regulatory Guide 1.200 addresses the use of the ASME PRA standard and the NEI peer review process (NEI 00-02) for evaluating PRA technical capability. In general, PRA quality has been enhanced through implementation of the MSPI.</p> <p>Plants implementing Option 3 will evaluate their PRAs in accordance with this regulatory guide. The RG specifically addresses the need to evaluate important assumptions that relate to key modeling uncertainties (such as common cause failure methods, success path determinations, human reliability assumptions, etc). Further, the RG addresses the need to evaluate parameter uncertainties and demonstrate that calculated risk metrics (e.g., CDF and LERF) represent mean values. The identified "Gaps" to Capability Category II requirements from the endorsed PRA standards in the RG and the identified key sources of uncertainty will be categorized into one of three categories: (1) Has no impact on risk assessment of Option 3 changes, or (2) Sensitivity cases need to be run to evaluate the impact on the Option 3 changes, or (3) "Gap" in PRA model needs to be addressed prior to using PRA model for Option 3 analysis.</p> <p>In the revised LTR, this process would not be necessary for a case where the qualitative review concludes that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact. (See Step 6). The selected plant modifications would be reflected in the Licensee's next scheduled PRA update.</p>

Source	RAI #	Question	Response
PRA	6	<p>Please describe generally what information a BWR licensee would submit to demonstrate that the five key principles stated in RG 1.174, Section 2 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Section B are met.</p>	<p>The LTR was written to address the five key principles generically for BWROG licensees. In response to the RAIs, the document has been revised to more clearly address each of the five key principles. Each licensee will review the sections related to these principles and adjust the generic discussion to make it plant-specific for the licensee's submittal.</p> <p>The first principle, Compliance with Current Regulations, is addressed generically in Section 3.1 of the revised document. The second, Defense in Depth, is addressed in Section 3.2; the third, Safety Margins, is addressed in Section 3.3; the fourth, NRC Safety Goals, is addressed in Section 3.4; and the fifth, Monitoring Changes, is addressed in Section 3.5. An expanded version of this discussion would be included in each licensee's submittal.</p>
PRA	7	<p>Page 2 of Figure C.4-1 models conditional LOOP events (LOOP given LOCA and LOOP given transient) as part of grid-centered events. According to this figure, a LBLOCA and LOOP are linked with an "AND" gate together with the recovery of offsite power within one hour. In other words, solving the top gate for grid-centered events would yield the following cutset (among other cutsets): LBLOCA * LOOP * NR-LOOP-1HR</p> <p>where NR-LOOP-1HR is the failure to recover offsite power within one hour. This cutset does not appear realistic because a consequential LOOP would occur shortly after a LBLOCA, so the time available for recovery of offsite power is very short, and probably cannot be credited.</p> <p>Please describe how a licensee would be expected to model recovery of the consequential LOOP given a LBLOCA in their risk assessments. Describe and justify the use of any recovery of offsite power.</p>	<p>The logic presented in this figure is not called in the quantification of the large LOCA event tree. When quantifying the large LOCA tree, the BWROG used a version that did not include a recovery factor. The figure presented the base logic rather than all of the permutations. The BWROG reviewed the cutsets from the solutions and confirmed that none of the large LOCA scenarios include this recovery of offsite power.</p> <p>LOOPS following large break LOCAs are assumed to lead directly to core damage. Therefore, licensees need not model recovery of consequential LOOP given a large break LOCA.</p>

Source	RAI #	Question	Response
PRA	8	<p>Figures C.3-4 and C.4-1 present the LBLOCA event tree and fault tree for LOOP events, respectively. The event tree includes top events "TOP-LOSP2 (Offsite Power Available)" and "Recovery." The latter top event appears to be related to recovery of offsite power because the associated branches have the label "REC-LOSP-G6H." It appears that the LBLOCA event tree and fault tree for LOOP events are linked or combined in some way, but a description of the way they are linked was not found in the TR.</p> <p>Please describe in detail how a licensee would be expected to model the consequential LOOP event together with the LBLOCA event tree. The NRC staff notes that a consequential LOOP is likely to be delayed; i.e., not coincident with the LBLOCA. Please discuss in detail how a licensee would determine a plant-specific, best-estimate timing for the LOOP resulting from the LBLOCA, and how the delayed LOOP would be modeled in the PRA.</p>	<p>Although the logic model allowed for the possibility, there are no cutsets that actually reach the REC-LOSP-G6H branch (the conditional probability of TOP-LOSP2 failure is 0.0 for these branches on the large break LOCA event tree); therefore the large break LOCA and the 6-hour recovery factor are not combined in the solution of the event tree. This is because this branch is examined only in scenarios where initial injection is successful, and power must be available for initial injection to be successful. Offsite power recovery is examined only to determine the availability of containment heat removal.</p> <p>See the responses to PRA Question 4 (above) for a description of how the licensee would model recovery of consequential LOOP.</p> <p>Even though the BWROG refers to the LOCA/LOOP as being simultaneous events, in reality the LOOP could occur a few minutes after the LOCA and still be considered a LOCA/LOOP event. BWROG evaluation considers both the simultaneous and delayed (by a few minutes) events to lead to core damage. "A few minutes" is determined by the time for reflooding to occur. Any LOOP after the reflooding is not specifically modeled in the PRA and is not considered to be risk significant.</p>

Source	RAI #	Question	Response
PRA	9	At the beginning of Section C.5, "Risk Calculation for Plant Changes," five steps to assess the impact on core damage frequency (CDF) and large early release frequency are presented. Please define the "base (unaltered case)," e.g., does it include the assumption that a LBLOCA and LOOP lead directly to core damage? Please provide more detail on each of the five steps.	<p>The document has been revised to provide guidance on analyzing the Option 3 changes. The five steps mentioned here are all sub-steps within the step titled "Evaluate Risk Impact of Changes" in the revised document.</p> <p>The current generic PRA model does not include the assumption that large break LOCA/LOOP goes directly to core damage. Step 1 involves quantifying the "Base Case" PRA model with no changes. This version of the model does not include the assumption that Large Break LOCA with LOOP leads directly to core damage. Step 2 involves modifying the Base Case model to represent the change(s) (for example, allowing EDG warmup prior to loading) and including the assumption that Large Break LOCA with LOOP leads directly to core damage. Once the final combination of changes has been determined, the model created in Step 2 becomes the new plant PRA model. Step 2 also quantifies this model. Because the assumption that Large Break LOCA with LOOP is not included in the "Base Case" model, Step 3 is needed to remove the contribution from Large Break LOCA with LOOP that exists in the Step 2 model, but does not exist in the Base Case (Step 1) model to calculate an accurate change in risk resulting from the Option 3 change(s). Step 4 simply calculates the risk decrease (or increase) due to the change by subtracting the Base Case results from the Step 3 results (Step 2 results less any contribution from Large Break LOCA and LOOP). Step 5 just does a calculation similar to Steps 1 thru 4, except the value calculated is the change in LERF. Please see the response to PRA RAI 5 also which points out that in the revised LTR, no quantitative PRA evaluation is done if the qualitative evaluations show the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact.</p>

Source	RAI #	Question	Response
PRA	10	Section C.6.2, "Sensitivity Analyses" does not address the generic probability of LOOP given a LOCA, or the generic frequency of a LBLOCA and LOOP. Please describe how the licensee would be expected to develop this information on a plant-specific basis and to address the uncertainty in the frequency of a LBLOCA and in the conditional probability of LOOP given a LBLOCA?	The revised guidance document provides possible values for LBLOCA frequency and for the conditional probability of LOOP given a LOCA. Uncertainty distribution parameters are provided for these values. LBLOCA frequencies from NUREG-1829, "Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process," and from NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995" are provided in the revised LTR. The conditional probability of LOOP given a LOCA is calculated in USNRC's, "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10 CFR 50.46/GDC 35," Revision 1, July 2002. This reference calculates the LOOP given LOCA probability for two plant configurations. The revised LTR recommends the use of these values for the plant-specific analysis. In addition, this reference provides a fault tree method for calculating a plant-specific value for the conditional LOOP given LOCA and this method is recommended in the revised LTR for licensees to calculate plant-specific values. This recommendation is especially useful for plants with multiple switchyards and multiple offsite power sources, as they will be able to calculate a lower value of LOOP given LOCA probability compared to other plants without this feature.
PRA		Enabled Changes	
PRA	11	Please describe how a licensee would assess the risk impact of adopting multiple options presented in the TR. To what extent, and in what manner, would the licensee evaluate the cumulative risk impact from changes made possible by an exemption to the regulations as requested in the TR?	The BWROG expects each licensee to evaluate the risk impact from each potential change individually. In the revised LTR, a qualitative evaluation, which includes thermal-hydraulic analysis, will be performed for each proposed modification. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. The other modifications will be modeled in the PRA. The results of both the qualitative and quantitative evaluations will aid the licensee in determining which changes to include in the request. Once the specific changes have been selected, an assessment will be made to determine if any additional thermal hydraulic analysis is needed. Then, the combination of all selected changes modeled individually in the PRA will be made in the PRA model and the combined risk impact quantified. This may produce results that lead to another iteration on the selection of changes to include and another quantification of overall risk impact.

Source	RAI #	Question	Response
PRA		3.1 Allow Emergency Diesel Generator Warm Up Prior to Loading	
PRA	12	<p>Section 3.1 states that fast starting of emergency diesel generators (EDGs) decreases their reliability and increases their unavailability. It states that a warm up of 30 to 60 seconds would increase reliability. It further states that many maintenance outages are focused on degradation associated with fast starts. Please provide the technical basis for the claim that 30 to 60 seconds warm up will increase reliability, including data that supports the statement that "many" EDG maintenance outages are attributable to diesel fast starts. Alternately, state how a licensee would determine the appropriate increases in reliability and availability for a plant-specific risk assessment.</p>	<p>There is little data to quantitatively prove that slower starts will increase reliability. EDG experts believe that further elimination of fast starts can improve reliability, but cannot easily provide a number. NRC requested in NRC Generic Letter 84-15 and NRC Information Notice 85-32 that plants consider steps to reduce fast starts. We have eliminated fast starts from testing programs, and a portion of the overall improvement in DG reliability has resulted from these steps, but unplanned starts are still fast starts. It makes sense to further reduce the number of unplanned fast starts by eliminating the fast start logic.</p> <p>EDG fast starts require that the EDG reach rated speed within nominally, 10 seconds. There is a potential for material wear by low-cycle fatigue (LCF) during the fast startup as a result of initial maldistribution of the lube oil within the engine parts. Another functional failure could be related to failure to fast start within 10 seconds even though the unit managed to start and run (say, in 11 seconds). Should this happen, the test is repeated (following attempts to correct the offending condition) until the EDG finally passes the fast start test. This leads to material wear and EDG unavailability during the maintenance and subsequent retest.</p> <p>The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that elimination of EDG fast starts would not require a PRA quantification to be performed as part of individual plant submittals.</p>

Source	RAI #	Question	Response
PRA		3.2 Optimize the Loads Sequenced on to the EDGs	
PRA	13	Section 3.2 states: "If the requirement for automatic loading of all LPCI [low pressure coolant injection] pumps or LPCS [low pressure core spray] pumps onto the diesel generators were eliminated, licensees would perform analyses to determine which equipment would be most beneficial to have automatically loaded." Please describe how a licensee could determine which loads would be beneficial and how it would evaluate the change in risk for a proposed change in EDG loading.	Plants should determine the proper loads and loading sequence from PRA dominant sequences and operator action importance measures related to manual loading of post-transient equipment, and consistency with existing plant operating and emergency procedures. An example of this equipment is battery chargers (as discussed in the LTR).
PRA		3.3 Start EDGs Only When Needed	
PRA	14	Section 3.3 states that one of the safety benefits of revising the EDG start logic "... comes from the reduction of operator burden following accidents and transients." Please describe how a licensee would model this proposed change in their PRA model, or otherwise assess the risk of the proposed change in an acceptable manner.	<p>The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that the reduction of operator burden would not require a PRA quantification to be performed as part of individual plant submittals. If the utility still wants to quantify this improvement through the use of PRA, the following approach may be used.</p> <p>The licensee would first review its PRA model to determine which operator actions might be impacted by a reduction in operator burden. An initial list of operator actions to consider will be assembled by collecting all operator actions with a Fussel-Vesely importance greater than 1×10^{-3}. This list will be screened to reduce the list to actions that could be impacted by the Option 3 change. For these operator actions, the attributes affecting the operator failure rate (performance shaping factors) such as stress level, time available to perform action, concurrent actions, and complexity of action would be reviewed to assess the impact of this change. The human reliability analysis (HRA) would then be reevaluated for the selected actions and the revised HRA values would be input to the PRA model. The revised LTR provides guidelines on how to revise the HRA values.</p>

Source	RAI #	Question	Response
PRA	15	<p>Section 3.3 says that eliminating the anticipatory starting of the EDGs increases diesel availability and reliability, because spurious starts will be reduced. Provide data regarding the number of spurious EDG starts that have occurred that are attributable to emergency core cooling system starting logic and justify the expected improvement in this frequency and provide justification for any improvement in EDG reliability assumed as the result of implementing this change. Alternately, state how a licensee would determine the appropriate increases in reliability and availability for a plant-specific risk assessment.</p>	<p>There is insufficient data to quantify the benefit of eliminating the anticipatory starts because there have been very few failure events due to anticipatory starts. However, on a qualitative basis, eliminating these starts will have a small positive effect on both unavailability and reliability, based on discussions with EDG experts.</p> <p>Given the elimination of large LOCA-LOOP scenarios from the licensing basis (based on CDF being negligible or other reasons), there is no benefit from retaining anticipatory starts in the start logic (gets rid of spurious starts). This eliminates having to correct failures from spurious starts.</p> <p>A review of 37 LERs listed in NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," Table A-2 for unplanned EDG demands during critical operation that were not identified as a loss of offsite power, from 1999 through 2003 (1998 LERs not readily available) yielded no events related to ECCS LOCA signals. The recommendation in the LTR is to remove the logic that starts the EDGs on a LOCA alone and only start them when there is an actual undervoltage or LOOP. Any fast start is believed to have a detrimental effect on EDG reliability, as described in NRC Generic Letter 84-15 and NRC Information Notice 85-32. This would eliminate unnecessary fast starts of the EDGs due to both spurious LOCA signals and actual LOCAs, if offsite power remained available. Even though it is believed that these events are fairly rare, eliminating these fast starts will have a positive effect on EDG reliability, however small that improvement might be.</p> <p>The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that elimination of the anticipatory starts of the EDGs would not require a PRA quantification to be performed as part of individual plant submittals.</p>

Source	RAI #	Question	Response
PRA		3.4 Simplified EDG Testing	
PRA	16	Section 3.4 states: "There is an additional benefit that some of the tests could be simplified, which in turn could result in fewer operator distractions during plant operation." Please describe how a licensee would model the risk impact of simplified tests, including the impact of fewer operator distractions during plant operation.	This is only a qualitative statement that is made in the document. The impact of this effect is not quantified in the document. This impact is difficult to quantify and it is not recommended in the document that licensees attempt to quantify this effect. In any event, we expect this to be a small, but positive impact on risk, for example by reducing potential for plant transients. Less complex testing, such as LOOP/LOCA testing of EDGs, could lead to improvements in test-caused failure probability; however, these were not quantified. The revised LTR also does not propose quantification of these benefits.
PRA		3.5 Increased Motor-Operated Valve Stroke Times	
PRA	17	Please describe how a licensee would determine which motor-operated valves (MOV) to consider for this change, and how it would estimate the risk impact of increasing the selected MOV stroke times?	<p>Licensees would review their maintenance data and determine which MOVs have disproportionate preventive or corrective maintenance associated with preserving a stroke time that is artificially short due to the current LBLOCA-LOOP requirement. This is only a qualitative statement that is made in the document. The impact of this effect is not quantified in the document. This impact is difficult to quantify and it is not recommended in the document that licensees attempt to quantify this effect. In any event, we expect this to be a small, but positive impact on risk.</p> <p>The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that increasing the stroke time of the MOVs would not require a PRA quantification to be performed as part of individual plant submittals.</p>

Source	RAI #	Question	Response
PRA		3.6 Automatically Start One Residual Heat Removal Loop in Suppression Pool Cooling Mode	
PRA	18	<p>Section 3.6 discusses the risk benefit from automatically starting one residual heat removal (RHR) loop in suppression pool cooling mode. In the event of a LOCA and failure of the RHR loop that is aligned for injection, the operator would have to align the other loop (e.g., the one aligned to start in suppression pool cooling mode) to inject.</p> <p>RG 1.174 includes seven elements that serve as guidelines for assessing the adequacy of defense-in-depth. These include: A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation. Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided. System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers). Defenses against human errors are preserved.</p> <p>Please describe how adequate defense-in-depth is maintained for this proposed change. How would a licensee assess the risk associated with the resulting asymmetry in plant design and attendant impact on operator training complexity? How would a licensee assess the potential for RHR system water hammer if it was necessary to switch the suppression pool cooling loop to the injection mode during an accident?</p>	<p><u>Defense-in-Depth</u> The reasonable balance between prevention of core damage, prevention of containment failure, and consequence mitigation is maintained following this change. Making this change would reduce CDF associated with sequences involving loss of containment heat removal because the main system for performing this function would be initiated automatically rather than manually. The change would increase CDF for sequences involving loss of injection, because only one division of RHR would be started automatically in LPCI mode. Further, LPCI could not be used to automatically reflood the core in those LBLOCA scenarios in which the break is in the recirculation loop that receives the LPCI flow. Because loss-of-containment heat removal sequences make up a larger fraction of the BWR risk profile than loss of injection sequences, this change would result in a net reduction in CDF.</p> <p>This change provides improvements to the plant design, but is not related to any perceived weakness in plant design. System redundancy, independence, and diversity are not altered by this change.</p> <p>Defense against human errors is improved slightly by this change, by eliminating the need for operators to manually align suppression pool cooling.</p> <p><u>Plant Asymmetry</u> This will be addressed in the same way that such asymmetries and complexities are currently addressed through plant procedures and training.</p> <p><u>Water Hammer</u> The potential for water hammer is very low probability when the system remains pressurized. In addition, the potential for the alignments that lead to the water hammer events would be the same under the current design and the proposed change. This is because the current plant procedures (and design) require the operators to establish suppression pool cooling as soon as adequate core cooling has been assured. Plant procedures will be written or revised as necessary to minimize the likelihood of this</p>

Source	RAI #	Question	Response
			occurrence.
PRA	19	<u>Miscellaneous Comments</u> The TR contained a number of administrative and clerical errors, including:	See below for responses to Comments 19-1 through 19-8.
PRA	19-1	Section C.4.5, first paragraph, refers to General Design Criteria (GDC) 16 vice GDC 17.	The typographical error will be corrected in revision of TR to reflect correct GDC number (GDC 17).
PRA	19-2	Section C.4.5 states, "Figure C.4-3 shows the generic model logic for loss of offsite power events." However, Figure C.4-3 is entitled "Medium LOCA Conditional Core Damage Frequency [sic]." The correct reference appears to be Figure C.4-1, and it would appear that Figure C.4-3 should refer to "probability" vice "frequency."	The typographical error will be corrected in revision of TR to reflect correct figure number C.3-2 (LOSP event tree). "Frequency" will be changed to "Probability" on Figure C.4-3.
PRA	19-3	Section 9.1 contains 17 PRA assumptions to be validated by plants referencing the TR. There are 18 assumptions listed in Section C.6.1. It appears that numbers 5 and 14 in Section C.6.1 were combined in the Section 9.1 list. It would be clearer if these lists were consistent.	The two lists of assumptions will be made consistent in the revision to the TR.
PRA	19-4	Section 2.2, Page 6 cites References 3, 8, and 10 as the basis for the consequential LOOP probability used in the TR. Section 4.2, Page 16 cites References 2, 3, and 10.	All four references will be listed in both places in the revision to the TR.
PRA	19-5	Table C.6-1, Page C-66 discusses offsite power configurations. The "assessment" column states: "Section C.3.5 discusses this aspect of the generic model as it applies to other plant configurations." However, Section C.3.5 is "Simplified Level 2" and does not appear to address offsite power configurations.	"Section C.3.5" will be corrected to "Section C.4.5" in the revision to the TR.

Source	RAI #	Question	Response
PRA	19-6	Table C.6-1, Page C-67 discusses battery depletion time: "Section C.3 discusses the impact that different battery ratings have on the analysis." The NRC staff could not find this discussion in the TR.	"Section C.3" will be corrected to "Section C.4" in the revision to the TR.
PRA	19-7	Figure C.4-1 is very difficult to read.	A clearer image for Figure C.4-1 will be used in the revision to the TR.
PRA	19-8	Section C.4.5, "Offsite Power Configuration" states that "Figure C.4-3 shows the generic model logic for loss of offsite power events." It appears that the correct reference is Figure C.4-1.	The typographical error will be corrected in revision of TR to reflect correct figure number C.3-2 (LOSP event tree).
PRA	20	The sensitivity study in Section C.6.2.4 shows that not inhibiting the automatic depressurization system (ADS) causes an increase in CDF for the "LPCI Does Not Start With On [sic] Offsite Power" case. This same case shows a CDF decrease if ADS inhibit is credited. However, Table C.6-1, on Page C-63, states for the ADS assumption: "The results show that this assumption does not impact the conclusions of this report." Please explain these results.	There is a small decrease in CDF for this case, with the base model (ADS inhibited). There is also a small increase in CDF for this case when ADS is not inhibited. However, both of these changes to CDF are very small, especially in comparison to the assumed CDF increase of 1×10^{-6} from LBLOCA/LOOP. It is on this basis that the statement is made concerning the assumption not impacting the conclusions of the report.
PRA	21	Section C.6.2 presents seven sensitivity analyses. Several apparent errors and a non-intuitive presentation format render this section very difficult to understand. Please address the following if Section C.6.2 is to be retained:	See below for responses to Comments 21-1 through 21-8.
PRA	21-1	All of the tables in Section C.6.2 use "CDF Decrease" as the metric; this is difficult to interpret as discussed in specific cases below. All of the tables have a column, "LPCI Does Not Start With On Offsite Power." Please provide a more descriptive heading.	The typographical error will be corrected in the revision to the TR. Heading will read "LPCI Not Supplied by Onsite Power" or "LPCS Not Supplied by Onsite Power", as appropriate.

Source	RAI #	Question	Response
PRA	21-2	Tables C.6.2.2 through C.6.2.4 have the same two row labels, which are apparently meant to define the base case and sensitivity case conditions. The latter two tables should have rows related to "Service Water Injection Source" and "ADS Actuation," respectively.	The typographical error will be corrected in the revision to the TR to make the row labels more descriptive of the sensitivity cases.
PRA	21-3	For the sensitivities involving "LPCI Does Not Start With On Offsite Power," Tables C.6.2.2, C.6.2.3, C.6.2.5, and C.6.2.7 appear to show an improvement in risk (a larger "CDF Decrease") as a result of model changes that would be expected to increase risk.	<p>These sensitivity analyses were done for the purpose of showing that plant to-plant differences do not affect the LTR conclusion on risk-benefit of the identified changes. With the proposed approach to do plant-specific analyses in the revised LTR, there is no longer a need for these sensitivity studies.</p> <p>For those cases, the raw CDF is higher and the CDF decrease is also higher. The expected increase in risk (CDF) is present for these cases, but is only an interim value used to calculate the CDF decrease shown in the referenced tables. The CDF decrease shown in the tables reflects the increased importance of removing LPCS or LPCI from onsite power given the model changes related to the sensitivity.</p>
PRA	21-4	For sensitivities involving "Increased DG Reliability," Tables C.6.2.1, C.6.2.3, C.6.2.5, and C.6.2.7 appear to show an improvement in risk (a larger "CDF Decrease") as a result of model changes that would be expected to increase risk.	<p>These sensitivity analyses were done for the purpose of showing that plant to-plant differences do not affect the LTR conclusion on risk-benefit of the identified changes. With the proposed approach to do plant-specific analyses in the revised LTR, there is no longer a need for these sensitivity studies.</p> <p>For those cases, the raw CDF is higher and the CDF decrease is also higher. The expected increase in risk (CDF) is present for these cases, but is only an interim value used to calculate the CDF decrease shown in the referenced tables. The CDF decrease shown in the tables reflects the increased importance of improved EDG reliability given the model changes related to the sensitivity.</p>

Source	RAI #	Question	Response
PRA	21-5	The results for Tables C.6.2.1 and C.6.2.2 are opposite for the two model changes shown; i.e., risk goes up for one change and down for the other as a result of the same sensitivity analysis.	<p>These sensitivity analyses were done for the purpose of showing that plant to-plant differences do not affect the LTR conclusion on risk-benefit of the identified changes. With the proposed approach to do plant-specific analyses, there is no longer a need for these sensitivity studies.</p> <p>The values shown in the tables reflect the relative importance of removing LPCS or LPCI from onsite power (or increasing EDG reliability) with the changes related to the sensitivity in place. (See responses to questions 21-3 and 21-4).</p>
Electrical	1	Section 1, Introduction, describes the scope of the TR to the coincident large break LOCA (LBLOCA) with a loss-of-offsite power (LOOP).	See below for responses to RAIs 1a and 1b.
Electrical	1a	The TR indicates that the capability of mitigating a LBLOCA will be removed from the design requirements for the onsite power system. Confirm that the capability to respond to a LBLOCA will remain if offsite power remains available	Yes. The capability of mitigating a LBLOCA, if offsite power is available, will be retained. The retention of this capability is the key difference between this LTR and the proposed 50.46a.
Electrical	1b	With only the offsite power system remaining to power the LBLOCA mitigating systems, describe the design and acceptance criteria for an operable offsite power system. Also, describe how you propose to modify the nuclear power plant technical specifications to ensure an adequate offsite power system will be available when needed.	Because this capability is being retained within the design and licensing basis, no additional reliance on offsite power is needed. Therefore the existing design and TS requirements are adequate.
Electrical	2	Section 3.1, Allow Emergency Diesel Generator (EDG) Warm Up Prior to Loading, indicates that for small breaks, based on the time required to depressurize the reactor system, a diesel start and load time of less than 100 seconds would result in an acceptable peak cladding temperature (PCT).	See below for responses to RAIs 2a and 2b.

Source	RAI #	Question	Response
Electrical	2a	Confirm that for this scenario, the low-pressure pumps would automatically load onto the EDG and the high-pressure injection systems would not be required. If this is true, justify the deletion of the defense-in-depth caused by the elimination of the high-pressure response.	<p>The high-pressure core cooling response is not being eliminated as part of this modification. However, in the analysis, high-pressure injection is <u>assumed</u> to have failed under single failure criteria. If the high-pressure systems are assumed functional, very little EDG loading will be required for much longer intervals.</p> <p>Section 3.1 indicates that the controlling factor is the time to depressurize to the low-pressure ECCS injection permissive, which is greater than 100 seconds. This means that there is sufficient time to allow the EDGs to warm up prior to loading the low-pressure pumps, given a loss of offsite power. Defense-in-depth has been maintained.</p>
Electrical	2b	Provide the limiting size of the small or medium break LOCA (SBLOCA or MBLOCA) that would be acceptable if it took 100 seconds for the EDG to start and load. Also, describe the range of consequences associated with break sizes from the limiting SBLOCA up to the design basis break of the LBLOCA with a EDG start and load time of 100 seconds.	<p>Appendix B of the LTR demonstrates that all break sizes can be mitigated using an approximately 100 second start time using best-estimate methods and severe accident success criteria. The implementing Licensees are required to maintain their design bases for the small and medium break LOCAs and continue to meet 50.46 requirements after implementing the LTR changes. Each plant will have to demonstrate this in its application. The demarcation between design basis and beyond design basis LOCAs is based on the initiation frequency of certain pipe breaks and the conditional probability of LOOP at the implementing plant. The implementing plant will decide the specific point of demarcation. As an example, based on the LOCA frequency values in NUREG-1829, certain plants may be able to justify exemption for break sizes of 7" diameter and above.</p>

Source	RAI #	Question	Response
Electrical	3	<p>Section 3.2, Optimize the Loads on to the EDGs, indicates that a new automatic load sequence would replace some of the high capacity (emergency core cooling system (ECCS)) pumps such as low pressure core spray and low pressure core injection (LPCI) with support equipment such as battery chargers, drywell coolers, and some equipment closed cooling loops.</p> <p>Identify those plants that do not automatically load the safety-related battery chargers onto the EDG at present. Justify why the battery-chargers are not automatically loaded as soon as possible to keep its reflected load on the EDGs low compared to its current-limited rating that would be required if the battery chargers are manually loaded after two to eight hours.</p>	Since this LTR is no longer intended be a bounding analysis per the BWROG meeting with NRC on February 14, 2006, a response to this question is no longer required.
Electrical	4	Section 3.3, Start EDGs Only When Needed, proposes to eliminate the anticipatory LOCA start of the EDGs and only rely on the low voltage signals to start the EDGs.	See below for responses to RAIs 4a and 4b.
Electrical	4a	Confirm that it is the intent to only start the EDGs on undervoltage (with a fast start)	Yes, for this option, It is the intent to only start the EDGs on bus undervoltage or degraded voltage conditions, with a fast start. However, it is expected that most plants will combine this option with the change described in Section 3.1, which deals with eliminating the fast start, allowing the EDGs to warm up prior to loading.
Electrical	4b	Confirm that is your intent to not start the EDGs at all on "only" LOCA, not even using a "slow" start to bring the EDG up to speed for a controlled loading.	Yes, it is the intent to not start the EDGs when only a LOCA signal is present.

Source	RAI #	Question	Response
Electrical	5	Describe the response of the plant to the full range of LOCAs between "a few seconds" delayed LOOP and "a few minutes" delayed LOOP.	<p>Our evaluation considers both the simultaneous and delayed (by up to a few minutes) LOOP events as leading to core damage. "A few minutes" is determined by the time for core reflood to occur. Any LOOP after the reflooding is not specifically modeled in the PRA and is not considered to be risk significant.</p> <p>Only a large break LOCA/LOOP was considered in this topical. Small and intermediate breaks, with delayed LOOP, are outside the current licensing basis of the plants. It is not the intent of this LTR to revise that licensing basis. This approach was agreed to with NRC staff in the presubmittal meetings.</p>
Electrical	6	<p>Describe differences and the trade offs between [fast] starting and running the EDGs unloaded, [and] a slow start and warmup scenario on:</p> <p>Lubrication efficiency</p> <p>Capability to accept load (any differences in the "Probability to Accept Load")</p> <p>The elimination of the delayed "Failure to Start" probability</p>	<p>A diesel generator expert has indicated that prelubrication and slow starts do help lubrication efficiency. We do not want to make fast starting or running the EDGs unloaded for long periods of time common practices in the industry because they can lead to EDG degradation over time. None of the scenarios listed would affect capability or probability to accept load.</p>

Source	RAI #	Question	Response
Electrical	6a (new, from NRC clarification)	<p>From 3.3, Start EDGs Only When Needed, Page 12</p> <p><i>Another safety benefit of eliminating the anticipatory EDG starts comes from an increase in diesel availability and reliability. When spurious EDG starts occur, remedial actions, such as running the EDG under load for a period of time to clear cylinder soot buildup, are typically necessary to restore the equipment to full integrity. This effect has been analyzed using the generic PRA model discussed in Section 4. Additionally, a diesel generator that has been unnecessarily started during an accident or transient and has been successfully secured may incur damage if offsite power is subsequently lost and an actual start demand occurs. One mechanism for this damage is that the hotter oil in a recently shutdown EDG does not lubricate all portions of the EDG, such as turbochargers, as well as if the oil was at normal, standby temperature.</i></p> <p><i>A third safety benefit of eliminating the anticipatory EDG starts is that there should be fewer spurious EDG actuations. A reduction of the number of signals that will cause a start will result in a reduction of the number of spurious starts. Since any reduction in demands reduces wear on the equipment, unavailability should decrease and reliability should increase as a direct consequence of this change.</i></p> <p>Eliminating the "Anticipatory EDG start signal" Places more reliance on the operator action to "manually start" or wait for the "LOCA start signal" decreasing the reliability of the starting circuit. Also the "Anticipatory EDG starting" eliminates the delayed failure to start because the EDG is</p>	<p>While diesel generator experts agree that incremental improvements in current reliability and unavailability would be difficult to quantify, they also feel that the recommended relaxation is at least risk neutral and may afford a small improvement in these performance parameters.</p> <p>To address the specific questions, after the elimination of the anticipatory start signal, the diesels will continue to start on an undervoltage signal (LOOP) and not a LOCA start signal. There is no additional reliance placed on operator action to start the diesel. The anticipatory LOCA signal is viewed as a detriment in all LOCA scenarios except those with delayed LOOP, which is a small fraction of all LB LOCA/LOOPs. The BWROG PRA evaluation, which included delayed LOOP scenarios, demonstrated that risk is improved by removal of the anticipatory LOCA start, as it allows operator actions to be applied to more beneficial mitigative actions (see Section C 5.5 of the LTR) than securing an unneeded running diesel.</p> <p>Diesel generator experts have indicated that prelubrication and slow starts do help lubrication efficiency. We do not want to make fast starting or running the EDGs unloaded for long periods of time common practices in the industry because they can lead to EDG degradation over time. In addition, the BWROG will remove this statement (regarding lubrication efficiency) in the revised LTR.</p> <p>Regarding the question related to differences in loading schemes depending on the power source available, this is a plant-specific matter and will be addressed by the plant if this relaxation is sought. The appropriate surveillance testing will be reflected in each licensee's application.</p>

Source	RAI #	Question	Response
		<p>already running.</p> <p>The mention of lubrication efficiency in the first paragraph (hotter oil in a recently shutdown EDG does not lubricate all portions of the EDG) is unsupported by the discussion. How long does the engine have to be running unloaded to heat the lubricating oil such that its lubricating properties are in question? Why is this different than the lubrication in a hot running engine?</p> <p>The statement in the second paragraph (unavailability should decrease and reliability should increase) is not supported by the discussion.</p> <p>From 3.4, Simplified EDG Testing, page 13</p> <p><i>For example, to satisfy the accident response assumptions associated with a LLOCA concurrent with LOOP, RHR pumps must load onto the DG-powered board immediately (typically less than 1 second) after the DG ties to the board. The DG is therefore subjected to the application of a very large load just a few seconds after its cold, fast start. Additional loads are sequenced onto the DG in fairly quick succession. The timing relays which accomplish this loading have tight tolerances, both to assure reflood times are within those assumed in the accident analyses, and also to ensure that the DG can recover adequately before the next load is applied.</i></p> <p><i>Upon separation of the LOOP and LOCA events as requested by this LTR, the DG is allowed a warm-up period prior to connecting to the associated electrical board. The start times of the RHR pump and other loads are not as critical in a</i></p>	

Source	RAI #	Question	Response
		<p><i>smaller break scenario, so the timing relays' tolerance need not be so tight, and the DG can be allowed a greater recovery time between load applications. The longer start times impose less stress upon the DG and require less timing precision in the loading sequences, while maintaining adequate margins to accident analyses assumptions.</i></p> <p>These paragraphs imply that the EDG will accept load more reliable when the load is applied slowly. This statement is not supported by the discussion. In addition the implication that there will be one loading sequence for LBLOCA when powered from the offsite power supply and a different loading sequence for MBLOCA and smaller LOCAs when powered from the onsite power supply will unnecessarily complicate the ESF load control circuit leading to more testing, not less testing.</p>	
Electrical	7	<p>Section 3.4, Simplified EDG Testing, indicated the changes would result in a relaxation of acceptance criteria. It would appear that additional testing would be required to test for different LOCA break sizes and different loading responses depending on whether offsite power was available or not. Describe what testing acceptance criteria can be relaxed.</p>	<p>Possible Tech Spec changes include:</p> <p>SR 3.8.1.7 (NUREG-1433) can be relaxed to reflect a new diesel start time</p> <p>SR 3.8.1.9 is modified to reflect any change in single largest post-accident load</p> <p>SR 3.8.1.11 can be relaxed to reflect the new diesel start time</p> <p>SR 3.8.1.12 is eliminated with the elimination of the LOCA-only start</p> <p>SR 3.8.1.15 can be relaxed to reflect the new diesel start time</p> <p>SR 3.8.1.17 is eliminated with the elimination of the LOCA-only start</p> <p>SR 3.8.1.18 can be relaxed to reflect the new optimized diesel loading sequence</p> <p>SR 3.8.1.19 can be relaxed to reflect the new diesel start time and new optimized loading sequence</p> <p>SR 3.8.1.20 can be relaxed to reflect the new diesel start time</p>

Source	RAI #	Question	Response
Electrical	8	Some BWR EDGs are only capable of starting the large residual heat removal (RHR) loads at the beginning of the loading cycle where margin exists between EDG rating and load demand. Describe how this restriction will affect the proposed changes.	Plants implementing this LTR will need to insure that their loading sequence is within the capability of the EDGs.
Electrical	9	Describe what regulatory requirements are referenced in the statement "...loads that often have to be load shed under the current regulatory requirements." Clarify if this is an inference to the voltage and frequency limits that may be challenged using an undersized EDG.	No such inference is intended. Diesel loading is currently optimized for unlikely event sequences (LBLOCA/LOOP) as required by GDC 35. The LTR will allow loading sequences to be optimized for more likely event sequences.
Electrical	10	Section 3.5, Increased MOV [motor-operated valve] Stroke Times, states separating a LBLOCA from LOOP will allow slower valve stroke times. Explain why the faster stroke times will not be required if the ECCSs are powered from offsite power.	Current MOV stroke times are set short enough so that the core can be re-flooded prior to exceeding regulatory limits (PCT) for all break sizes following a loss-of-offsite power and subsequent EDG start and load. When offsite power is available, the time delay due to DG start and load times is no longer the limiting parameter for ECCS injection. After implementing the LTR, with offsite power available, longer MOV stroke times will result in ECCS injection no later than when powered from the DG. Each plant seeking this relaxation will need to demonstrate that the relaxed MOV stroke times will continue to meet the current regulatory limits.
Electrical	11	Section 3.5 also states that thermal-hydraulic analysis has shown that adequate PCT can be maintained for a wide range of stroke time relaxations.	See below for responses to RAIs 11a and 11b.
Electrical	11a	It is not clear how stroke times for MOVs which can be powered by both the offsite power system and the onsite power system are being addressed in this section. Is the family of valves being considered restricted to only those systems which are not required to respond to the LBLOCA? Have stroke time relaxations been discussed in a separate TR or requested under a separate plant-specific change request that may provide further	No. The family of valves being considered for stroke time relaxation includes only those required to respond to the LBLOCA (ECCS injection valves). Each plant seeking this relaxation will need to demonstrate that the relaxed MOV stroke times will continue to meet the current regulatory limits.

Source	RAI #	Question	Response
		clarification?	
Electrical	11b	Section 3.5 notes that one MOV has experienced severe damage during a test under these conditions. Describe the damage and the relation to fast stroke times. Confirm that the damage was not caused by incorrectly set thermal overload relay or torque switch selection.	This reference will be removed from the LTR.
Electrical	12	Clarify the statement in Section 3.5 that larger operators can add to EDG loading constraints. Explain why the existing (short-time) EDG ratings are challenged by the higher load of the existing fast acting MOVs.	In general, larger operators impose greater loads on the EDGs. However, this statement should not be construed to mean that existing loads challenge the EDG ratings beyond design requirements.
Electrical	13	In general, pump suction valves affect pump net positive suction pressure and pump discharge valves affect pump horsepower. Address the differences between the suction and discharge valves for the ECCS pumps.	See below for responses to RAIs 13a and 13b.
Electrical	13a	Confirm that the slower stroke times will not affect the starting or restarting loads seen by the EDG.	Slower stroke times for the discharge valves reduce the rate of pump electrical loading seen by the EDGs.
Electrical	13b	Confirm the ECCS pumps will not have a problem with inadequate suction pressure.	ECCS suction valves are maintained in the open state for standby readiness. No ECCS suction valves have to change state during the early stages of the event. Stroke times for these valves are not changed by this LTR.

Source	RAI #	Question	Response
Electrical	14	Clarify the statement in Section 3.6, Automatically Start One RHR Loop in Suppression Pool Cooling Mode (SPC), that in order to make this change, a licensee would have to deterministically demonstrate that it could still mitigate the LBLOCA with offsite power available and a single active failure. The NRC staff believes this section can only apply to those plants that have two RHR pumps per division where it would be proposed to permanently re-align one of the two RHR pumps per division to the SPC mode. Otherwise, clarify why this has not already been demonstrated under the existing requirements.	<p>A licensee should deterministically demonstrate that it could still mitigate the LBLOCA with offsite power available and a single active failure to confirm that compliance with the design basis is not degraded through implementing this relaxation.</p> <p>The permanent realignment described by the NRC is not required in order to implement this option. The NRC's perception that "this section can only apply to those plants that have two RHR pumps per division where it would be proposed to permanently re-align one of the two RHR pumps per division to the SPC mode" is not correct. It is impractical to align RHR systems in BWRs in the manner described.</p> <p>Current regulatory requirements to consider a simultaneous LOOP and single failure preclude implementation of this option.</p>
Electrical	15	Clarify the last paragraph of Section 3.6 to explain why the core damage frequency (CDF) due to loss of containment heat removal is higher than damaging the core (i.e. melting the core) from failure to reflooding the core because of loss of injection.	This statement is simply a general statement summarizing the PRA results for BWRs. The core damage frequency contribution from loss of containment heat removal sequences is higher than the contribution from loss of injection sequences. In any case, per the revised LTR, each licensee will calculate its own change in CDF and LERF (decrease or increase) due to starting one RHR Loop in Suppression Pool Cooling mode, using its own plant-specific PRA model.
Electrical	16	Section 3.7, Eliminate LPCI LOOP Select, states that "In the current LOCA analyses for Loop-Select plants, the logic is assumed to fail (i.e. select the broken loop) for all breaks less than or equal to 0.5 ft ² . This is well into the large break range, so elimination of this function will not affect other postulated accidents." Describe why other postulated events LESS than 0.5 ft ² will not be a concern.	<p>Loop select logic is used only to mitigate Large Break LOCAs, and for no other accidents or transients. As 0.5 ft² is considered to be a Large Break LOCA, <u>all</u> Small and Intermediate Break LOCAs are less than 0.5 ft². Thus, the currently assumed failure of the Loop Select logic in the deterministic T/H analysis for all breaks less than 0.5 ft² has no impact on SBLOCA or IBLOCA mitigation.</p> <p>Thus, removing the Loop Select logic will have, at worst, no impact but could have a positive impact on the T/H analysis of SBLOCA/IBLOCA depending on single failure assumptions.</p>

Source	RAI #	Question	Response
Electrical	17	Section 4.3.1, Quantitative Impact of Optimizing EDG Loads, appears to attempt to provide a risk trade-off of manually loading two to four (or more) battery chargers before the batteries discharge to the point of inadequate direct current voltage against the elimination of core injection on a LBLOCA. Clarify why the consequences of a discharged battery are comparable to damaging the core and a deliberate loss of the primary fission barrier.	The trade-off does not involve loading battery chargers onto the EDGs at the expense of eliminating low-pressure injection. The trade-off is that excess low pressure ECCS capacity (either all LPCS pumps or 2 of 4 LPCI pumps) is no longer automatically loaded onto the EDGs, which would allow more beneficial loads, from a core damage risk perspective, (such as battery chargers) to be automatically loaded. The complicated tasks of AC and DC load shedding would be greatly reduced or eliminated. The generic BWR4 PRA model showed a risk decrease resulting from making this change. In any case, per the revised LTR, each licensee will evaluate this change using its own plant-specific PRA model to calculate the change in CDF and LERF resulting from this change.
Electrical	18	Section 4.3.4, Qualitative Risk Reductions, addresses three areas in the first paragraph: EDG Availability, EDG Reliability and Operator Action Reliability. The implication is that spurious starts reduce EDG availability and reliability. Describe how many false starts can be attributed solely to a false LOCA signal and what percentage of unavailability and unreliability can be attributed to that function.	A review of 37 LERs listed in NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," Table A-2 for unplanned EDG demands during critical operation that were not identified as a loss of offsite power, from 1999 through 2003 (1998 LERs not readily available) yielded no events related to ECCS LOCA signals. The recommendation in the LTR is to remove the logic that starts the EDGs on a LOCA alone and only start them when there is an actual undervoltage or LOOP. Any fast start is believed to have a detrimental effect on EDG reliability, as described in NRC Generic Letter 84-15 and NRC Information Notice 85-32. This would eliminate unnecessary fast starts of the EDGs due to both spurious LOCA signals and actual LOCAs, if offsite power remained available. Even though it is believed that these events are fairly rare, eliminating these fast starts will have a positive effect on EDG reliability; however small that improvement might be.
Electrical	19	If the existing LOCA logic is a significant contributor to spurious EDG starting and has a negative effect on EDG availability and EDG reliability, clarify why the existing deficient logic has not been corrected under the Maintenance Rule and describe your recommendation to revise the logic.	The current logic is optimized to respond to only LB LOCA/LOOP scenarios, which is required by the current licensing basis. The purpose of this LTR is to provide justification for an exemption from this licensing basis requirement so that this beneficial change can be implemented. As stated in the response to Question 18 above, it is acknowledged that spurious EDG starts from this logic are now rare; hence it would not be addressed under the Maintenance Rule. The recommendation to remove the LOCA logic to start the EDGs is aimed at reducing the number of fast starts and thus incrementally improving EDG reliability and unavailability. Just as important, it also removes the operator burden from having to respond to these unnecessary starts.

Source	RAI #	Question	Response
Electrical	20	It appears that an arbitrarily assumed improvement of 10 percent in operator action reliability was used to justify the offset in the increase in CDF from the proposed changes. Clarify how an operator action hours into the accident, can offset the immediately assumed damage to the core from failure to recover.	The offsets are reductions in overall risk (CDF and LERF) due to reductions in the frequency of other PRA sequences, not LBLOCA/LOOP, resulting from benefits associated with making one or more of the changes described. These reductions are used to balance the increase in risk resulting from assuming that a LBLOCA/LOOP goes directly to core damage. Any improvement in operator reliability (not necessarily 10%) can be used to show that the overall changes in risk are beneficial. The response to PRA RAI 14 addresses the licensee action for implementing the changes in the HRA, if needed.
Electrical	21	Appendix A, General Design Criterion (GDC) 35, Emergency Core Cooling, to Title 10 to the Code of Federal Regulations Part 50 is only one of six GDCs that require onsite power. The others are GDC 33, Reactor Coolant Makeup, GDC 34, Residual Heat Removal, GDC 38, Containment Heat Removal, GDC 41, Containment Atmosphere Cleanup and GDC 44, Cooling Water which also require onsite power. Address the effect that a slow start and delayed loading of the EDGs would also have on the response of these systems and address the total effect on CDF.	Section 6.2.3 of this LTR addresses the impact on each of these GDCs. The cited GDCs do not impose as stringent design requirements as does GDC 35 on the affected equipment. The functions associated with the cited GDCs are not time-critical in the accident analysis such that the proposed relaxations in diesel start time (less than 2 minutes) would have a negative impact on their mission time. Therefore, we do not anticipate compliance issues with these GDCs as a result of the changes in the LTR. Each plant will confirm the impact of its proposed changes on its licensing basis with respect to the GDCs, since each plant's commitment to the GDCs is different.

Source	RAI #	Question	Response
T/H	1	A recent paper comparing calculations performed for a pressurized water reactor using MAAP and RELAP5, Park, C.H., Lee, D. Y., Lee, I. J. U. C., Suh, K, and Park, G. C., "Comparative Study of Loss-of-Coolant Accident Using MAAP4.03 and RELAP5/ MOD3.2.2," ICONE10-22439, Proceedings of ICONE10, Arlington, VA, April 14-18, 2002, noted that the same initiating event resulted in significantly different predicted sequences of events for a large break LOCA. One point in particular mentioned is that the break flows and emergency core cooling system (ECCS) flows were significantly different. Explain what is done to get "Approximately the same total break flow....," stated in Section B.4.2.1.	<p>The fundamental parameters of MAAP were not altered from the default values in order to achieve approximately the same break flow. The BWROG used the same break location and flow areas that are modeled in the standard SAFER/GESTR large break LOCA analyses for BWRs.</p> <p>As discussed in the meeting between the BWROG and NRC on February 14, 2006, and subsequent phone calls, it was not intended for the BWROG to review and comment on the cited papers. It is our understanding that they are cited only as background material.</p>
T/H	2	Large break LOCA analysis necessitates proper accounting for conservation of momentum. Provide the development of the conservation of momentum equation as applied in MAAP with detailed discussion of each of the following components: (1) temporal change of momentum, (2) momentum convection, (3) area change momentum flux, (4) momentum change due to compressibility, (5) pressure loss resulting from wall friction, (6) pressure loss resulting from area change, and (7) gravitational acceleration.	Follow-on discussions with NRC indicated that a formal response to this RAI was not required. It is well established that MAAP utilizes simplified break flow models and does not include all of the effects described in the RAI. The critical flow models in MAAP have been compared against several separate effects tests as described in the response to RAI 3 and show relatively good agreement. It is important to note that the simplified modeling tends to show wider variation with the test results only during the very early time periods of a LOCA and that longer term (greater than a minute) behavior tends to compare more favorably.

Source	RAI #	Question	Response
T/H	3	Provide code versus experimental data assessment cases for MAAP, including break flow, system depressurization, core flow, collapsed two-phase level, and ECCS injection. Assessment cases must include separate effects tests, component tests, integral systems tests, and plant data where available. The comparisons must also indicate the ranges of applicability of the experimental data for the large break LOCA in a BWR.	<p>EPRI has previously provided the NRC with the following documents:</p> <p>EPRI TR-100741, "MAAP Thermal-Hydraulic Qualification Studies"</p> <p>EPRI TR-100742, "MAAP BWR Application Guidelines"</p> <p>EPRI TR-100743, "MAAP PWR Application Guidelines for Westinghouse and Combustion Engineering Plants"</p> <p>The documents qualify the thermal-hydraulic models in MAAP for predicting system response during the early phases of a severe accident and assess the code's ability to model these phenomena. Comparisons to other codes, separate effects tests, integral tests and plant data are made with MAAP to identify any limitations using the code. Included in the referenced documents are MAAP comparisons to GE Small and Large Vessel tests, EPRI Valve Testing Program, Semiscale, FIST, RELAP, RETRAN and the GE SAFER code.</p>
T/H	4	Describe the MAAP CCFL model and provide assessment results.	<p>The MAAP model represents a channel quench front descending into the core. The basic assumption is that the rate at which the core spray can enter the core is governed by a counter-current flooding limitation. That is, the maximum rate at which water collecting above the core can enter is that rate at which water would just be flooded by the escaping steam. This rate is evaluated using the Kutateladze [1] equation as presented Fauske [2].</p> <p>References:</p> <p>[1] S.S. Kutateladze, "Elements of the Hydrodynamics of Gas-Liquid Systems," Fluid mechanics – Soviet Res., Ed. 1, Vol. 4, p. 29, 1972</p> <p>[2] H.K. Fauske, "Boiling Flow Regime Maps in LMFBR HCDA Analysis," Transactions of ANS, Vol. 22, pp. 385-386, 1975.</p>

Source	RAI #	Question	Response
T/H	5	The PCT responses provided in Figures B.4-5 and B.4-10 are clearly not the same event. Provide detailed thermal hydraulic comparisons. Include flow direction and mass flow rate, two-phase level, heat transfer regime and coefficient.	<p>The BWROG is not using MAAP as a surrogate for an Appendix K code for demonstrating compliance with 50.46. MAAP was used to determine the limiting case, then, TRACG was used to model the limiting case in detail to demonstrate mitigation capability. This was discussed with and acknowledged by the NRC reviewer subsequent to these RAIs.</p> <p>The two figures are the same event modeled in two different codes (MAAP and TRACG). The important results are the rate of heatup while the core is voided and the PCT and the time at which low pressure begins to inject. These comparisons also indicate that low pressure injection occurs at approximately the same times in the two codes as shown in Figures B.4-5 and B.4-10. The PCT predicted by MAAP is always higher than that predicted by TRACG, a conservative result.</p>
T/H	6	The TR indicates that for the BWR/4 a TRACG02 PCT adder of 193 °F is applied to a PCT of 1758 °F, while the BWR/6 the PCT adder of 212 °F is applied to 1422 °F. Justify these adders and provide for the uncertainty analysis.	During the preparation of the LTR, GE's TRACG04 model was under development. TRACG04 was being developed as a LOCA model. However, it could not yet be used for regulatory analysis. It was known that TRACG02, which was approved for regulatory analysis, had limitations in modeling LOCAs. GE required the application of the adders cited in the LTR to TRACG02 results as necessary to simulate PCTs comparable to those that would have been calculated by TRACG04.
T/H	7	In a study performed by the Josef Stefan Institute, Reactor Engineering Division, "Differences Between MAAP and RELAP5 Analyses of Large Break Loss of Coolant Accident," Technical Committee Meeting IAEA, Vienna, Austria, November 15-18, 1993, it was found that MAAP over predicted the reactor vessel liquid inventory when compared with RELAP5 by as much as a factor of nine. Please provide MAAP and TRACG comparisons of reactor vessel liquid level and inventory for the BWR/4 and BWR/6 cases in the TR.	As discussed in the meeting between the BWROG and NRC on February 14, 2006, and subsequent phone calls, it was not intended for the BWROG to review and comment on the cited papers. It is our understanding that they are cited only as background material.

D.3 ENCLOSURE 2: OUTLINE OF REVISED LTR

Title: SEPARATION OF LOSS OF OFFSITE POWER FROM LARGE BREAK LOCA

Legal Notice

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5.2.1. PRA Assumptions Used in Example Risk Impact assessment

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Appendix A: ECCS System Schematics

Appendix B: Thermal Hydraulic Analysis *(Same as current Appendix B, modified as needed)*

Appendix C: Example Application of Option 3 Changes *(Same as current Appendix C, modified as needed)*

Appendix D: Example of HRA Modifications

Appendix E: Responses to RAIs

D.4 ENCLOSURE 3: RESPONSES TO NRC COMMENTS ON EPRI TECHNICAL REPORTS 1009110, REVISION 1 AND 1007966 REGARDING THE ISSUE OF DOUBLE SEQUENCING NUCLEAR PLANT SAFETY LOADS

D.4.1 Introduction

In a letter dated September 24, 2004, the NRC Staff provided comments on the BWR Owners' Group (BWROG) submittal of April 6, 2004 relating to the Electric Power Research Institute (EPRI) Technical Reports 1009110, Revision 1 and 1007966 on the double sequencing issue. The BWROG appreciates the very thorough review effort completed by the NRC staff, and provides our planned resolution to those comments in the enclosure. The attached responses were developed by EPRI and reviewed by the BWROG.

These EPRI reports are the culmination of a project to establish a common and more comprehensive understanding of the double sequencing issue. Previously documented information on double sequencing is fragmented among many industry documents spanning a decade. The EPRI reports are intended to be 'living documents' that could be improved with additional experience and understanding of the double sequencing issue.

To that end, and in recognition that many of the NRC staff's comments can add substantially to the quality and completeness of the documents, EPRI intends to revise the two technical reports. The planned treatment of some comments is described in detail in this enclosure; in other cases our response simply acknowledges the need to expand the report discussions in areas affected by the comments.

The BWROG would like to highlight two specific comments. First, it is noted that Comment 4 pertains only to PWRs. The BWROG is providing a response to that comment since the EPRI generic document (EPRI 1009110) applies to both BWRs and PWRs. We have attempted to answer all questions without regard for reactor type and have provided some information that is clearly limited to BWRs. Second, NRC Comment 21 relates to the means by which PRA models can be adjusted to determine a rough estimate of the impact of double sequencing on core damage frequency. The comment touches upon the key double sequencing issue by indicating "If the vulnerabilities do not make the particular safety equipment unavailable altogether [emphasis added], the analysis should consider how the equipment failure rates would increase under the double sequencing scenario conditions and stresses." Redundant divisions being "unavailable altogether" for a common mode condition like double sequencing would represent an unacceptable consequence. This is the key consideration when evaluating the double sequencing issue. We believe that minor additional degradation related to equipment exposure to infrequent (and perhaps one-time)

conditions cannot be quantified and might very well be undetectable as to its impact on equipment reliability. Thus, minor accelerated aging degradation to equipment for a potential one-time event is not the substantive double sequencing issue.

EPRI Technical Report 1009110

1. Page 7-2, Item 8

With regard to the grid operator's plans and expectations for system performance following the trip of a nuclear unit, it is useful to understand that: the minimum switchyard voltage required by a nuclear plant that has no voltage regulating capability (such as auto tap changing transformers or static VAR compensators) is generally more limiting than the minimum voltage required to prevent a grid voltage collapse. The transmission system operator, therefore, cannot be relied upon to control a plant's post-trip switchyard voltage to the level that is necessary for the nuclear plant, unless the transmission operator has been made aware of the nuclear plant's requirements, and arrangements have been negotiated to control the switchyard voltage to that level, post-trip.

Response:

We concur with this comment. Note that Item 8 is one of ten considerations that bear on the estimation of a value for the probability-of-occurrence of a double sequencing event.

The NRC reviewers are correct in noting that, without prior negotiated agreements as to the pre-event voltage targets or schedule, those units without the post-trip ability to control plant bus voltage are more likely to experience a double sequencing event given identical configurations in all other respects. Note the last paragraph of Section 2.4 entitled Causes of Double Sequencing, wherein we state that the "initiators are more likely to occur if the grid and nuclear unit organizations are not closely coordinated both contractually and in their operations and communications protocol." Additionally, a firm agreement as to pre-trip voltage targets goes a long way to ensuring that nuclear unit (and grid) voltage will be adequate in the post-trip period without actions on the part of the grid operator.

The closing sentence of Item 8 states "Adherence to these guidelines minimizes the likelihood of double sequencing." The guidelines are those of Generic Letter 79-36, which cannot be reasonably satisfied without installed voltage regulation equipment, large voltage margins in the plant's design or close coordination with the transmission

system operators. There is a Branch Technical Position (BTP) that includes similar guidelines for the more modern nuclear units to which the BTPs applied.

Based on the above, we propose to make no change to the document as a result of this comment. It is our intent that the users of the document consider all items listed in this section in arriving at their own estimation of the probability of occurrence of a double sequencing event at their nuclear unit(s). Clearly, a "loose" interface with the grid operators will, for nuclear units without the benefit of automatic voltage regulating capability, contribute to a higher likelihood of occurrence of a double sequencing event.

2. Page 7-3 – Sentence immediately following Item 10

"Best estimate LOOP [loss of offsite power] frequency" is not the important parameter for LOCAs [loss-of-coolant-accidents]. The important parameter for LOCAs is "conditional LOOP probability given a LOCA." This is the parameter that should be determined for LOCA initiators including degraded voltage situations.

Response:

We concur that the use of the term "best estimate" is inappropriate and plan to change the affected sentence to read "The above guidelines should assist the user in determining the probability of occurrence of a degraded voltage-induced LOOP."

It is our intention to more definitively identify double sequencing as an event that can only occur subsequent to a safeguards system actuation whether that actuation is real or spurious. In this regard, the probability of occurrence of a double sequencing event will always be preconditioned by a safeguards actuation. Thus, the term "double sequencing" has no meaning as a potentially limiting condition except when coupled with a safeguards actuation. While a spurious actuation followed by a double sequencing condition will not be the most limiting event since it will be far more time-forgiving relative to operator response, it will expose safeguards equipment to the operational anomalies that accompany the double sequence condition.

We will revise section 7-1 wherein the term "best estimate" is used in a few instances to eliminate the word "best".

3. Page 7-3 – Partial paragraph immediately following above sentence

With regard to the statement, "While a LOOP is not likely to cause a LOCA," it is noted that a LOOP that results in a full-load rejection of a nuclear plant's turbine generator has some potential to cause a LOCA due to stuck-open safety or relief valves.

Response:

We concur with this comment and will revise the sentence to read, "While a LOOP is not likely to cause a LOCA having greater significance than a post-trip stuck open safety or relief valve, a LOCA may under some circumstances result in a LOOP."

TMI lessons learned and changes incorporated thereafter have vastly improved the operators' ability to detect and effectively mitigate the impact of a stuck valve scenario. However, this clarification of our statement helps to ensure that the evaluation of the impact of double sequencing on "stuck open valve" isolation equipment (mainly MOVs) is not overlooked.

4. Page 7-3 – Last bullet on page

With regard to the sentence that reads, "The delay in tripping the turbine is nominally about 30 seconds, however the reverse power relays usually operate considerably sooner and trip the generator." The beginning of that sentence should read, "The delay in tripping the generator is ..." Also, it is our understanding that Westinghouse plants and some other pressurized water reactors (PWRs) utilize 30 second time delays only and do not necessarily utilize reverse power relays to trip the generator and transfer loads (reactor coolant pump shaft seizure event credit).

Response:

This comment, in part, corrects our reference to the "turbine" when it should have stated the "generator". We will make this correction.

Regarding the 30 seconds time delay in tripping of the generator when mechanical and/or electrical faults are not present in the turbine generator lineup, we note that there may not be a consistent position across the PWR spectrum on this issue. A 30 second delay in tripping will cause the main generator with attached turbine to motor for several seconds. This is an undesirable condition that, at the very least, is to be minimized in terms of its frequency of occurrence. In the case of some units, protective relays, usually of the reverse power type, operate in parallel with the 30-second timer. Depending on the time setting selected for these relays, they may or may not operate faster than the 30-second timer, which, in some cases, may be caused to start timing by the detection of a reverse

power condition by a separate relay.

Our discussions with Westinghouse experts revealed that their reasons for avoiding an immediate trip of the generator when conditions permit relates to the departure from nucleate boiling (DNB) advantage of maintaining forced (versus coastdown) flow from the reactor coolant pumps for at least a few seconds for a reactor trip following a Steam Generator Tube Rupture (SGTR) event.

Documentation was provided by Westinghouse indicating a minimum requirement for 2 seconds retention of forced reactor coolant flow in the case of the KORI units (3 and 4) following a SGTR event-induced unit trip. This event is most limiting as it relates to the need for a short period of forced coolant flow following the reactor and turbine trip.

We agree that the reverse power trip of the main generator has been stated with too high a degree of certainty in our report since there are variations on this trip scheme across the industry. We will likely revise the affected sentence to read "The delay in tripping the turbine is nominally set at 30 seconds; however, there are a variation of design arrangements across the PWR spectrum. For this reason, we will amend the document such that licensees choosing to use the guidance contained herein receive a clear message that they need to understand their specific unit designs.

We note that the last sentence in the section commented on already stresses the usefulness of understanding the extent of trip delay and we remain convinced that having that knowledge will help to more fully understand the manner in which the double sequencing event would evolve. This generator trip timing discussion is of more significance to those units that normally power their safeguards buses from the unit auxiliary transformer and have either an installed generator breaker or utilize a high-speed transfer actuation to switch to their preferred offsite power source. At issue here is the likely timing of occurrence of a degraded voltage condition that leads to a double sequencing event, since it is highly unlikely that a degraded voltage condition will occur and persist when loads are powered from the main generator-connected unit auxiliary transformer.

5. Page 7-4 – Second bullet on page

With regard to the sentence that reads, "High-speed transfer schemes have historically functioned very reliably," NRC report AEOD/E-93-02 and EPRI Advanced Light Water Reactor [ALWR] Requirements Document for the ALWR Evolutionary Plant, Chapter 11, indicate that high speed transfer schemes have not functioned very reliably.

Response:

We concur that from some aspects and on a statistical level, high-speed transfer schemes can be shown to "have not functioned very reliably." However, for events at domestic nuclear units resulting in either a full or partial loss of offsite power, high-speed transfer schemes have not been a large contributor to these losses. EPRI Technical Report 1002987, entitled *Losses of Off-Site Power at U.S. Nuclear Power Plants Through 2001* was reviewed to arrive at this conclusion. EPRI's document lists some 149 full or partial loss of power events occurring between the years 1990 and 2001. Of these, five events can be shown to have at their root, a failure of a high-speed transfer scheme. Some of these are due to now corrected design or system operating errors. Another four events can be remotely tied to high-speed transfer scheme operation. These events generally resulted in proper scheme operation to prevent a transfer to offsite power for reasons quite apart from failures within the transfer schemes.

Conservatively counting all nine events as high-speed transfer failure-initiated events, one arrives at a 6% contribution to all loss of offsite power events (during the period studied) being caused by high-speed transfer schemes. This is not to be confused with a 6% failure rate for high-speed transfer schemes since the many times that they operate correctly are not reported in a manner that can be readily retrieved. We recognize that not all nuclear units use a high-speed transfer of safeguards buses since several are normally powered from their startup auxiliary transformers while others utilize a generator breaker that allows the unit auxiliary transformers to remain energized even if the main generator is not operating. For this reason, the contribution of high-speed transfer schemes to LOOP events is only roughly estimated here.

We note that significant improvements have been made in maintenance practices driven by both internal industry initiatives and NRC actions (like the Maintenance Rule). These improvements serve to render historical high speed transfer failure data useful in only a very conservative sense. Additionally, and as noted above, some failures served to reveal defective transfer actuation scheme designs which were then fixed and most likely made known to the entire industry to investigate via the now available Operating Experience-related processes.

The important point being made in the report is that high-speed transfers, when they occur, do so sufficiently fast as to cause no undue stress on the equipment being transferred. Therefore, to the double sequencing issue, high-speed transfer reliability is a rather moot point, as it does not represent a worst case. A failure of the transfer would, in the case of most domestic nuclear units, result in safeguards loads being powered by the onsite emergency generators.

Since our statement can be misinterpreted in a non-conservative manner, we propose to change the wording in the report from "High-speed transfer schemes have historically functioned very reliably." To "High-speed transfer schemes have not historically been a major contributor to loss of offsite power events nor have they been demonstrated to unduly stress transferred loads."

~~6.~~ Page 7-5 = First three bullets on page.

The assumptions of these three bullets is that as long as the duration of safety system deenergization is small compared to the capabilities of the batteries (1-hour useful discharge life), double, triple, or even quadruple sequencing would not affect the batteries capability. The margin that is believed to exist on the batteries is not as large as assumed here. The first one-minute loading on batteries that is due to load sequencing is almost always limiting. The battery voltages during this period are pulled down very close to the minimum required voltages of the loads due to current inrushes of loads like circuit breaker charging motors. Although the battery may have one or more hours capacity at much lower current demands, a substantial amount of capacity does not have to be discharged before it cannot meet the limiting load sequencing requirement. The battery ~~may not be capable of providing two, three, or four load sequencing repetitions if the charger is not available due to low input voltage or late sequencing on the emergency diesel generator (EDG).~~

Response:

The one-minute load peak period of a nuclear unit's battery loading profile is a conservative modeling technique used to envelope the numerous very short demands on the batteries during the first moments of a worst case battery loading event. These demands, like multiple and only slightly time separated breaker operations (and subsequent operating spring recharging operations) are spread out over a time period assumed to not exceed one minute in duration. We concur that a station battery's size is oftentimes dictated by the voltage drop experienced during this short duration of peak loading, but also realize that it is the reapplication of this one minute load at the tail end of the Station Blackout (SBO) coping period (when the battery is significantly discharged) that is often most limiting. A double sequencing event without a SBO event (by definition, there will not be a SBO event) will not remove meaningful capacity from a battery even when assuming that the battery charger makes no contribution to the supply of DC System demand. We estimate that a second one-minute peak in the early seconds or minutes of an event will not be voltage limiting either, as insignificant battery capacity has been expended at that point and far fewer breakers will require tripping. We refer to those breakers that, upon a LOOP event, serve to remove from safeguards buses all non-

essential post-LOCA loading.

However, we concur that the document should not serve to relieve the users of the requirement to determine that the above is or is not the case for their unit(s), and will revise our notes, accordingly. The words "triple or even quadruple" will be removed since they have no relevance to the double sequencing issue and serve to project a sense of overconfidence relative to the ability to generically address this DC System issue. Also, while most but not all nuclear units have a 125 VDC system, some units employ a different voltage level. We will acknowledge this detail in our revised discussion.

We note that for BWRs, the more significant DC bus loading in terms of impact on the battery is that of the DC MOVs used in the design.

Your Comment 6 is closely tied to Comments 9 and 14. Accordingly, our responses to these comments refer to this response.

7. Page 7-6 – Table 7-1, Item 1 and its associated Note 1

This item evaluates 4kv motor and control switchgear buses and breakers from a loading duty cycle perspective, but that is not the limiting case for double sequencing. An evaluation should be performed of the circuit breaker (CB) anti-pump logic and load sequencing logic for the double sequencing scenario. Actuation of CB anti-pump logic due to double sequencing can result in a trip and lockout of CBs feeding safety equipment. CB anti-pump logic designs that recharge CB closing springs following a trip of the CB are especially vulnerable, but all CB anti-pump designs are vulnerable to some degree. Such vulnerability was identified at Indian Point 3 in April 5, 1994, letter to the NRC. NUREG/CR-6538 provides additional background on CB anti-pump logic vulnerabilities during double sequencing.

Load sequencing logic that is not specifically designed for double sequencing can result in overloading emergency diesel generators (EDGs) due to failure to load shed previously sequenced loads during double sequencing, paralleling the EDG out-of-phase with motor residual voltages, and/or it can simply result in lockup of the sequencer. Additional information on these load sequencing vulnerabilities can be found in NRC Information Notice 92-53, "Potential Failure of Emergency Diesel Generators Due to Excessive Rate of Loading," and NUREG/CR-6538.

Response:

We concur with the breaker anti-pumping comment and will revise the document to

ensure that the user is aware of the need to complete a unit-specific review of that circuit's design and ability to function properly during a double sequencing evolution.

Regarding the load sequencing logic comment, a properly designed load sequencer must have the ability to function correctly in the long-term post-LOCA during which period a LOOP has always been deemed credible. A design that allows an emergency diesel generator (EDG) to become overloaded and/or damage itself and/or its loads due to an out-of-synchronization breaker closure is inappropriate and requires correction. A sequencer design that works properly in the long-term post-LOCA should work equally properly in the near-term post-LOCA. Nevertheless, our revisions will include references to NUREG-6538 and the related NRC Issue 171 since these can be helpful to users of the double sequencing documents.

8. Page 7-6 – Table 7-1, Item 2 and its associated Note 2

This item evaluates 4kV protective relaying. It only evaluates electro-mechanical induction disk time-overcurrent relaying. IEEE Standard 741-1997 identifies solid state overload (SSO) relays with thermal memory capability that have been used on the motors of motor-operated valves (MOVs). If these relays are also used on 4 kV motors, it provides a greater potential that the relay will trip during double sequencing because the relay is not completely reset back to zero following the first start of the motor. This is the case for any motor-current overload protective device that utilizes a thermal memory capability, e.g., thermal overload (TOL) protective devices in motor starters.

Response:

We concur that our Note 2 explanation using induction disk type time-overcurrent relays as the example too narrowly focuses on one relay type and does so without consideration for load inertia. The document will be revised accordingly, likely recommending that licensees review limiting cases. Motor overload protection is intended to mimic as closely as reasonably practical, the motor being protected and to do so with a degree of non-conservative motor protective margin (i.e., the motor needs to be in a sustained overloaded or locked rotor condition to cause the protection to operate). Thus, both load inertia and the thermal overload protection memory feature require consideration. We note that overload protective device thermal memory is one element involved in more closely mimicking motor performance in that a motor is similarly unable to immediately cool down following its deenergization.

Also related to the above as well as your Comments 18 and 20, and a topic that we need to address in a future document revision, is the manner in which short duty cycle rated

motors like those used to power ac-powered MOVs are protected. The thermal overload selection process for these results in the specification of a device that cannot support continuous operation of the short duty cycle rated motors, since the motors would not be protected against too long a run if that were not the case. Thus, a motor requiring 10 amperes of running current might have a thermal overload device rated at 7 amperes. Note that the ampere values used represent a roughly estimated example case presented only to make our point here.

9. Page 7-6 – Table 7-1, Item 3 and its associated Note 3

This item evaluates 4kV 125Vdc control power. Note 3 concludes that control power for the metal-clad 4kV switchgear at most, if not all units, is supplied by a 125Vdc battery system and is therefore not subject to the effects of double sequencing. Comments 6 and 7 above apply.

Response:

Our responses to Comments 6 and 7 above relative to the 125 VDC systems also apply to this comment.

10. Page 7-6 – Table 7-1, Item 4 and associated Note 4,

a) This item evaluates 4kV pump induction motors, however, Note 4 states that the discussion is also applicable to motors of other sizes and voltage rating since the 4kV large motor case is bounding and thus applicable to Items 5, 11, 12 and 16 in the listing of evaluated components. The 4kV pump induction motor case does not necessarily bound Items 5, 12, and 16; this is actually implied in Table 7-1 itself. The table lists the "Level of Impact" for Item 4 (the 4kV pump motor case) as "None," whereas Items 5, 12, and 16 are listed as "Negligible." The reason for the difference in Items 5 and 12 is likely due to the fact they are fan motors, rather than a pump motor like Item 4. Fans have a much higher moment of inertia than the typical pump; and, as a result, they take much longer to come up to full speed.

This means there is more motor heat-up during the start and potentially less margin between motor torque capability and the fan load torque requirement. This concept is described in the Note 4 discussion of PWR reactor coolant pump high inertia flywheel loads that are not subject to double sequencing, but is not discussed for the high inertia safety-related fan motors that are subject to double sequencing. Neither Tables 7-3 nor 7-4 under Note 4 provide any data on fan motors. This information should be provided as well as an evaluation of the effects of double sequencing on the fan motors. It is noted

that Recommendation 1 in Chapters 9 and Key Recommendation 2 in Chapter 1 both recommend that fans be more thoroughly reviewed by plant engineering motor specialists. Fans and their motors, however, should be specifically evaluated in this EPRI report, rather than leaving it to the individual plants, since they may be the most limiting electrical motors under double sequencing conditions.

Response:

Regarding motor/load inertia and the impact of double starts on motor integrity, we concur that our document needs to evaluate a few fan-loaded motors at a minimum. Our recommendation that users evaluate bounding fan load cases will likely remain, however, as it may not be possible for the BWROG to identify a bounding typical case. It is appropriate to provide a sampling of results, however, and we will strive to obtain the necessary detailed information from the owners of the pilot units studied or from a BWR plant if a more limiting case is identified there.

b) Note 4 discusses Section MG1-20.43 of NEMA MG1 Standard, entitled "Number of Starts." It states that properly specified and designed motors for nuclear power plants satisfy the specified conditions for applied voltage. What the Note misses and does not discuss is the good likelihood that the double sequencing of the motors will be due to actuation of the degraded voltage relays due to inadequate switchyard voltages as a result of the loss of the plant's generator MVAR support to the grid. Under these conditions, the applied voltage is not adequate. The first start of the motors will be a prolonged start under degraded voltage conditions with substantial preheating of the motor during the start. The second start of the motors on the EDGs could also be considered somewhat of a degraded start under the NRC Regulatory Guide (RG) 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," specified minimum voltage of 75 percent and frequency of 95 percent. Section MG1-20.45 of the NEMA MG1 standard specifies an applied voltage of plus or minus 10 percent of rated voltage, with rated frequency. Under the degraded voltage condition discussed, the applied voltage will not meet the minimum specified voltage in MG1-20.45; and as a result will not meet the requirements in MG1-20.43 for two starts in succession. This should be discussed in Note 4. It is noted that in Section 2.3, page 2-3 of the report, there appears to be no acknowledgement that switchyard voltage could drop immediately following the trip of the plant's generator due to the loss of the generator's MVAR support to the grid. This should be addressed in Section 2.3.

Response:

Regarding the potential that the first start of critical motors will be attempted with a degraded voltage (less than 90% of motor rating) applied, we will add discussion advising users to evaluate a bounding case using the minimum voltage which could persist for the duration of their second level undervoltage relay time delay. We note that safety related motors for the pilot units were specified for purchase with an ability to start loads with a minimum of 80% (and in some cases, 70%) of rated voltage applied. Our document revisions will provide advice to licensees to consider any better than standards-specified capability that they may have built into the nuclear units.

Judgment should be exercised in this area, realizing that hypothetically, a worst case could be defined as one having the lowest level of voltage without protection (the first level undervoltage relay setting) for the maximum time duration (the time delay setting for the second level undervoltage relay).

From a probabilistic standpoint, however, it is highly unlikely that this will be the case. With the very small degraded voltage-to-operating voltage margins that exist at most nuclear units, the most likely degraded voltage scenario is one wherein voltage falls only marginally below the second level undervoltage relay setpoint. Just as likely, following large motor starts, bus voltage might return to a level above the setpoint but not sufficiently above that level to reset the dropped out voltage detection device(s). When small margins are involved, such issues as relay drop-out-to-pickup ratios become an issue. Your comment reveals the need for more discussion in our document in this area. Our revisions will seek to provide guidance as to a means for calculating a degree of voltage degradation that is both conservative and reasonable.

We do not agree that emergency diesel generator (EDG) starts of motors should be viewed as degraded, even though allowed momentary voltage and frequency swings are significantly outside of NEMA MG 1 limits. Experience shows EDGs to be excellent suppliers of stand-alone power for the starting of motors. This is due to the use of automatic voltage regulators and dynamic governors that serve to rapidly restore voltage and frequency to the set targets. For that reason, unless we identify evidence to the contrary, we will continue to consider the second start of equipment to be under normal power supply conditions.

Regarding the lack of mention in Section 2.3 "that switchyard voltage could drop immediately following the trip of the plant's generator due to the loss of the generator's MVAR support to the grid," we note that an immediate drop, while likely, would not represent a worst case since the second level undervoltage relay timers would likely start immediately as opposed to being delayed in their start, a condition which we believe does represent the worst case. We agree that a worst case for one condition (an untimely

interruption in coolant injection flow) may not be a worst case for another condition (like the first start of motors occurring with a degraded voltage). The vast number of combinations and permutations for event development makes the use of judgment in some areas unavoidable. We will include some discussion on this subject in both Section 2.3 and when specifically addressing motor starts.

- c) - On page 7-9 of the report, Note 4 states that motors are nominally designed for a life of from 20 to 40 years and, in many applications have, with reasonable preventive maintenance, lasted significantly longer than the design life. Note 4 should acknowledge that the majority of plants will be operating for 60 years under license renewal and address the consequences of this on motor design life.

Response:

We concur with your comment and note that individual nuclear unit owners will always have the responsibility for evaluating the impact of life extension initiatives on their equipment using available guidance such as this double sequencing document. We will revise the report to acknowledge the likelihood of most plants operating for 60 years and provide some of the generic reasons why motors may be acceptable for life extension given their relatively mild service environment, low number of starts, routine preventive maintenance etc.

d) On page 7-11, Note 4 references Table 7-3 data from Millstone and states that sizeable safety margins are evident between the inertia the motors could accelerate to rated speed and the inertia of the actual plant loads. Are the actual plant load inertias provided in Table 7-3, the inertia with the pump discharge valves initially in the closed or open position? During double sequencing, the first pump start will typically be with the pump discharge valves in the closed position resulting in low load inertia; but during the second pump start the valves will likely be in the fully open position resulting in high load inertia. This issue was identified during an Advisory Committee on Reactor Safeguards (ACRS) hearing on delayed LOOP, and the ACRS indicated that the design of the pumps generally only provide for starting of the pump against a closed discharge valve.

Response:

NRC is correct in alluding to the fact that the motor's output capacity (torque) will, in part, be consumed by accelerating and moving the pumped (or compressed) media if a valve (or damper) is open, and flow allowed. Regarding safety margins between load and motor torque requirements and capability, respectively and the issue of pump starts with discharge valves in the wrong position, we note that a properly designed pump motor

start control circuit includes interlocks to preclude starts under incorrect discharge valve lineups when valve position is important.

A Service Water Pump (SWP) at one of the pilot units is a good example for discussion and will be considered for inclusion in the report. In this case, SWP motor starts are supervised by valve position; i.e., the start circuit is not satisfied without the valves first returning to their required position. A shutdown of the motor whether manually or by way of a LOOP-induced trip, is followed by automatic valve repositioning prior to its restart permissive being satisfied.

Finally, while we agree that load inertia is a factor that affects acceleration time, it is the BWROG's position that "built-in" inertia (like that presented by the mass and diameter of a large fan blade set) represents the greatest opposition to acceleration during the lowest motor torque capability rotational speed region. We note that the load, air in this example case, presents a resistance to acceleration (inertia) that is not in any respect directly proportional to fan speed, but rather, is considerably less than directly proportional. In fact, as the motor and fan approach operational (rated) speed, the induction motor finds itself with its greatest operational torque capability since it is in the "pull-in" torque region of the associated torque versus rpm curve. While we believe that this consideration markedly reduces any concern related to "load" induced inertia, we will none-the-less speak to this point in our revisions to the document(s).

11. Page 7-6 – Table 1, Item 5 and its associated Note 4

This item evaluates 4kV fan motors. Comment 10a above applies.

Response:

Our response to Comment 10a applies to this comment as well.

12. Page 7-6 – Table 7-1, Item 8 and its associated Note 7

This item evaluates 480V load center switchgear and breakers. Comment 7 above applies to 480V breakers that are load sequenced.

Response:

Our response to Comment 7 applies to this comment as well.

13. Page 7-6 –Table 7-2, Item 10 and its associated Note 9

This item evaluates 480V load control center switchgear and breakers. Comment 7 above applies to 480V breakers that are load sequenced.

Response:

Our response to Comment 7 applies to this comment as well.

14. Page 7-6 – Table 7-2, Item 10 and its associated Note 9

This item evaluates 125Vdc control power for 480V load control centers. Comment 6 above applies.

Response:

Our response to Comment 6 applies to this comment as well.

15. Page 7-6 – Table 7-1, Item 11 and its associated Note

This item evaluates 480V load center powered pump motors. The number of the note associated with it appears to be in error. The staff believes Note 4 was intended. Comments 10a, b, c, and d above apply.

Response:

We understand that the equipment numbers in the Table are not appropriately indexed to the notes. In addition to correcting this overall condition, we will also correct the note numbering error that you have identified when we revise the document. Our responses to Comments 10a, b and c apply to this comment as well.

16. Page 7-7 – Table 7-1, Item 12 and its associated Note 4

This item evaluates 480V load center powered fan motors. Comment 10a above applies.

Response:

Our response to Comment 10a applies to this comment.

17. Page 7-7 – Table 7-1, Item 13

This item evaluates 480V motor control centers molded case circuit breakers. No note is associated with this item, but it appears Note 10 was intended to apply.

Response:

We will correct this omission.

18. Page 7-7 – Table 7-1, Item 14 and its associated Notes 10 & 11

This item evaluates 480V motor control center protective relaying. It appears that only Note 11 applies to this item and Note 10 was intended to apply to Item 13. Note 11 states that double sequencing will not cause improper operation of thermal overload protectors if these relays are set in accordance with standard industry practice. The staff does not believe this is necessarily true, particularly if the double sequencing is due to degraded voltage. Comment 10b above discusses the degraded voltage scenario. The double sequencing, in combination with the prolonged inrush current during the first degraded voltage start, could cause actuation of thermal overload protectors due to the excessive pre-heating of the thermal element during the first start. Comment 8 above also applies.

Response:

We will correct the notation error. The document will be expanded to cover this issue and the potential need for unit-specific sensitivity checks of bounding motor/load thermal overload combinations. Our response to Comment 8 is closely related to this comment.

19. Page 7-7 – Table 7-1, Item 17 and its associated Note 13

This item evaluates 480V MOV reversing and non-reversing contactors. The associated Note 13 addresses the high continuous inrush current that can flow to the coils of motor starters during a sustained degraded voltage condition. It describes fuse blowing experiment results at Millstone that found properly sized fuses remained intact with inrush current flowing from 40 to 60 seconds. Degraded voltage relay time delays have typically been chosen to be short enough to preclude the fuses from blowing, but did not consider the second additional short reenergization and inrush that would occur during double sequencing initiated by a degraded voltage condition. Degraded voltage relays, particularly those with longer time delays, should be evaluated to ensure the second reenergization will not blow the fuse.

Response:

We concur with your observation that most second level undervoltage time delays have been selected to be sufficiently short to avoid the potential for blowing control circuit fuses due to the sustained inrush current demand of a starter contactor that has insufficient voltage to pick up. However, lacking assurance that this is the case across the industry, we will add a reminder that fuse sizing criteria and second level undervoltage time delay need to be evaluated on a unit-specific bounding case basis.

We do not, in general, agree that the second contactor pickup demand has the potential to blow the fuse even if only minor fuse opening margin remains after the first attempt. This is due to the fact that a contactor, when energized with acceptable voltage (which it will have on the second position change demand) changes state in a matter of a few electrical cycles, at most. A second pickup demand occurring simultaneous to a voltage dip caused by a large motor start would, at most, expose the contactor and fuse to a few second period of inrush current. We will discuss the need to consider this potential in our revisions to the document.

20. Page 7-7 – Table 7-1, Item 18 and its associated Note 14

~~This item evaluates short duty cycle (15 minute) motors. The associated Note 14 states that even in the most severe applications, several strokes from one position to the other can be completed without violating the 15-minute criteria. The Note does not address double sequencing that is initiated by a degraded voltage. In this scenario, the MOV motor inrush and operating cycle during the first degraded voltage start can be excessively long since the motor torque is a direct function of the applied V^2 . During the second sequence, if the MOV has not fully cycled, there will be a second motor inrush. This could potentially trip the motor overload protection and should be evaluated. Comment 18 above also applies.~~

Response:

This comment and Comments 12d and 18 relate to the type of motors used to power Motor Operated Valves (MOVs). We agree with your observation relative to prolonged starts and the potential to trip the thermal overload. Our report will be modified to note that for nuclear units wherein the thermal overloads are not bypassed either full time or upon occurrence of an accident event per NRC guidance, a review of a bounding case will be necessary to determine if the thermal overload is appropriately sized.

21. Page 9-2 – Recommendation 5

This recommendation provides guidance on how probabilistic risk assessment organizations can use the EPRI report and any input from their safety analysis personnel to determine if there is a need to update probabilistic safety analysis models to include double sequencing. It indicates that increasing the failure probability of the diesel generators and the grid-related LOOP initiating frequency are two approaches to modeling the risk impact of double sequencing in plant-specific probabilistic risk assessment (PRA) models, and those can easily be implemented in the nuclear plant equipment out-of-service computer program. The staff does not agree with this view and would reject an analysis that used only these approaches.

NUREG/CR-6538, "Evaluation of LOCA with Delayed LOOP and LOOP With Delayed LOCA Accident Scenarios," found that in 1997 nuclear plant individual plant evaluations (IPEs) do not model nor do they discuss LOCA with consequential or delayed LOOP. Increasing grid-related LOOP initiating event frequencies in plant-specific PRAs or EOOS programs would therefore provide no insight into the risk impact of double sequencing scenarios, but would only indicate the risk impact of station blackout scenarios which are typically the events LOOP frequencies are used for. In fact, LOOP initiating event frequency is not the parameter of interest in double sequencing scenarios (see Comment 2, above). Conditional probability of LOOP given a LOCA, or consequential LOOP for short, is the parameter of interest. This is supported by the discussion in Section 1.1 of the EPRI report under the topic of "Probability of Double Sequencing at Domestic Nuclear Power Plants." A comprehensive discussion of consequential LOOP can also be found in Appendix G of a July 31, 2002, NRC Office of Research memorandum located in the NRC Agencywide Documents Access and Management System (ADAMS) at Accession No. ML022120661.

Increasingly the failure probability of the diesel generators, which is the second proposed approach, is only a portion of the vulnerability of double sequencing scenarios. A PRA should consider the other equipment vulnerabilities addressed in the EPRI report as amended by the totality of these NRC comments. If the vulnerabilities do not make the particular safety equipment unavailable altogether, the analysis should consider how the equipment failure rates would increase under the double sequencing scenario conditions and stresses.

Response:

There are many points for discussion relative to this comment. Regarding the approaches to PRA adjustment that we suggested, we concur that, if it cannot be shown that double sequencing will not increase the likelihood of failure of accident mitigation equipment, these approaches are not the right ones. Our view of this matter is that minor additional

degradation related to equipment exposure to infrequent and perhaps, one-time conditions cannot be quantified and might very well be undetectable as to its impact on equipment reliability. We believe that the revisions to this document occurring as a result of your comments have the potential to change the NRC's outlook as to the acceptability of the proposed PRA approach. It is also possible that our work involved in revising the document as a result of your comments will result in a change to our proposed approach.

It is key, however, that licensees be able to confidently establish that a double sequencing event will not invalidate compliance with the single failure criterion for a common mode condition; i.e., double sequencing. In most cases, redundant and independent equipment divisions are identically designed and constructed. As an example, if a double sequencing event causes a fuse of proper size and in proper condition to blow in the MCC control circuit of a Train A critical MOV control circuit due to the inability of its starter contactor to pickup, then it is logical that it will blow the fuse in the Train B MOV circuit as well. Your reviewers say it well in the last paragraph of this comment wherein they state that "If the vulnerabilities do not make the particular safety equipment unavailable altogether [emphasis added], the analysis should consider how the equipment failure rates would increase under the double sequencing scenario conditions and stresses." ~~Redundant divisions' being "unavailable altogether"~~ is a condition that would be unacceptable and is the key consideration for evaluation when addressing the double sequencing issue. Minor accelerated aging type of degradation to properly maintained equipment for a potential one-time event is not the substantive double sequencing issue.

Regarding the issue of "conditional probability" and as noted earlier in our responses, we will refrain from using that terminology since a double sequencing event can only occur if there is a safeguards actuation and otherwise has no meaning.

EPRI Technical Report 1007966

1. General

The comments provided for EPRI Report 1009110, Revision 1, "The Probability and Consequences of Double Sequencing Nuclear Power Plant Safety Loads," apply equally to this report and boiling water reactors (BWRs) in general, since the electrical equipment in BWRs is not substantially different from pressurized water reactor designs.

Response:

We agree that, with minor exceptions, the NRC's comments on the more comprehensive Report 1009110, Revision 1 are equally applicable to BWRs. An example of one

exception is the discussion of the 30-second time delayed trip of the main generator in PWR plants included in your Comment 4.

We note that, while much of the basic equipment is similar if not identical, and could have been installed in a PWR or a BWR, the BWR design inherently requires a much smaller subset of equipment to operate to mitigate the consequences of the entire range of design basis accidents.

2. Page 7-3 –Discussion in Section 7.4

In this discussion it is indicated that BWR/6 designs have additional margin and are less affected by double sequencing because they have a dedicated diesel generator for the HPCS system. It is not clear if these conclusions recognize that the HPCS is normally powered from offsite power and is powered from its diesel only when offsite power is lost. It is therefore subject to energization and reenergization similar to double sequencing. There is also at least one BWR/6 plant that has a short sequence of an HPCS pump and a cooling water pump on the HPCS diesel generator, which would make it even a bit more like the double sequencing designs.

Response:

We will research this comment and revise the document as appropriate.

APPENDIX E

**EXAMPLE CALCULATION OF PLANT-SPECIFIC PROBABILITY OF
CONDITIONAL LOSS OF OFFSITE POWER GIVEN A LOCA**

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E.1 EXAMPLE

The following is provided as an example for calculating the conditional probability of LOOP given a LOCA. Reference E-1, Appendix G provides a method for developing a generic value for the conditional probability of LOOP given a LOCA. In this method, the causes of consequential LOOP given LOCA are divided into two parts, plant-centered factors and transient (grid-related) factors. The probabilities of LOOP given LOCA from each of these two factors is summed to produce the total probability of LOOP given LOCA, as follows:

$$P(\text{LOOP given LOCA}) \approx P(\text{LOOP due to plant-centered factors}) + P(\text{LOOP due to transient factors})$$

as long as the probabilities on the right side of the equation are both less than 0.1; otherwise, this approximation is not accurate.

Plant-Centered Factors

The fault trees presented in Figures E.2-1 and E.2-2 are derived from Reference E-1, Appendix G-1 and represent generic models for calculating the conditional probability of LOOP given a LOCA due to plant-centered factors for two different plant configurations. Configuration #1 supplies power to the safety buses from the main generator through an auxiliary transformer, Configuration #2 supplies power to the safety buses from offsite power through a startup transformer, during normal operation. The failure rates used to quantify these fault trees is presented in Table E.2-1.

If the licensee chooses to develop its own plant-specific probability of LOOP given LOCA, licensee should develop its own fault trees, based on plant-specific design considerations and use plant-specific failure rate data where available.

Transient Factors

Reference E-1, Appendix G uses the plant-centered probability of consequential LOOP given LOCA as bounding estimate of the probability of consequential LOOP given LOCA due to transient factors, as described in Section G.4.2. The previous equation for the total probability of consequential LOOP given LOCA reduces to the following:

$$P(\text{LOOP given LOCA}) = 2 * P(\text{LOOP due to plant centered factors})$$

E.2 REFERENCES

- E-1. USNRC, "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10 CFR 50.46/GDC 35," Revision 1, July 2002.

Table E.2-1
Failure Rate Data Used to Calculate Generic Value for P(LOOP given LOCA)

Fault Tree Basic Event	Description	Failure Probability
AUTOTAPCHGRBADV	Automatic tap changer yields Inadequate voltage	2.00E-04
AUTOTAPCHGRRLYFL	Inadequate voltage from tap changer due to defective relay	1.40E-03
BATTERYBETA	Beta factor for batteries	9.90E-03
CKTBRKRBETA	Beta factor for circuit breakers	3.80E-02
CKTBRKRBUSAFTC	Incoming circuit breaker feeding bus A fails to close	8.60E-03
CKTBRKRBUSAFTO	Outgoing circuit breaker feeding bus A fails to open	1.60E-03
CKTBRKRBUSBFTC	Incoming circuit breaker feeding bus B fails to close	8.60E-03
CKTBRKRBUSBFTO	Outgoing circuit breaker feeding bus B fails to open	1.60E-03
CKTBRKRFTC	Independent failure of circuit breaker to close	8.60E-03
CKTBRKRFTO	Independent failure of circuit breaker to open	1.60E-03
MAINGENRLYFAIL	Failure of relay of main generator output breakers	5.60E-03
RELAYBETA	Beta factor of relays	6.00E-02
SECONDLINEFAIL	Loss of second line given failure of first line	1.00E-01
STARTUPXFFAILS	Startup transformer fails	4.10E-03
SUXFRELAYFAIL	Protection relay of startup transformer fails	1.40E-03
SUXFVOLTREGLOREC	Recovery of startup transformer regulators output voltage low fails	1.00E-01
SUXFVOLTREGLOWHE	Startup transformer regulators control output voltage low	3.00E-03
TRAINADCFAIL	DC power (battery) for transfer train A fails	9.50E-04
TRAINBDCFFAIL	DC power (battery) for transfer train B fails	9.50E-04
TRAINDCFAIL	Independent failure of DC transfer power battery	9.50E-04
TRANSFERRELAY	Independent failure of transfer relay	1.10E-02
TRANSFERRLYBUSA	Failure of transfer relay of train A	1.10E-02
TRANSFERRLYBUSB	Failure of transfer relay of train B	1.10E-02
TRANSFERSETHE	Operator sets transfer settings incorrectly	3.00E-03
TRANSFERSETREC	Recovery of incorrect transfer settings fails	1.00E-01
UV-RELAY-SET-HI	Operator sets setpoint of UV relays too high	3.00E-03
UV-RELAY-SET-REC	Recovery of incorrect calibration fails	1.00E-01
UVRELAYINDEPFAIL	Independent failure of undervoltage relay	1.40E-03
UVTIMERFAILS	Failure of timer associated with undervoltage relays	1.00E-04
VOLT-ANAL-HE	Human error in the system voltage analysis	3.00E-03

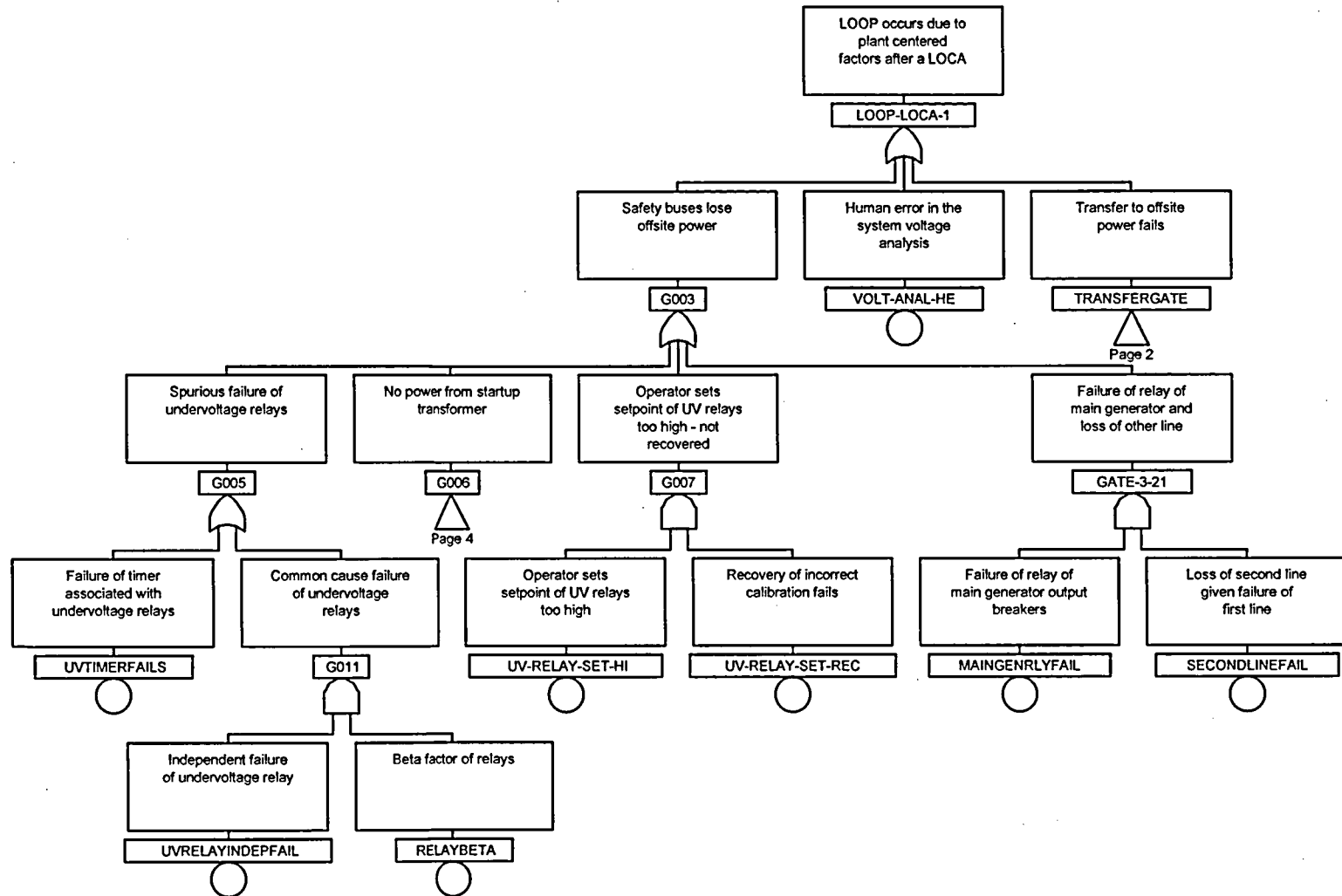


Figure E.2-1 LOOP Given LOCA Fault Tree for Plant Configuration #1

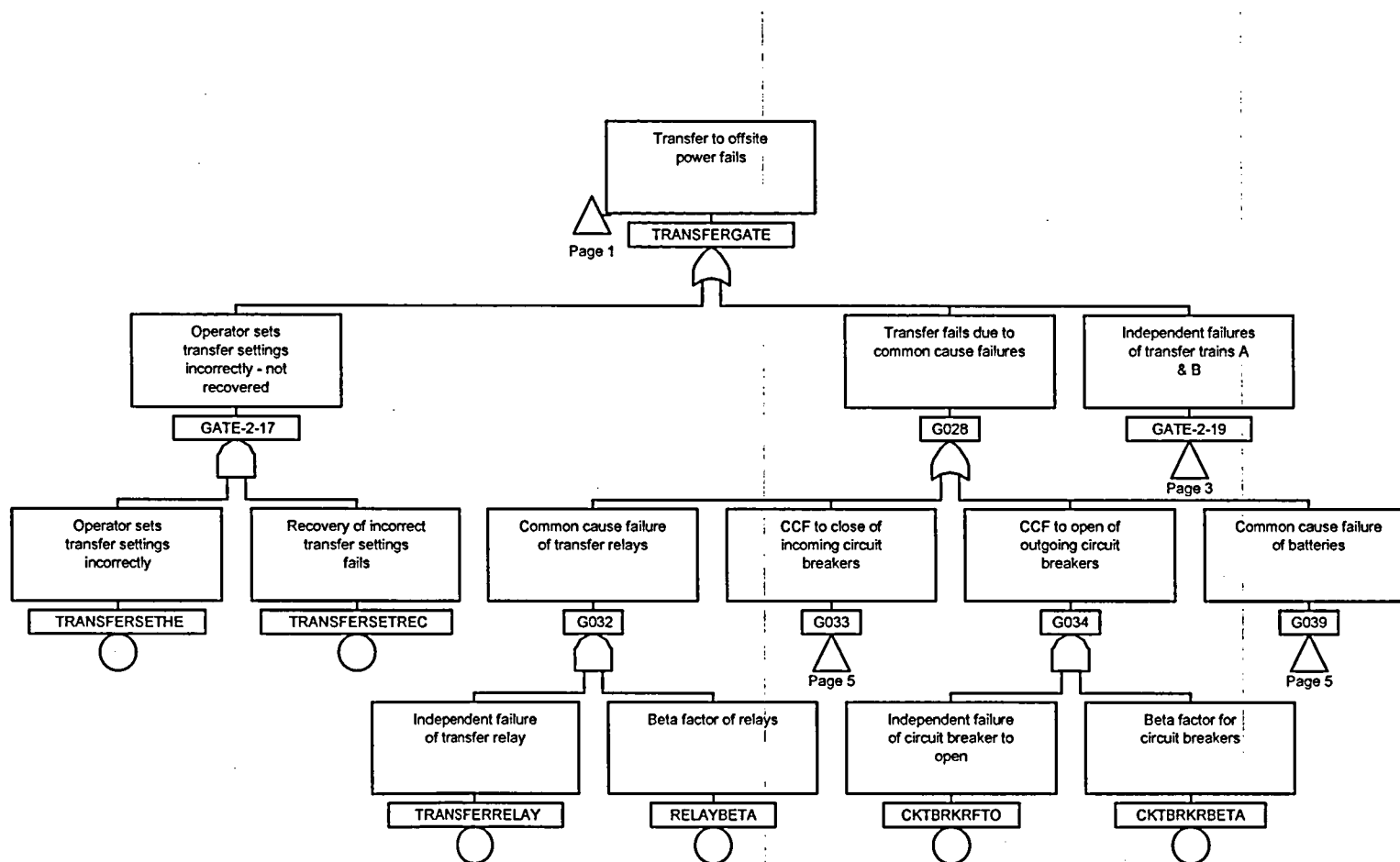


Figure E.2-1 LOOP Given LOCA Fault Tree for Plant Configuration #1 (Continued)

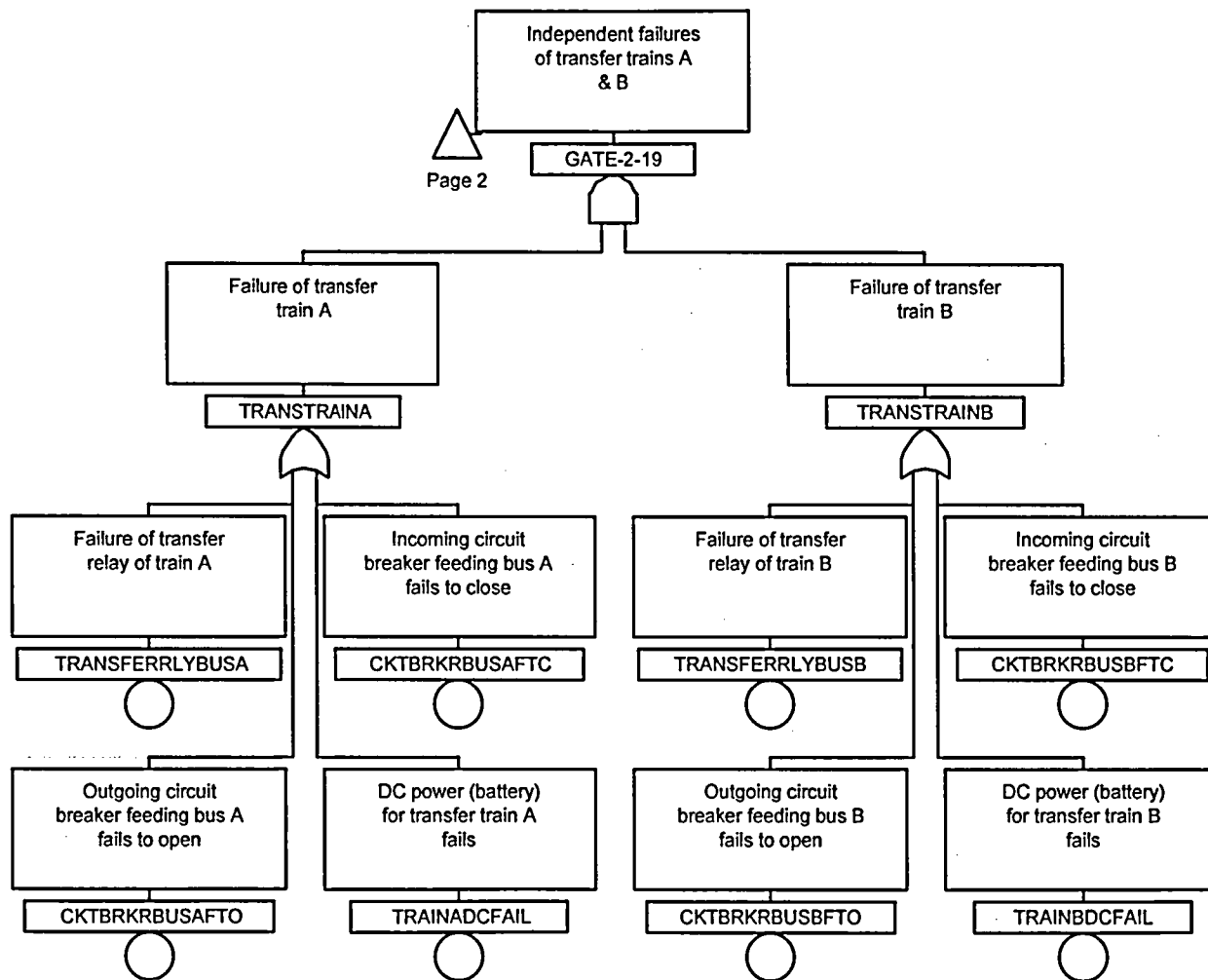


Figure E.2-1 LOOP Given LOCA Fault Tree for Plant Configuration #1 (Continued)

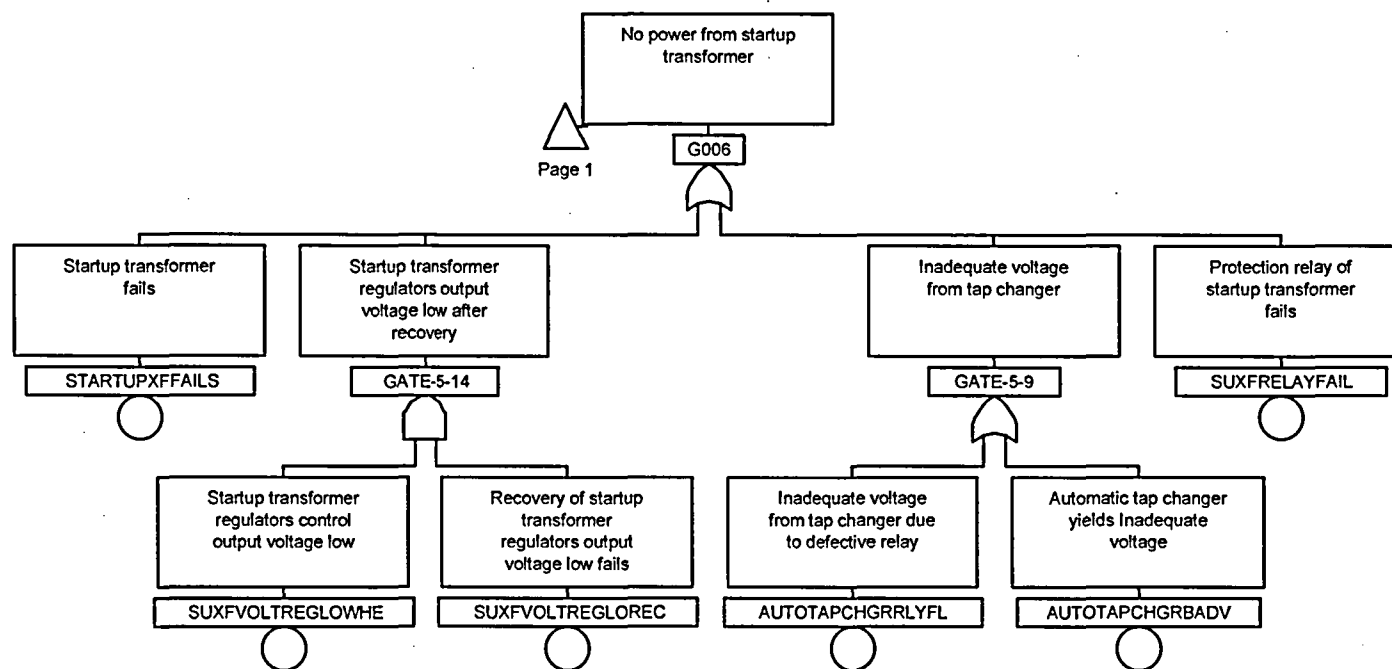


Figure E.2-1 LOOP Given LOCA Fault Tree for Plant Configuration #1 (Continued)

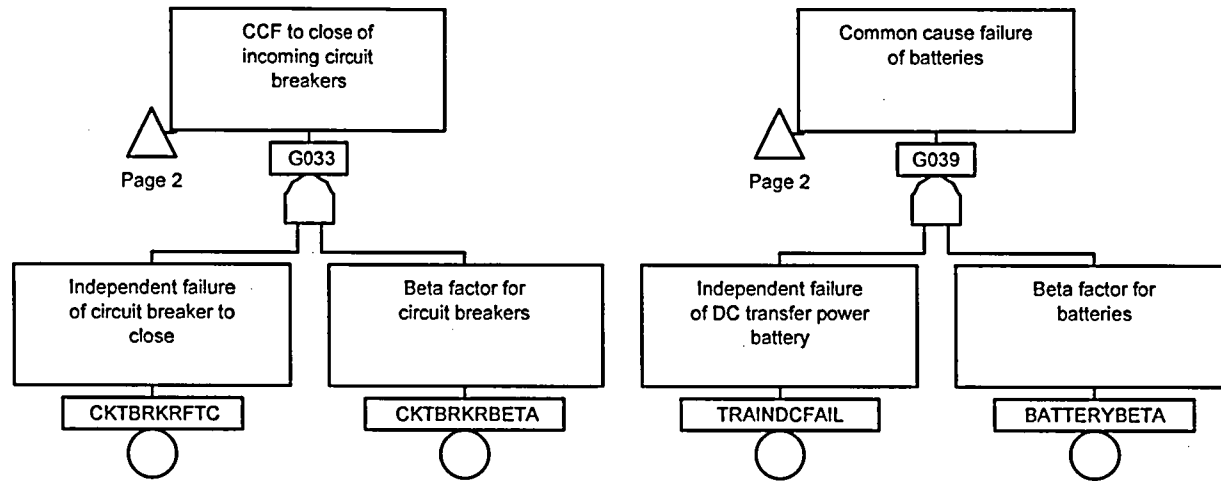


Figure E.2-1 LOOP Given LOCA Fault Tree for Plant Configuration #1 (Continued)

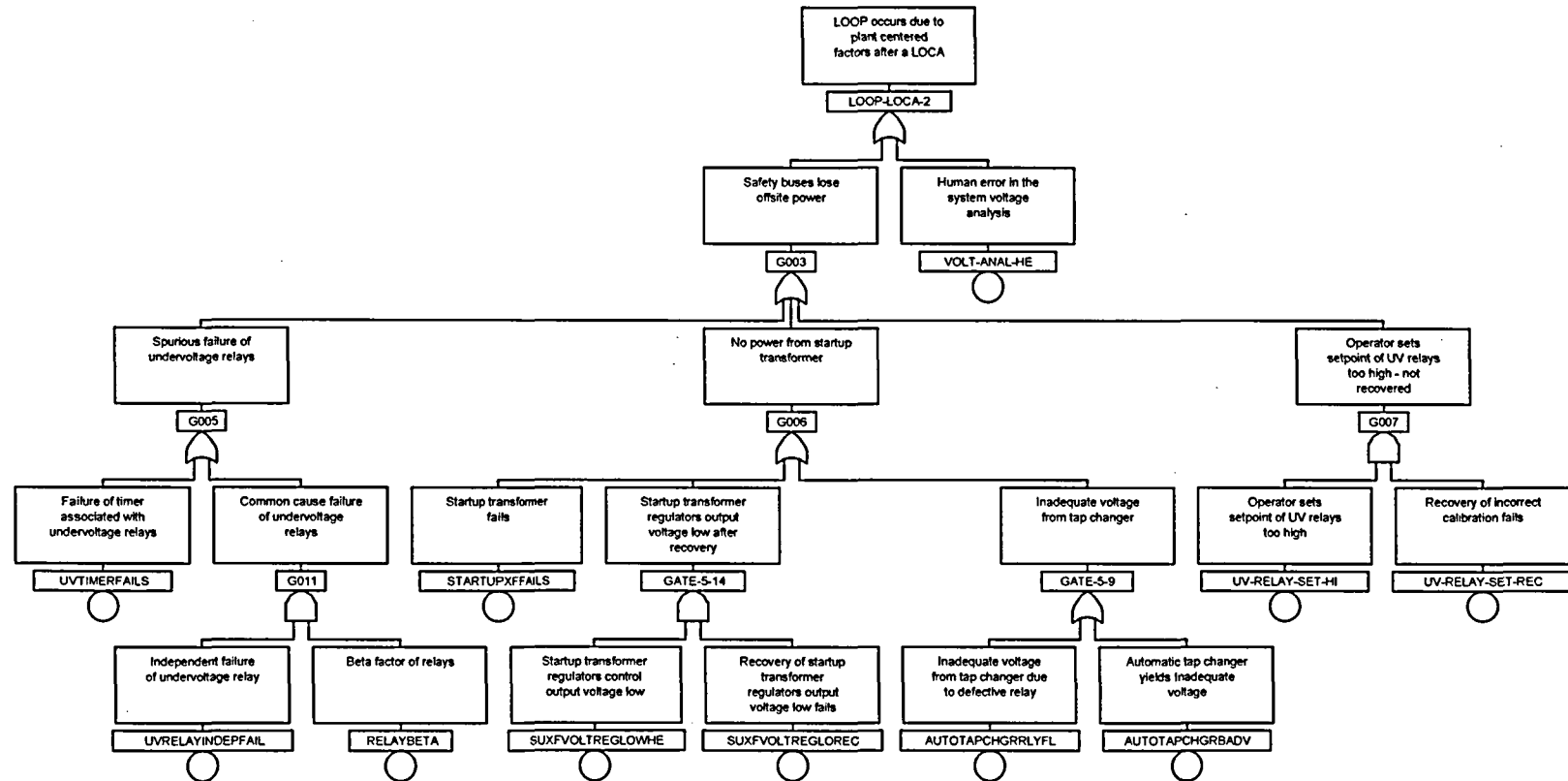


Figure E.2-2 LOOP Given LOCA Fault Tree for Plant Configuration #2